Sierra Club * National Wildlife Federation * Natural Resources Defense Council
Center for Biological Diversity * Friends of the Earth * Oil Change International
Labor Network for Sustainability * Western Organization of Resource Councils
350.org * League of Conservation Voters * Pembina Institute * Bold Nebraska
Nebraska Easement Action Team * Protect Our Winters
Center for International Environmental Law
Dakota Rural Action

Comments of the Sierra Club, *et. al.*, to the Department of State on the Draft Supplemental Environmental Impact Statement for the TransCanada Keystone XL Pipeline

Submitted April 22, 2013

Via electronic and U.S. mail to:
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INTRODUCTION

On behalf of the Sierra Club, National Wildlife Federation, Natural Resources Defense Council, the Center for Biological Diversity, 350.org, Friends of the Earth, Western Organization of Resource Councils, Oil Change International, the League of Conservation Voters, Labor Network for Sustainability, the Pembina Institute, Bold Nebraska, Nebraska Easement Action Team, the Center for International Environmental Law, Dakota Rural Action, and Protect Our Winters, we submit the following comments on the Draft Supplemental Environmental Impact Statement (DSEIS) for the proposed TransCanada Keystone XL Pipeline Project (hereinafter "Keystone XL" or "the project"). The Notice of Availability of the DSEIS for the project was published in the Federal Register on March 8, 2013, which indicated that the public comment period for this DSEIS closes on April 22, 2013.[1]

TransCanada re-applied for a Presidential Permit for Keystone XL on May 4, 2012 following the U.S. Department of State's ("State Department") denial of the previous Keystone XL application.[2] However, as explained below, the State Department initiated the new NEPA process with a "supplemental" EIS that reuses much of its environmental analysis prepared for the previous Keystone XL proposal. Therefore, our comment letters on the Draft, Supplemental, and Final EISs for the previous Keystone XL proposal are incorporated by reference and attached hereto.[3]

In the comments below, we express our concerns regarding the potential impacts of this project and the deficiencies in the State Department's latest analysis, and the need for further environmental review prior to any decision on TransCanada's application.

Perhaps the most glaring error in the DSEIS is the State Department's assertion that the tar sands will be developed at the same rate regardless of whether Keystone XL is built, which allows the DSEIS to avoid a full assessment of the project's direct, indirect, and cumulative impacts including its climate impacts. As explained below, this assumption is flawed and unsupported, is directly contradicted by nearly all sectors including the oil industry itself, and it violates the State Department's NEPA obligations.

The recent tar sands oil spill in Mayflower, Arkansas coupled with the fact that the July 2010 tar sands spill into the Kalamazoo River in Michigan is still not cleaned up almost three years later highlight the dangers of tar sands pipelines running through our communities and the

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[1] 78 Fed. Reg. 15012 (March 8, 2013).

[2] http://www.keystonepipeline-xl.state.gov/

[3] Exhibit 1 (Public Comments of the Sierra Club, *et al.*, on the TransCanada Keystone XL Pipeline Draft Environmental Impact Statement. July 2, 2010); Exhibit 2 (Public Comments of the Sierra Club, *et al.*, on the TransCanada Keystone XL Supplemental Environmental Impact Statement, July 6, 2011); Exhibit 2 (Public Comments of the Sierra Club, *et al.*, on the TransCanada Keystone XL Final Environmental Impact Statement and National Interest Determination, October 9, 2011).

lack of sufficient oversight and spill response capabilities. Yet the DSEIS fails to appropriately weigh the risks and likelihood of such spills and fails to consider whether TransCanada has a sufficient oil spill response plan in place. We must understand what went wrong in Arkansas before we can accurately assess the risks posed by Keystone XL, which would carry almost ten times as much oil as the failed Pegasus Pipeline.

Finally, the State Department has failed to provide sufficient opportunity for the public to meaningfully review the DSEIS. The 45-day comment period, which is the absolute minimum required under the law, is inappropriate for a project of this magnitude and level of public interest. Many of the key documents underlying the SEIS have not been made available to the public despite requests under the Freedom of Information Act ("FOIA"). Therefore, the State Department should address the issues raised below and re-issue a revised DSEIS with sufficient opportunity for public comment.

Despite these and other errors outlined in this comment letter, it is important to point out that the undersigned groups are in agreement with the State Department on some key issues. For example, the DSEIS that estimates that Keystone XL would create as few as 35 permanent jobs, some of which would be located in Canada, and that "employment and earnings impacts in the United States stemming from operations of the proposed Project would be negligible."[4] The DSEIS also acknowledges that with increasing levels of domestic oil production and decreasing domestic demand, the crude oil transported on Keystone XL would be refined into petroleum products that will be exported to overseas markets.[5] Finally, the stated "Purpose and Need" of the project claims that this is merely one of numerous other infrastructure options that could transport tar sands crude oil to market, which casts further doubt on the need for this project.

In short, the State Department's DSEIS demonstrates that Keystone XL would bring more costs than benefits to the American people, its economy and the environment, by acknowledging that that Keystone XL would create few permanent jobs, conceding that it would serve primarily as a means to export tar sands fuel to foreign countries, and failing to even set forth a compelling need for this project. For these reasons, combined with the long list of the project's environmental impacts and risks, we urge the State Department to recognize that Keystone XL would not serve the national interest.

I. PROCESS AND PUBLIC PARTICIPATION ISSUES

The National Environmental Policy Act ("NEPA") "is a procedural statute intended to ensure environmentally informed decision-making by federal agencies."[6] In taking a "hard look" at the consequences of major decisions, agencies are required to "involve the public in preparing

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[4] DSEIS, at 4.10-24.
[5] DSEIS, at 1.4-14,15.
[6] *Tillamook County v. U.S. Army Corps of Eng'rs*, 288 F.3d 1140, 1142 (9th Cir.2002).

and implementing their NEPA procedures."[7] Further, agencies have an obligation to afford "interested persons an opportunity to participate in the rule making."[8]

The very purpose of NEPA is to "ensure that federal agencies are informed of environmental consequences before making decisions and that the information is available to the public."[9] Indeed, meaningful and effective public participation is one of the cornerstones of NEPA. The regulations require that agencies shall "make diligent efforts to involve the public in preparing and implementing their NEPA procedures."[10] The agency must "hold or sponsor public hearings or public meetings whenever appropriate"[11] and "provide public notice of NEPA-related hearings, public meetings, and the availability of environmental documents" so that interested persons and agencies can be informed.[12] Also, federal agencies shall to the fullest extent possible "encourage and facilitate public involvement in decisions which affect the quality of the human environment."[13]

In this case, the public has not been afforded a meaningful opportunity to participate in the State Department's decision.

A. THE LATEST KEYSTONE XL PROPOSAL IS A NEW PROJECT THAT REQUIRES AN ENTIRELY NEW NEPA PROCESS

The State Department denied the previous Keystone XL application in January of 2012 and issued a Record of Decision pursuant to 40 C.F.R. § 1505.2 that formally ended the previous NEPA process. TransCanada subsequently reconfigured the project and submitted a second Presidential Permit application on May 4, 2012. The new Keystone XL proposal is different than its previous iteration, and includes a new and different purpose and need, a new route, and new and different environmental impacts. As such, the Department was required to start an entirely new NEPA process and follow all regulations as it would with any other new project.

NEPA regulations require agencies to prepare draft and final environmental impact statements, and allow and/or require agencies to "supplement" draft or final EIS's in certain circumstances.[14] Here, the State Department *began* with a "supplemental" EIS, recycling the vast majority of environmental analysis from the previous Keystone XL project. However, the State Department's previous NEPA process was tainted by potential conflicts of interest with Cardno Entrix, the company preparing the EIS, and TransCanada.

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[7] 40 C.F.R. § 1506.6(a) .
[8] 5 U.S.C. § 553(c).
[9] *Citizens to Preserve Better Forestry v. U.S.D.A.*, 341 F.3d 961, 970-71 (9th Cir. 2003).
[10] 40 C.F.R. § 1506.6(a).
[11] 40 C.F.R. § 1506.6(c).
[12] 40 C.F.R. § 1506.6(b).
[13] 40 C.F.R. § 1500.2(d).
[14] 40 C.F.R. § 1502.9.

According to NEPA regulations, "[a] final EIS shall be supplemented when a substantial change is made in the proposed action or when significant new information on the environmental impacts come to light.[15] In TransCanada's own 2012 Application for a Presidential Permit, the Keystone XL Project is referred to multiple times as a "new proposed action."[16] Thus, this is an entirely new proposed action rather than a substantial change in an existing proposed action.

As a fundamentally different proposed project, the latest Keystone XL Project should have initiated a new NEPA process undertaken by the State Department. Therefore, the State Department should reevaluate any and all areas of analysis that were taken from or that relied upon the 2011 FEIS.

B. THE PUBLIC DID NOT HAVE ACCESS TO DOCUMENTS ON WHICH THE EIS WAS BASED

The State Department failed to make available many of the key documents on which the DSEIS was based. For example, documents supporting the State Department's economic assumptions on rail capacity potential were not made available to the public. CEQ regulations require that documents underlying an EIS be made available to the public through FOIA:

> (f) Make environmental impact statements, the comments received, *and any underlying documents available to the public* pursuant to the provisions of the Freedom of Information Act (5 U.S.C. 552), without regard to the exclusion for interagency memoranda where such memoranda transmit comments of Federal agencies on the environmental impact of the proposed action. Materials to be made available to the public shall be provided to the public without charge to the extent practicable, or at a fee which is not more than the actual costs of reproducing copies required to be sent to other Federal agencies, including the Council.[17]

Courts have found NEPA violations where an agency does not make documents available to the public during the comment period.[18]

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[15] 22 C.F.R. § 161.9(k).
[16] TransCanada, "Application of TransCanada Keystone Pipeline, L.P. for a Presidential Permit Authorizing the Construction, Connection, Operation, and Maintenance of Pipeline Facilities for the Importation of Crude Oil to be Located at the United States-Canada Border," (May 4, 2012) at 46.
[17] 40 C.F.R. § 1506.6 (emphasis added).
[18] *Idaho ex rel. Kempthorne v. U.S. Forest Serv.*, 142 F. Supp. 2d 1248, 1260-62, 63 (D. Idaho 2001); *See also Envtl. Prot. Info. Ctr. v. Blackwell*, 389 F. Supp. 2d 1174, 1204-05 (N.D. Cal. 2004) (depriving the public of biological opinion upon which agency relied in NEPA process rendered EA deficient); *Idaho Sporting Cong. v. Thomas*, 137 F.3d 1146, 1150 (9th Cir. 1998) (*overruled by The Lands Council v. McNair*, 537 F.3d 981 (9th Cir. 2008) on other grounds)("we conclude that NEPA requires that the public receive the underlying environmental data from which a Forest Service expert derived her opinion.");

The State Department published the Keystone XL DSEIS on its website on March 1, 2013, with the DSEIS officially published in the Federal Register on March 8, 2013, and announced a 45-day comment period ending on April 22, 2013, which is the shortest possible comment period required by NEPA regulations.[19] However, the State Department did not provide access to many of the documents on which the EIS was based.

The Sierra Club submitted a FOIA request for these underlying documents on March 20, 2013, and requested expedited processing pursuant to 22 C.F.R. § 171.12(b).[20] Sierra Club pointed out that there is a compelling need for the information because it is urgently needed in order to inform the public concerning actual government activity and has a particular value that will be lost if not distributed quickly. The National Wildlife Federation also informally requested these documents on March 28, 2013.

On April 5, 2013, the State Department notified Sierra Club that its request for expedited processing was denied.[21] Additional documents were requested via email by Natural Resources Defense Council (NRDC) on April 10, 2013. That same day, State Department released some of the documents to NRDC, leaving fewer than 12 days for public review of these critical, technical documents. Furthermore, there are still underlying documents that have yet to be made available to the public.

The State Department did not provide sufficient time to review the released material and continues to withhold underlying documents that are necessary for meaningful participation and comment on the DSEIS.

C. THE STATE DEPARTMENT'S PUBLIC NOTICE AND COMMENT PERIOD WAS INSUFFICIENT

The State Department did not allow sufficient time for public notice and comment. NEPA regulations require that an agency "make diligent efforts to involve the public" in the EIS process, and to that end must provide an opportunity for public comment.[22] However, agencies "shall allow not less than 45 days for comments on draft statements."[23] With significant, controversial decisions such as this one, it is not uncommon for agencies to provide the public

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Gerber v. Norton, 294 F.3d 173 (D.C. Cir. 2002)(public not able to meaningfully comment because agency failed to provide underlying maps agency used to reach a decision to issue an ESA Section 10 permit); *Grazing Fields Farm v. Goldschmidt*, 626 F.2d 1068, 1073 (1st Cir. 1980)(rendering NEPA analysis deficient because agency failed to circulate data supporting agency decision, thus hindering public scrutiny of agency decision-making).

[19] 40 C.F.R. § 1506.10(c).

[20] Attached as Exhibit 4.

[21] Attached as Exhibit 5.

[22] 40 C.F.R. § 1506.6(a).

[23] 40 C.F.R. § 1506.10(c).

with far more than 45 days. For example, the Department of the Interior provided a 180-day extension of the public comment period for an offshore oil and gas leasing program to "give states, stakeholders, and affected communities the opportunity to provide input on how, whether, and where the Nation's offshore areas should be considered as part of the Nation's energy strategy."[24] Public comment periods have also been extended when documents are omitted from the package for public review.[25] In this case, the State Department has provided only the minimum 45-day comment period required under the law.

Forty-five days is entirely insufficient for the public to meaningfully comment on a project of this magnitude and importance. Environmental groups formally requested that the comment period be extended on March 27, 2013, pointing out that many of the studies on which the DSEIS were based had not been made available to the public as required by 40 C.F.R. § 1506.6(f).[26] Several groups sent a second request for an extension on April 8, 2013, after a major tar sands oil spill in Mayflower, Arkansas, explaining that the public and the agencies need to know what went wrong there before it can be assured of the safety of Keystone XL.[27] Finally, groups sent a third request for an extension on April 12, 2013, arguing that the State Department's subsequent release of some, but not all, underlying documents left insufficient time for the public to conduct a meaningful review of the proposed project.[28] The State Department sent a letter dated April 19, 2013 denying these requests but without providing a reason for the denial of the request.

In addition, the State Department failed to hold adequate public hearings. NEPA regulations require agencies to "hold or sponsor public hearings or public meetings whenever appropriate," especially where there is "[s]ubstantial environmental controversy concerning the proposed action or substantial interest in holding the hearing."[29] In compliance with this regulation, the responsible action officer at the State Department must submit a recommendation regarding the need for public hearings.[30] Here, the State Department scheduled only one hearing in Nebraska, which is entirely insufficient for Keystone XL. Given that the proposed project would also run through Montana and South Dakota, there should have been at least two additional hearings held in those states. Keystone XL is a proposed action with effects of both national and local concern and as such, public input should be solicited at both the national and local levels.

Finally, the State Department did not notify by mail any of the national environmental groups that have been heavily involved in this project. NEPA regulations require that the State Department "[i]n the case of an action with effects of national concern notice shall include

[24] 74 Fed. Reg. 41.
[25] 65 Fed. Reg. 80451.
[26] Attached as Exhibit 6. *See also supra* Section I.B.
[27] Attached as Exhibit 7.
[28] Attached as Exhibit 8.
[29] 40 C.F.R. § 1506.6(c).
[30] 22 C.F.R. § 161.9(f)(4).

publication in the Federal Register and notice by mail to national organizations reasonably expected to be interested in the matter."[31] The Keystone XL pipeline is unquestionably a project that would have effects of national concern. Most, if not all of the undersigned organizations have commented extensively on the current Keystone XL proposal as well as the previous proposal, and have otherwise demonstrated to the State Department that they are interested in this matter. Nonetheless, the State Department failed to notify any groups by mail as 40 C.F.R. § 1506.6 requires, which renders the State Department's 45-day comment period even more inadequate.

D. THE STATE DEPARTMENT MUST PREPARE A SUPPLEMENTAL EIS

The recent tar sands pipeline spill in Arkansas constitutes significant new circumstances and information that is relevant to environmental concerns and the potential impacts of Keystone XL. The State Department must prepare a Supplemental EIS that considers the information surrounding the incident.

Agencies are required to prepare supplemental EIS's if: "(i) The agency makes substantial changes in the proposed action that are relevant to environmental concerns; or (ii) There are significant new circumstances or information relevant to environmental concerns and bearing on the proposed action or its impacts."[32]

On March 29, ExxonMobil's Pegasus Pipeline ruptured in Mayflower, Arkansas, sending thousands of barrels of tar sands-derived crude oil flowing through the yards, driveways, and streets of a residential neighborhood. The Pipeline and Hazardous Materials Safety Administration (PHMSA) has issued a Corrective Action Order (CPF No. 4-2013-5006H) and has initiated an investigation into the incident.[33] However, PHMSA acknowledges that important questions remain unknown at this time, including but not limited to:

- What caused the pipeline to rupture?
- How much crude oil was actually released?
- Why did it take nearly twenty minutes for the pipeline to be shut down, forty five minutes for the incident to be reported, and ninety minutes for responders to arrive?
- How was the released oil able to reach homes and waterways so quickly, particularly when the spill occurred in a "high consequence area" under pipeline safety regulations?
- What is the full extent of the environmental and health impacts from this spill?

[31] 40 C.F.R. § 1506.6(b)(2).
[32] 40 C.F.R. § 1502.9(c)(1).
[33] Attached as Exhibit 9.

The public must have answers to these questions before it can assess the true risks of Keystone XL, which would carry nearly ten times as much oil as the Pegasus Pipeline. The DSEIS acknowledges that tar sands diluted bitumen poses new and serious risks to waters, human health, communities and natural resources, and that those risks are not properly understood. The disaster in Mayflower demonstrates, once again, the severity of these risks and the need to evaluate them. The public, the State Department, and other federal agencies involved in the Keystone XL decision must know what went wrong with the Pegasus pipeline before they can evaluate whether similar accidents are likely to occur on the much larger Keystone XL.

The Sierra Club has sought information about this incident from PHMSA through FOIA, but has not yet received any responsive documents.[34] Undersigned groups have also requested an extension of the public comment period until we learn what went wrong in Mayflower.[35]

The Keystone XL DSEIS does not include a project-specific Emergency Response Plan, so critical information such as worst-case discharge estimates and lists of response capabilities (*e.g.,* equipment and personnel) remain unavailable to the public. *See* Section II.D.4. The public cannot assess the safety of Keystone XL until these documents are disclosed.

E. THE STATE DEPARTMENT FAILED TO SCREEN FOR ORGANIZATIONAL CONFLICTS OF INTEREST

In 2011, the Office of Inspector General ("OIG") conducted a special review of the State Department's evaluation of the previously proposed Keystone XL project and released a February 2012 report of its findings and recommendations ("OIG Report").[36] The investigation was launched in response to concerns voiced by members of Congress that the State Department may have mishandled the Environmental Impact Statement and National Interest Determination processes. One of the primary issues of concern was the State Department's selection of Cardno Entrix as a third-party contractor to prepare the EIS for Keystone XL and specifically, whether there were organizational conflicts of interest between TransCanada and Cardno Entrix.

The OIG Report identified several serious flaws in the State Department's selection process, including the failure to verify and conduct an independent inquiry into the organizational conflict of interest statements submitted by Cardno Entrix. The report goes on to recommend that the State Department redesign its process for selecting and using third-party contractors in order to improve its organizational conflict of interest screening process.

In view of OIG's findings, the State Department should have demonstrated transparency in its selection of Environmental Resources Management, Inc. ("ERM") to prepare the latest DSEIS for the Keystone XL project. The State Department should have disclosed and addressed potential conflicts of interest between TransCanada and ERM within the DSEIS. Instead, it

[34] Attached as Exhibit 10.
[35] See Ex. 7.
[36] Attached as Exhibit 11.

appears that the State Department failed to comply with the OIG recommendations as well as its own Interim Guidance, thereby violating its agency responsibilities under NEPA:

> Contractors shall execute a disclosure statement prepared by the lead agency, or where appropriate the cooperating agency, specifying that they have no financial or other interest in the outcome of the project.[37]

The State Department failed to independently verify that ERM has "no financial or other interest in the outcome of the project." In fact, a proper screening of ERM's conflict of interest statements would have revealed numerous organizational conflicts of interest between TransCanada and ERM. See Sierra Club's letter to the Office of Inspector General.[38] The DSEIS is therefore inherently flawed as "an undetected organizational conflict of interest could affect the objectivity of a contractor's work or at least call its objectivity into question." The State Department must fulfill its agency responsibilities in accordance with NEPA by undertaking an independent inquiry into ERM's conflicts of interest materials or by selecting a different third-party contractor to prepare the EIS for Keystone XL. Either way, the State Department has an obligation to prove the credibility of environmental analyses to the public by providing access to its review and selection process.

II. THE DSEIS FAILS TO SATISFY THE NATIONAL ENVIRONMENTAL POLICY ACT

A. RELEVANT NEPA LEGAL REQUIREMENTS

These comments are submitted to address the DSEIS' compliance with National Environmental Policy Act (NEPA). NEPA is our "basic national charter for the protection of the environment."[39] Congress enacted NEPA "[t]o declare a national policy which will encourage productive and enjoyable harmony between man and his environment; to promote efforts which will prevent or eliminate damage to the environment and biosphere and stimulate the health and welfare of man; [and] to enrich the understanding of the ecological systems and natural resources important to the Nation."[40] To accomplish these purposes, NEPA requires all agencies of the federal government to prepare a "detailed statement" that discusses the environmental impacts of, and reasonable alternatives to, all "major Federal actions significantly affecting the quality of the human environment."[41] This statement is commonly known as an environmental impact statement (EIS).[42]

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[37] 40 C.F.R. § 1506.5(c).
[38] Attached as Exhibit 12.
[39] 40 C.F.R. § 1500.1.
[40] 42 U.S.C. § 4321.
[41] 42 U.S.C. § 4332(2)(C).
[42] 40 C.F.R. § 1502.

The EIS must "provide full and fair discussion of significant environmental impacts and shall inform decision-makers and the public of the reasonable alternatives which would avoid or minimize adverse impacts or enhance the quality of the human environment."[43] This discussion must include an analysis of "direct effects," which are "caused by the action and occur at the same time and place," as well as "indirect effects which . . . are later in time or farther removed in distance, but are still reasonably foreseeable."[44] An EIS must also consider the cumulative impacts of the proposed federal agency action together with past, present and reasonably foreseeable future actions, including all federal and non-federal activities.[45] Furthermore, an EIS must "rigorously explore and objectively evaluate all reasonable alternatives" to the proposed project.[46]

In this case, NEPA requires that the State Department's DSEIS must assess all impacts of the Keystone XL project, including any associated refining facilities, and the indirect impacts of extraction and end use combustion.[47] Specifically, the EIS must "present the environmental impacts of the proposal and the alternatives in a comparative form, thus sharply defining the issues and providing a clear basis for choice among options by the decision maker and the public."[48] In order to adequately assess the environmental impacts of the project and of reasonable alternatives to the proposed project, the DSEIS must assess the direct, indirect, and cumulative impacts that the proposed project and each alternative would have.

For the reasons stated below, the DSEIS for the Keystone XL project is legally and technically flawed because the State Department failed to adequately assess all of the direct, indirect and cumulative impacts of the project. We request that the State Department fully and completely address the following concerns and re-issue the DSEIS for further public comment. An EIS that fairly and accurately addresses all the impacts of Keystone XL will make it evident that Keystone XL is not in the national interest and should be denied.

B. THE DSEIS' PURPOSE AND NEED IS FLAWED

1. The Purpose and Need is Based on Inaccurate Data and Assumptions and Forecloses Consideration of Reasonable System Alternatives

The State Department must evaluate the purpose and need for the project using unbiased and accurate information to assess the likely future demand for heavy tar sands crude from Canada. No accurate and reliable information on likely future demand has been developed for the DSEIS. Without an adequate assessment of the purpose and need for the project, the entire DSEIS is deficient – the State Department cannot possibly take a "hard look" at alternatives and

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[43] 40 C.F.R. § 1502.1.
[44] 40 C.F.R. § 1508.8.
[45] 40 C.F.R. § 1508.7.
[46] 40 C.F.R. § 1502.14(a).
[47] 40 C.F.R. §§ 1502.14 and 1502.16.
[48] 40 C.F.R. § 1502.14.

balance the true costs and benefits of the project as it considers the national interest unless it has first established that the need for the project as proposed is legitimate. The State Department's failure to accurately define the scope of the project's purpose and need, has led to the State Department's erroneous selection of alternatives.

> When a federal agency prepares an Environmental Impact Statement (EIS), it must consider "all reasonable alternatives" in depth. 40 C.F.R. § 1502.14. No decision is more important than delimiting what these "reasonable alternatives" are. That choice, and the ensuing analysis, forms "the heart of the environmental impact statement." 40 C.F.R. § 1502.14. To make that decision, the first thing an agency must define is the project's purpose. *See Citizens Against Burlington, Inc. v. Busey*, 938 F.2d 190, 195-96 (D.C.Cir.1991). The broader the purpose, the wider the range of alternatives; and vice versa … One obvious way for an agency to slip past the strictures of NEPA is to contrive a purpose so slender as to define competing "reasonable alternatives" out of consideration (and even out of existence). … If the agency constricts the definition of the project's purpose and thereby excludes what truly are reasonable alternatives, the EIS cannot fulfill its role. Nor can the agency satisfy the Act. 42 U.S.C. § 4332(2)(E).[49]

The DSEIS here is similarly flawed because the State Department has limited the context of the project's purpose and need thereby foreclosing consideration of reasonable alternatives that are necessary for a robust National Interest Determination. The DSEIS states the purpose and need for the proposed pipeline project is to "provide the infrastructure to transport WCSB crude oil from the border with Canada to existing pipeline facilities" for subsequent delivery to Gulf Coast area refineries" The DSEIS further defines the purpose and need as "one potential transportation option for crude oils" from WCSB and Bakken "that would compete with other transportation options." "Those WCSB and Bakken crude oils would also compete in the market with other domestic and foreign sources of crude oil available to the Gulf Coast area refiners."[50] The purpose and need is inappropriately constrained to consider only modes of oil transport from point A to point B to meet specific refinery demand.

This limited context is flawed in multiple ways. First, it bases project need on an alleged refinery demand. In other words, Gulf area refineries can only take in tar sands and other heavy sour crudes because of recent upgrades to facilities to exclusively process those types of unconventional crudes. These upgrades were the result of refinery operator business decision making. Instead, NEPA and any National Interest Determination justification necessarily mandates a wider lens through which to analyze a proposed project of this kind. As such, the State Department must define the project's purpose and need based on nationwide oil and energy

[49] *Simmons v. U.S. Army Corps of Engineers*, 120 F.3d 664, 666-67 (7th Cir. 1997).
[50] DSEIS, at 1.3-1 to 2.

consumption demands in light of threats of catastrophic climate disruption and ambitious federal policy efforts already underway to cut greenhouse gas emissions and reduce our nation's dependence on oil and other high carbon fuels. By defining the project more broadly, as required by NEPA, the analysis would include a wider range of reasonable alternatives, including cleaner, lower carbon pathways to meet demand, which would provide a more accurate and unbiased assessment of the true costs and benefits of increasing transport of carbon intensive tar sands oil through America as one possible way of fulfilling national oil and fuel demands.

Even the State Department itself states that one of the factors it considers in making the national interest determination is the "relationship between the proposed Project and goals to reduce reliance on fossil fuels and to increase use of alternative and renewable energy sources."[51] Because the NEPA review serves as the basis for the State Department's national interest determination, the State Department is obligated to conduct a more broadly defined analysis. Indeed, the analysis that refiners made to reach the conclusion that exclusively refining heavy sour crudes is in their best interest would seem to contradict national interest priorities. It is not the role of the federal government to mitigate the consequences of shortsighted corporate decision making that led Gulf Coast refiners to retool their facilities in this way. Indeed, there is no substantial evidence demonstrating that large-scale increases in WCSB oil demand exists to meet America's fuel demands or that demand for WCSB oil is likely to develop. In fact, WCSB oil becomes less desirable in light of federal policy boosting fuel economy standards and the devastating tar sands oil spills occurring in communities across America. As the DSEIS states, the EIA projects that US demand will decrease going forward. The purpose and need makes the flawed assumption that WCSB tar sands crude would be competing only with other high carbon and conventional crude oils, and fails to consider cleaner, renewable and low carbon fuels as competitors in meeting energy demands. By limiting the purpose and need of the project to a mere oil transport option to serve refiner demand for tar sands crude, the State Department forecloses an appropriate range of reasonable alternatives and consideration of a critical national interest determination factor.

By defining the purpose and need as a mere transport option to meet Gulf coast refinery capacities, the State Department has limited the range of alternatives to a host of prospective route and rail transport alternatives. The DSEIS rejects consideration of alternative fuels and conservation based on flawed market assumptions. Further, by limiting the range of alternatives to a set of oil transport options, the State Department has positioned itself to conclude that the impacts of the proposed project are a foregone conclusion; i.e., they would happen anyway since one of the other possible alternative modes of transport is sure to come online whether or not the proposed project is approved. Indeed, the State Department has done here what the courts have rejected – it has "contrive[d] a purpose so slender as to define competing 'reasonable alternatives' out of consideration."[52]

[51] DSEIS, at 1.3-3.
[52] *See*, fn. 49.

In addition, the purpose and need also makes the flawed assumption that WCSB oil will get to the Gulf Coast or to other Canadian refiners or export facilities regardless of whether the proposed project is built. To date, however, Canadian citizens have successfully halted proposals to increase Canadian pipeline capacity and other modes of transport to get tar sands from Alberta to export markets. And, as described in Section II.D.1, plans for alternative U.S. based transport methods, including other pipelines and rail, that the State Department purports would come online whether or not the proposed project is built, have not yet been fully developed or proven to have the capacity to safely transport an additional 830,000 barrels of tar sands oil per day to the Gulf Coast.

2. <u>The DSEIS Fails to Demonstrate a Need for the Project, or Demonstrate that Approval is in the National Interest</u>

Even if the stated Purpose and Need were adequate, the State Department has utterly failed to set forth any real need for Keystone XL. The previous Draft Environmental Impact Statement for Keystone XL, published on April 20, 2010, included a lengthy discussion of the project's need, including a discussion of the supply of heavy crude oil from the WCSB, the demand for heavy crude oil in PADD III, the transport of crude oil from the WCSB to PADD III, and future infrastructure scenarios.[53] That discussion is entirely absent from the DSEIS.

The DSEIS goes to great lengths to describe all of the infrastructure projects that are likely to materialize if Keystone XL is denied, but does not even endorse Keystone XL as necessary:

> The proposed Project would provide one potential transportation option for crude oils sourced from the WCSB and Bakken that would compete with other transportation options, both pipeline and rail, for those sources of crude oil.[54]

This watered-down approach to the Purpose and Need serves only to avoid an analysis of the project's direct and indirect impacts. By insisting that other infrastructure projects would be built if not for Keystone XL, the DSEIS attempts to avoid a causal connection between Keystone XL and increased tar sands development. As set forth below, that assertion is arbitrary and capricious for a number of reasons, and contradicts numerous statements by oil industry executives and analysts explaining that Keystone XL is crucial to the growth of the tar sands industry.

Thus, the DSEIS fails to demonstrate a true need for the project or that the proposed project is in the national interest.

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[53] DEIS, at 1.4 to 1.8, <u>http://keystonepipeline-xl.state.gov/documents/organization/182325.pdf.</u>
[54] DSEIS, at 1.3-2. *See* section II.D.1, commenters do not agree that these other transport alternatives are likely to come online if the proposed project is denied.

3. <u>Because the Purpose and Need Includes National Interest Factors, Those Must Be Analyzed Throughout the EIS.</u>

The DSEIS states the State Department's Purpose and Need as follows:

> The Department's purpose, therefore, is to consider Keystone's application in terms of how the proposed Project would serve the national interest taking into account the proposed Project's potential environmental, cultural, economic, and other impacts.[55]

Some of the key factors that the DSEIS says it will take into account in considering whether the pipeline would serve the national interest are:

- Environmental impacts of the proposed Project;
- Impacts of the proposed Project on the diversity of supply and security of transport pathways for crude oil imported to the United States;
- Impact of a cross-border facility on the relations with the country to which it connects;
- Stability of various foreign suppliers of crude oil and the ability of the United States to work with those countries to meet overall environmental and energy security goals;
- Impact of proposed projects on broader foreign policy objectives, including a comprehensive strategy to address climate change, bilateral relations with neighboring countries; and energy security;
- Economic benefits to the United States of constructing and operating the proposed Project; and
- Relationships between the proposed Project and goals to reduce reliance on fossil fuels and to increase use of alternative and renewable energy sources."[56]

Therefore, the question of whether the project is in the national interest, based on those and other factors, must be analyzed throughout the DSEIS. In the absence of these factors, the DSEIS cannot serve as sufficient basis for State's national interest determination.

C. INADEQUATE ANALYSIS OF ALTERNATIVES

NEPA requires an analysis of alternatives, which is "the heart of the environmental impact statement."[57] "It should present the environmental impacts of the proposal and the alternatives in comparative form, thus sharply defining the issues and providing a clear basis for choice among options by the decisionmaker and the public."[58]

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[55] DSEIS, at 1.3-2.
[56] DSEIS, at 1.3-2 to 3.
[57] 40 C.F.R. § 1502.14.
[58] *Id.*

1. <u>The DSEIS Fails to Adequately Consider the "No Action" Alternative</u>

a. Legal Background

The CEQ NEPA regulations require agencies to include the no action alternative in an EIS.[59] The "'no action' status quo alternative...is the standard by which the reader may compare the other alternatives' beneficial and adverse impacts related to the applicant doing nothing."[60]

b. The No Action Alternatives in the Keystone XL DSEIS

The DSEIS includes a discussion of three "no action" alternatives in Section 5.1: the "status quo scenario," the "rail/pipeline scenario," and the "rail/tanker scenario."[61] Under the Status Quo Scenario, Keystone XL would not be built and the proposed Project would not be approved and/or built.

The Rail/Pipeline Scenario assumes that "a similar volume of crude oil (e.g., up to 730,000 bpd of WCSB crude oil and up to 100,000 bpd of Bakken crude oil) would be transported by rail to Stroud, Oklahoma, and the majority of that crude oil would then be delivered by existing pipeline to the Gulf Coast area."[62]

The Rail/Tanker Scenario, is similar to the Rail/Pipeline scenario, except it also assumes the "transport of WCSB crude oil via existing rail lines to Port Rupert, British Columbia; transfer of crude oil to tankers; and tanker transport of the crude oil down the Pacific Coast, through the Panama Canal, and up through the Gulf of Mexico for delivery to the TCG refineries."[63]

The State Department's analysis of "no action" alternatives serves to avoid a comparison of the proposal's impacts (namely, impacts on climate change, impacts on tar sands development, and impacts of refineries) by assuming that the impacts of the project would be the same under the "no action" alternative. The State Department reasoned that if not for this project, some other project would be built that would have similar impacts. *See* Section II.D.1.

c. State Department Did Not Adequately Consider the "Status Quo" Alternative

The State Department failed to adequately analyze the true "no action" alternative- the status quo scenario- as required by NEPA. Courts have repeatedly held that the no action

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[59] 40 C.F.R. 1502.14(d). Also, *Ctr. for Biological Diversity v. U.S. Bureau of Land Mgmt.*, 746 F. Supp. 2d 1055, 1090 (N.D. Cal. 2009).
[60] *Kilroy v. Ruckelshaus*, 738 F.2d 1448, 1453 (9th Cir.1984) (internal citation and quotation omitted).
[61] DSEIS, at 5.1-2 to 3.
[62] DSEIS, at 5.1-3.
[63] DSEIS, at 5.1-2.

alternative, against which the impacts of the proposed project and any alternatives, should be the current level of activity, or the status quo. *Custer County Action Assoc. v. Garvey,* 256 F.3d 1024, 1040 (10th Cir.2001) (the "no-action" alternative serves to ensure that "agencies compare the potential impacts of the proposed major federal action to the known impacts of maintaining the status quo."); *Colorado Off-Highway Vehicle Coal. v. United States*, 505 F. Supp. 2d 808, 817 (D. Colo. 2007)("the current level of activity is used as a benchmark" for the no action alternative); *Association of Pub. Agency Customers, Inc. v. Bonneville Power Admin.,* 126 F.3d 1158, 1188 (9th Cir.1997); *League to Save Lake Tahoe v. Tahoe Reg'l Planning Agency*, 739 F. Supp. 2d 1260, 1274 (E.D. Cal. 2010) (the no action alternative should describe the "baseline conditions ... against which to compare predictions of the effects of the proposed action.") (quoting *Am. Rivers v. Fed. Energy Reg. Comm'n*, 201 F.3d 1186, 1195 n. 15 (9th Cir.1999) (quotation omitted).

Out of its 62-page analysis of "no action" alternatives, the State Department's consideration of the "status quo" scenario consists entirely of the following paragraph:

> Under the Status Quo Scenario, the proposed Project would not be approved and/or built. Under this scenario, there would be no new impacts to any resources from the proposed Project route. To the extent some impacts are occurring, or could occur, as a result of transporting WCSB and Bakken crude oil by existing pipelines and rail (i.e., air emissions, noise, and potential release risk), these impacts are assumed to continue.[64]

Rather than adequately discuss the "baseline conditions" that would occur under the status quo, the DSEIS violates 40 C.F.R. 1502.14(d). The DSEIS does not fully develop this scenario, and thus it is impossible to measure the impacts of Keystone XL against it.

For example, there is no discussion of what the status quo scenario would mean in terms of tar sands development and corresponding GHG emissions. The State Department relies on several studies conducted by EnSys Energy & Systems, Inc., including the 2010 "Keystone XL Assessment" (EnSys Report) for the U.S. Department of Energy (DOE) Office of Policy and International Affairs.[65] The EnSys Report was intended to be "an evaluation of the impacts on U.S. and global refining, trade and oil markets of the Keystone XL project to bring additional Canadian crudes, including tar sands, into the U.S."[66]

The EnSys Report unequivocally shows that Keystone XL would increase tar sands production as compared to the status quo. The Report compares various pipeline scenarios and the resulting impacts on tar sands production. The relevant comparison should be between the scenario where Keystone XL is built, and the status quo, which is represented by the "No

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[64] DSEIS, at 5.1-3.
[65] EnSys Keystone XL Assessment, Final Report (Dec. 23, 2010).
[66] EnSys Report, at 1.

Expansion" scenario. The No Expansion scenario assumes that no additional pipelines are built beyond what is currently built or under construction. The EnSys report concludes that under the No Expansion scenario, there would be "significant impacts on the disposition of WCSB crudes" because production would be curtailed by 2024 because of limited export pipeline capacity.[67] By contrast, building Keystone XL would allow tar sands production to increase through 2030: "[W]hile Keystone XL, coming on line in 2013, would add to the excess in export capacity through 2020, its capacity- or an alternative (i.e. other projects in Section 3.2)- would be needed soon after 2020 to sustain WCSB production at the levels predicted by CAPP."[68]

Most importantly, the EnSys Report found that Keystone XL would allow tar sands production to increase by approximately 800,000 bpd more than it would under the No Expansion alternative between 2020 and 2030.[69] *Id.* at 117. (As explained throughout these comments and in our comments of June 6, 2011 at 40-52, 800,000 bpd underestimates the effect Keystone XL would have on tar sands development).

The graphs on page 8 of the EnSys Report illustrate this projected under different demand scenarios. (Reproduced as figures 1 and 2 below.). Figure 4 (showing the Reference Outlook) and Figure 5 (showing the Low Demand Outlook), both shown below, show a stark difference in production levels if Keystone XL were built versus if it were not built. Together, the graphs show that Keystone XL is expected to increase tar sands production by 750,000 to 900,000 bpd.

Under the Reference Outlook, tar sands production will increase to roughly 3.25 million bpd by 2020 whether or not Keystone XL is built. If Keystone XL is built, production will continue to increase to just under 4.5 million bpd by the year 2030. However, if Keystone XL is not built (and no other pipelines are built), production will increase at a slower pace between 2020 and 2024 and then level out at around 3.6 million bpd by the year 2024. Thus, under the Reference Outlook, Keystone XL will cause a production increase of roughly 900,000 bpd more than under the status quo.

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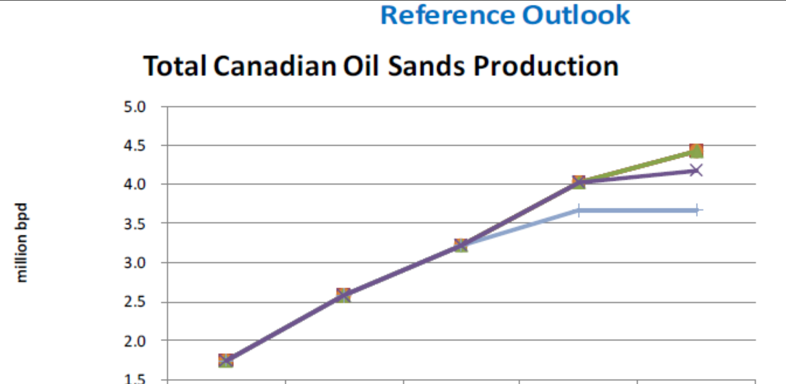
[67] *Id.* at 93.
[68] *Id.* at 31.
[69] Commenters do not accept this number, and believe that Keystone XL a greater increase in tar sands production that will occur sooner than the EnSys Report suggests. *See infra* Section IV.C.3.d.



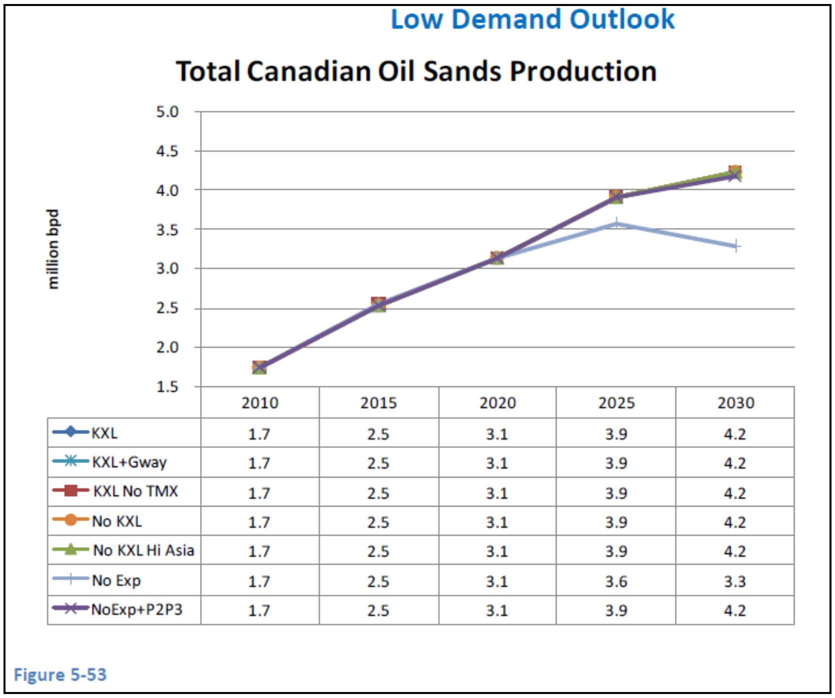
	2010	2015	2020	2025	2030
KXL	1.7	2.6	3.2	4.0	4.4
KXL+Gway	1.7	2.6	3.2	4.0	4.4
KXL No TMX	1.7	2.6	3.2	4.0	4.4
No KXL	1.7	2.6	3.2	4.0	4.4
No KXL Hi Asia	1.7	2.6	3.2	4.0	4.4
No Exp	1.7	2.6	3.2	3.7	3.7
NoExp+P2P3	1.7	2.6	3.2	4.0	4.2

Figure 5-52

Figure 1.

The Low Demand Outlook also shows a significant difference in tar sands production levels between the Keystone XL scenario versus the "No Exp" scenario. Under both scenarios, production will increase to just over 3 million bpd by 2020 regardless of whether Keystone XL is built. If Keystone XL is built, production will then increase until reaching roughly 4.25 million bpd by 2030. Under the No Expansion scenario, however, production will increase at a shallower rate, peak in 2025 at about 3.5 million bpd, and then decrease to roughly 3.25 million bpd by 2030. Thus, under both the Reference Outlook and the Low Demand Outlook, Keystone XL will cause around a nearly million bpd increase in tar sands production levels higher than what would occur under the status quo.[70]

[70] *Id.*



	2010	2015	2020	2025	2030
KXL	1.7	2.5	3.1	3.9	4.2
KXL+Gway	1.7	2.5	3.1	3.9	4.2
KXL No TMX	1.7	2.5	3.1	3.9	4.2
No KXL	1.7	2.5	3.1	3.9	4.2
No KXL Hi Asia	1.7	2.5	3.1	3.9	4.2
No Exp	1.7	2.5	3.1	3.6	3.3
NoExp+P2P3	1.7	2.5	3.1	3.9	4.2

Figure 2.

Since EnSys prepared its report in 2010, the State Department has undertaken additional studies and gone to great lengths to explain why the "status quo" is unlikely to occur. For example, DOE hired EnSys to prepare an additional report in 2011, which "concluded that even if there were no new pipelines added beyond those existing in 2010, rail supported by barge and tanker, as well as expansions to refining/upgrading in Canada, could accommodate projected oil sands production."[71] The DSEIS reasons that if no new pipeline infrastructure is built, transport of tar sands crude oil by rail will allow unfettered growth in tar sands extraction.[72] The undersigned groups disagree with those assessments and have explained why those conclusions are arbitrary and capricious. *See* Section II.D.1.

Regardless of its likelihood, this analysis of what the "status quo" scenario might mean in terms of levels of tar sands production is entirely missing from the latest DSEIS. The State Department has not attempted to update the "status quo" projections from the 2010 EnSys Report, or include any other analysis of the status quo scenario other than a single conclusary paragraph. Therefore, it is impossible to compare the effects of Keystone XL against the status quo "baseline."

d. The Department's Analyses of the "Rail/Pipeline Scenario" and "Rail/Tanker Scenario" are Arbitrary and Capricious

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[71] DSEIS, at 1.4-6.
[72] *Id.*

The DSEIS' analysis of the "rail/pipeline scenario" and "rail/tanker scenario" are arbitrary and capricious. Courts have found "no action" alternatives to be inadequate where the analysis is based on "false data or unexplained assumptions." *Van Abbema v. Fornell*, 807 F.2d 633 (7th Cir. 1986); *see also*, *N.C. Wildlife Federation v. N.C. Department of Transportation*, 677 F.3d 596 (4th Cir. 2012). Courts "not infrequently find NEPA violations when an agency miscalculates the 'no build' baseline or when the baseline assumes the existence of a proposed project." *N. Carolina Wildlife Fed'n v. N. Carolina Dept. of Transp.*, 677 F.3d 596, 603 (4th Cir. 2012); *Friends of Yosemite Valley v. Kempthorne,* 520 F.3d 1024, 1037–38 (9th Cir.2008). Glaring errors in an EIS can render them invalid, even if they involve matters of technical expertise- *NRDC v.U.S. Forest Service*, 421 F.3d 497; or if important information has been overlooked or not obtained, *Sierra Club and Friends of the Earth v. Norton*, 207 F. Supp. 2d 1310 (S.D. Ala. 2002); or if there is some suggestion of "bad faith" or falsification that may have prejudiced the analysis, *N.C. Wildlife Federation v. N.C. Department of Transportation*, 677 F.3d 596. One factor that must be considered is whether the degree of uncertainty is adequately acknowledged and factored into the analysis.

Here, there is a very high degree of uncertainty involved in the DSEIS' "no action" that is not acknowledged. Furthermore, the "rail/pipeline scenario" and "rail/tanker scenario" alternatives are unlikely to occur. Independent market analysis by The Goodman Group concludes that there are "serious impediments to both pipeline expansion and crude by rail."[73]

In addition, the analysis of these "no action" scenarios is arbitrary and capricious and unrealistic because it assumes that the same market for WCSB will exist for the indefinite future. One of the State Department's criteria for selecting alternative "no action scenarios was timing- it looked at "[t]ransport scenarios that could be operational in approximately the same time frame as the proposed Project (e.g., late 2010s)."[74] Thus, the DSEIS dismisses the "status quo" by reasoning that some other transport option will develop before 2020 that will allow additional tar sands crude to get to market.

However, the DSEIS does not discuss potential changes to the market for WCSB crude oil that might occur in that time period if Keystone XL is denied. For example, if the State Department chooses the "no action" alternative and the status quo remains, it is likely that major changes to the oil market will be implemented in coming years that would reduce the demand for WCSB crude oil, such as: new technologies, fuel efficiency requirements, alternative sources of energy, increasing supply of domestic oil, etc. In other words, if Keystone XL is not built, the demand for WCSB crude may fall before another alternative is feasible, casting doubt on whether those other alternatives would actually occur. Rather than assume that other ways of transporting WCSB crude oil to market will definitely come online in absence of Keystone XL,

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[73] *See* Appendix I: Ian Goodman et. al., Report evaluating the adequacy of the Keystone XL (KXL) Draft Supplemental Environmental Impact Statement.
[74] DSEIS, at 5.1-2.

the State Department should have analyzed the likelihood of those projects actually occurring based on potential market conditions as they might exist several years from now.

e. The DSEIS Improperly Assumes that Additional Infrastructure Will be Built

Furthermore, the State Department cannot assume that these other infrastructure projects will be built or otherwise come to fruition in order to avoid analyzing the effects of Keystone XL. Courts have held that "statements that the indirect and cumulative effects will be minimal or that such effects are inevitable are insufficient under NEPA." *Ctr. for Biological Diversity v. U.S. Dept. of Interior*, 623 F.3d 633, 640 (9th Cir. 2010) (BLM violated NEPA where its EIS assumed the impacts would be the same under every alternative, and therefore failed to provide a comparative analysis of the environmental impacts of the action as compared to the no action alternative); *Davis v. Mineta*, 302 F.3d 1104, 1122–23 (10th Cir.2002); *see also State Farm*, 463 U.S. at 43, 103 S.Ct. 2856.

In other words, an agency may not ignore its duty to examine a project's impacts by "presenting the result as a *fait accompli* incorporated into an environmental baseline. *See Swan View Coalition v. Barbouletos*, No. 6–73–M, 2008 WL 5682094, *16, 2008 U.S. Dist. LEXIS 56677 *45–46 (D.Mont.2008); *League to Save Lake Tahoe v. Tahoe Reg'l Planning Agency*, 739 F. Supp. 2d 1260, 1276 (E.D. Cal. 2010) *aff'd in part, vacated in part, remanded*, 469 F. App'x 621 (9th Cir. 2012).

In *Sierra Club v. United States Dep't of Transp.*, 962 F.Supp. 1037 (N.D.Ill.), the court stated that:

> [T]he final impact statement in this case relies on the implausible assumption that the same level of transportation needs will exist whether or not the tollroad is constructed. In particular, the final impact statement contains a socioeconomic forecast that assumes the construction of a highway such as the tollroad and then applies that forecast to both the build and No–Build alternatives. The result is a forecast of future needs that only the proposed tollroad can satisfy. As a result, the final impact statement creates a self-fulfilling prophecy that makes a reasoned analysis of how different alternatives satisfy future needs impossible.

Id. at 1043.

In *N. Carolina Alliance for Transp. Reform, Inc. v. U.S. Dept. of Transp.*, 151 F. Supp. 2d 661, 690 (M.D.N.C. 2001), the agency avoided an analysis of the impacts of a highway project by reasoning that the project "would simply accommodate already existing growth or growth that was bound to occur whether or not the [highway] was constructed." The court held that "the use of the same statistical data to analyze both the Build and No–Build alternatives fails to provide a reasonable basis for comparison of these alternatives." *N. Carolina Alliance for Transp. Reform, Inc. v. U.S. Dept. of Transp.*, 151 F. Supp. 2d 661, 690 (M.D.N.C. 2001).

The DSEIS violates NEPA because it assumes that tar sands development and corresponding GHG emissions will increase at the same rate regardless of whether Keystone XL is built. While it is possible that alternative pipelines or rail projects would be built in absence of Keystone XL, the State Department cannot assume that any will be built so as to avoid analyzing Keystone XL's impacts. While these other speculative projects may occur, and may have similar impacts on tar sands development, they do not negate the impacts that Keystone XL would have, and Keystone XL is the only project that is currently in front of the State Department.

In fact, alternative pipeline and rail scenarios would undergo their own environmental reviews under federal, state, and local laws. Many of these alternative scenarios have already faced stiff opposition, and are far from inevitable. The DSEIS entirely failed to discuss the permitting requirements and other obstacles that these other alternatives face. Instead, it assumes that some alternative will proceed because there is sufficient demand for WCSB crude oil in the Texas Gulf Coast. Thus, the DSEIS is arbitrary and capricious.

f. The Analysis of the Alternative No Action Scenarios Is Insufficient

In cases such as this, where the rejection of a project would lead to reasonable foreseeable alternatives being built, an agency must analyze the impacts of those alternatives:

> The second interpretation of "no action" is illustrated in instances involving federal decisions on proposals for projects. "No action" in such cases would mean the proposed activity would not take place, and the resulting environmental effects from taking no action would be compared with the effects of permitting the proposed activity or an alternative activity to go forward.
>
> Where a choice of "no action" by the agency would result in predictable actions by others, this consequence of the "no action" alternative should be included in the analysis. For example, if denial of permission to build a railroad to a facility would lead to construction of a road and increased truck traffic, the EIS should analyze this consequence of the "no action" alternative.

"Forty Most Asked Questions on the National Environmental Policy Act Regulations", 46 Fed. Reg. 18026 (1981). In creating the two alternative "no action" scenarios, the DSEIS attempts to comply with this obligation. However, the analysis falls short.

Nowhere in the discussion of the impacts of the "rail/pipeline scenario" or the "rail/tanker scenario" does the DSEIS discuss the on-the-ground impacts of increased tar sands development or the attendant increases in GHG emissions. The DSEIS uses these two "no action" scenarios in an attempt to demonstrate that tar sands development will increase at the same rate regardless of whether Keystone XL is built. Even if that were true, the direct, indirect, and cumulative impacts of those alternative actions (*i.e.*, increased tar sands development) must be analyzed. Here, the State Department ignored those impacts altogether.

Similarly here, the evidence before the State Department demonstrates that Keystone XL would be the only current means to ship increased amounts of tar sands crude to new market and thus allow tar sands production to increase. Keystone XL and tar sands production are necessary links in the chain of extraction, shipping and refining increased amounts of tar sands. While the EnSys report speculates that other pipelines projects may be built in the future in the absence of Keystone XL, those projects are far from certain to occur and thus are not "current" alternatives. While these other speculative projects may also cause an increase in tar sands production if they do proceed, that does not negate the fact that Keystone XL would cause production to increase.

It is unreasonable for an agency to assume that alternative projects would result in the same impacts if those other projects would have to undergo similar permitting. *Ctr. for Biological Diversity v. U.S. Dept. of Interior*, 623 F.3d 633, 647 (9th Cir. 2010). In *Friends of Yosemite Valley v. Scarlett*, 439 F.Supp.2d 1074, 1037–38 (E.D.Cal.2006), the court found an EIS invalid because every alternative it considered, including the no-action alternative, assumed the existence of projects that required agency authorization but that the agency had not yet validly authorized. *Id.* at 1037–38; *see also League to Save Lake Tahoe v. Tahoe Reg'l Planning Agency,* 739 F. Supp. 2d 1260, 1275-76 (E.D. Cal. 2010) *aff'd in part, vacated in part, remanded*, 469 F. App'x 621 (9th Cir. 2012).

2. The DSEIS' Analysis of Route Alternatives in Nebraska Is Flawed

a. The State of Nebraska's Approval of the Nebraska Reroute Was Flawed and Must Be Closely Examined

i. Background on Nebraska's flawed reroute process

The State Department "paused" in the process of evaluating TransCanada's application for Keystone XL in November 2011 largely because of concerns about its potential impact on the Sandhills and the Ogallala Aquifer in the State of Nebraska. Since this was the primary basis for delay, the entire process related to the State of Nebraska should be given strict scrutiny. In particular, TransCanada's interactions with officials and citizens of the State of Nebraska need close examination in order to determine whether the activities conducted since November 2011 pass muster in terms of issues related to impacts on the Sandhills and Ogallala Aquifer, whether legal rights of Nebraskans have been violated, whether the normally accepted standards of representative government have been violated and whether the results meet appropriate procedural and scientific standards.

Beginning in approximately May 2010 and continuing through November 2011, TransCanada's proposal to build Keystone XL created controversy in Nebraska. United States Senator Mike Johanns opposed the proposed route through the Sandhills and objected to TransCanada's repeated threats of eminent domain against Nebraska landowners. In the summer of the 2011 State Senator Ken Haar proposed a special session of the Legislature to deal with the issue of TransCanada's route through the Sandhills.

On August 31, 2011, Governor Heineman sent a letter to then-Secretary of State Hillary Clinton asking that the Keystone XL permit be denied because it threatened the Ogallala Aquifer. In that letter Governor Heineman stated: "I am opposed to the proposed route of this pipeline. The Final Environmental Impact Statement compares a potential spill in the Sand Hills region to a 1979 Bemidji, Minnesota spill and concludes that the 'impacts to shallow groundwater from a spill of similar volume in the Sand Hills would affect a limited area of the aquifer around the spill site.' I disagree with this analysis and I believe that the pipeline should not cross a substantial portion of the Ogallala Aquifer."

In the late summer and fall of 2011 TransCanada attempted to prevent the Legislature from being called into special session. They hired a lobby firm, Radcliffe and Associates, for the express purpose of lobbying against a special session and floated several memos that indicated that any legislation related to changing the route would be unconstitutional and result in millions, perhaps hundreds of millions of dollars in legal liability for the State of Nebraska.

In mid-October 2011, TransCanada officials met with the Speaker of the Legislature, Mike Flood and State Senators Kate Sullivan, Annette Dubas and Chris Langemeier. As an outcome of that meeting Alex Pourbaix of TransCanada sent a letter dated October 18, 2011 in which he stated "it is impossible for us to move the route to avoid the Sandhills." In that letter Pourbaix offered several "measures for your consideration" that appeared intended to prevent the special session to require the pipeline to be moved from the Sandhills, although it appears unlikely that Speaker Flood, as a member of the Legislature, had legal authority to act on behalf of the State of Nebraska in response to TransCanada's offer.

On October 24, 2011, Governor Heineman called the Legislature into Special Session beginning November 1, 2011. Legislation was introduced and hearings were held. Proponents of legislation granting the State authority over the route of oil pipelines far outnumbered opponents. TransCanada opposed every piece of legislation.

On November 10, 2011 the State Department announced that it would delay the review process because of concerns about the about "the proposed route through the Sand Hills area of Nebraska, which was one of the most common issues raised." In addition the statement provided: "Taken together with the national concern about the pipeline's route, the Department has determined it is necessary to examine in-depth alternative routes that would avoid the Sand Hills in order to move forward with a National Interest Determination for the Presidential Permit."

On November 14, 2011 TransCanada officials and several Nebraska State Senators appeared at a press conference in which TransCanada announced that it would avoid the Sandhills in return for passage of LB 4, which provided an expedited process for their application which would be reviewed by the Nebraska DEQ. In order to avoid issues of conflict-of-interest, the State of Nebraska would pay for the review. As part of that agreement, TransCanada would also support the passage of LB 1, which would grant authority over the routing of oil pipelines to the public service commission. LB 1 had a number of criteria which must be met before the route could be approved, including a finding that the applicant had established that its route was in the public interest. The Legislature passed both LB 1 and LB 4 and both were signed into law on November 22, 2011.

On December 2, 2011 Alex Pourbaix appeared before a hearing in the House of Representatives in support of legislation that would further expedite the process. This provision was attached to the Temporary Payroll Tax Cut Continuation Act of 2011, which required the State Department to approve or deny the application within 60 days. On January 18, 2012 the State Department denied the application because in President Obama's words, the legislation "prevented a full assessment of the pipeline's impact, especially the health and safety of the American people, as well as our environment."

On January 19, 2012, LB 1161 was introduced in the Nebraska Legislature. It sought to put in place a review of TransCanada's new application by the Nebraska DEQ, similar to LB 4 from the special session. However, it contained a new provision relating eminent domain for oil pipeline companies subject to the act, granting them eminent domain authority immediately upon approval of the route by the Governor.

The Nebraska DEQ and TransCanada provided the only witnesses in support of LB 1161. Mike Linder, the Director of NDEQ, Robert Jones, vice-president of TransCanada and Jim White, representing TransCanada's legal division appeared in support of LB 1161. It is unusual for the director of an agency to appear in support of legislation granting that agency authority in a particular area. TransCanada officials stated that TransCanada would be the only company that would use the authority granted under LB 1161. Fourteen individuals testified in opposition to LB 1161.

The Nebraska Sierra Club repeatedly raised issues about the constitutionality of LB 1161, beginning at the hearing on the bill, and included a legal memo provided to the members of the Natural Resources Committee of the Legislature. LB 1161 was rewritten several times before its final form was presented to the Legislature on April 5, 2012. The Nebraska Legislature's rules require all legislation to have a public hearing. Generally, when legislation is materially altered by new material, that legislation will be submitted for hearing prior to the Legislature acting on it. In the case of LB 1161, the Legislature adopted a version substantially different from any previous one after approximately 20 minutes of debate and with no public hearing on the new language. LB 1161 has since been challenged in court based on constitutional grounds including the following: (1) It is unconstitutionally vague; (2) It grants authority to grant eminent domain to the Governor without any standards; (3) It grants pipeline routing review to the NDEQ and approval to the Governor when such authority is constitutionally held by the Public Service Commission; (4) It fails to provide a process for legal review. The case, *Thompson v. Heineman*, is likely to be heard on the merits in the summer of 2013. If LB 1161 is declared invalid, the Governor's decision to approve the pipeline route would be thrown out.

After enactment of LB1161, no clear process or standards for the route approval were established by NDEQ despite many requests by Nebraska citizens to formally weigh-in on the process. NDEQ's evaluation of the proposed route appears to be a compilation of information supplied by TransCanada's contractor HDR and studies by other oil industry interest groups.

ii. TransCanada's violations of state and federal law

TransCanada has repeatedly engaged in activities which appear to be serious violations of law. Neb. Rev. Stat. section 81-1508.01(e) provides that the following is a violation of law punishable as Class IV felony: "Making any false statement, representation, or certification in any application, label, manifest, record, report, plan, or other document required to be filed or maintained by the Environmental Protection Act, the Integrated Solid Waste Management Act, or the Livestock Waste Management Act or the rules or regulations adopted and promulgated pursuant to such acts." Section 81-1508.02(c) provides civil penalties for the following: "To make any false statement, representation, or certification in any application, label, record, report, plan, or other document required to be filed or maintained by such acts, rules, or regulations."

As previously indicated, TransCanada offered a much larger version of the Sandhills in their original application to the State Department. They also officially opposed the use of the EPA eco-regions map when it was presented to the Legislature. This information should have been included in their application to NDEQ. The fact that TransCanada failed to disclose their official positions regarding the two maps appears to be a "false representation" as part of an application and therefore a violation of State law.

In addition, 42 U.S.C. § 1983 provides as follows: "Every person who, under color of any statute, ordinance, regulation, custom, or usage, of any State or Territory or the District of Columbia, subjects, or causes to be subjected, any citizen of the United States or other person within the jurisdiction thereof to the deprivation of any rights, privileges, or immunities secured by the Constitution and laws, shall be liable to the party injured in an action at law, suit in equity, or other proper proceeding for redress." The right to own property is a fundamental right, enshrined in the Constitutions of the United States and the State of Nebraska. The Fifth Amendment to the US Constitution states in relevant part as follows: "No person shall …. be deprived of life, liberty, or property, without due process of law; nor shall private property be taken for public use, without just compensation."

In this case, TransCanada is obtaining private property from US citizens under color of state law for a private for-profit purpose. TransCanada has repeatedly sent letters and made oral representations to Nebraska landowners stating that TransCanada would commence eminent domain proceedings if the landowner did not grant an easement for their pipeline within a certain amount of time, usually within 30 days. The letters cite as authority Neb. Rev. Stat. section 57-1101, which provides as follows: " Any person engaged in, and any company, corporation, or association formed or created for the purpose of, transporting or conveying crude oil, petroleum, gases, or other products thereof in interstate commerce through or across the State of Nebraska or intrastate within the State of Nebraska, and desiring or requiring a right-of-way or other interest in real estate and being unable to agree with the owner or lessee of any land, lot, right-of-way, or other property for the amount of compensation for the use and occupancy of so much of any lot, land, real estate, right-of-way, or other property as may be reasonably necessary for the laying, relaying, operation, and maintenance of any such pipeline or the location of any plant or equipment necessary to operate such pipeline, shall have the right to acquire the same for such purpose through the exercise of the power of eminent domain. … The procedure to condemn property shall be exercised in the manner set forth in sections 76-704 to 76-724."

Section 76-704.01 provides: "(7) If approval of any other agency is required the condemner should set forth the approval in writing of such agency." Since TransCanada has never had the approval of the State Department to construct Keystone XL, this information should have been disclosed in any materials provided to landowners. In addition, § 76-710.04 provides as follows: "(1) A condemner may not take property through the use of eminent domain under sections 76-704 to 76-724 if the taking is primarily for an economic development purpose." Although there is an exception which allows pipeline companies to exercise eminent domain, this statute provides a clear statement that the public policy of the State of Nebraska is opposed to the use of eminent domain for private gain.

Finally, the DSEIS fails to discuss TransCanada's extensive use of eminent domain required for this pipeline, both in Nebraska and all other states along the pipeline route. The fact that thousands of private landowners along the route will either lose their private property rights to a foreign corporation, either through eminent domain or by being pressured into signing an agreement, is a significant effect of this project that has not been analyzed under NEPA.

iii. Improper actions by Nebraska officials which have prevented an objective review

Nebraska case law requires an impartial hearing before an impartial board on administrative matters. *See e.g.*, *Crown Products Co. v. City of Ralston*, 253 Neb. 1 (1997). There have been numerous activities by State officials which have prevented an impartial review in this process. Bill Sydow, the executive director of the Nebraska Oil and Commission made numerous public statements supporting the proposed pipeline and appeared in advertisements promoting the pipeline. These statements and advertising would appear to indicate that the State of Nebraska supports Keystone XL and intended to sway public opinion related to the pipeline. In addition, some of the statements appear to be materially false and misleading such as the following which appeared in a full page advertisement in the Lincoln Journal Star on November 6, 2011, the first day of hearings on legislation during the special session: "I want you to know: It is impossible for crude oil to contaminate the Ogallala Aquifer." This statement is false and misleading, since there are numerous documented instances of crude oil contaminating aquifers, including the well-documented Bemidji spill which has still not been completely remediated more than 30 years later.

Governor Heineman made numerous public pronouncements that implied the pipeline route should be approved prior to his actual approval of the route. His statement at the time of signing LB 1161 into law implies that it should be approved by framing the issue in the terms used by pipeline advocates, jobs and energy security. "Nebraska will move forward on the review process of the proposed Keystone XL pipeline and any future pipelines that will create jobs and reduce U.S. dependence on Middle Eastern oil," said Gov. Heineman. "The review process is a top priority for Nebraska."[75]

The fact the Governor appoints the members of the Environmental Quality Council (EQC) and the Governor appoints the director of the NDEQ means that his statements using the messaging of pipeline proponents contaminated the review process and prevented an impartial review. Further, as previously noted, the fact the NDEQ executive director supported LB 1161 in conjunction with TransCanada officials was unusual since it granted authority over the review process to NDEQ. The fact that the NDEQ director was the only Nebraskan to testify in support of LB 1161 also raises significant questions about the NDEQ's ability to objectively review the route application.

iv. <u>NDEQ's review of the Nebraska route has largely been influenced by oil industry interests</u>

Review of the new Nebraska route is flawed due to clear conflicts of interest that exist by choosing HDR as the contractor that prepared the route review. That is because HDR was simultaneously a consultant on a joint project sponsored by TransCanada and Exxon Mobil as well as having numerous other ties to tar sands and TransCanada. In addition, HDR relied on biased information from companies like the Perryman Group for an economic analysis of the pipeline. The Perryman Group was hired by the American Petroleum Institute and TransCanada to prepare the one-sided economic view of the project. Indeed, if studies from biased entities such as the Perryman Group and Consumer Energy Alliance are used in this critical process, then accepting reports from public interest groups and academic institutions, not tied to the oil industry, must be considered to ensure a balanced assessment.

v. <u>NDEQ used flawed information in its review of the Nebraska route</u>

Further, NDEQ's analysis was fundamentally flawed because it referred to the substance to be transported through the Keystone XL pipeline as "crude oil," which is not the case. Diluted bitumen and other bitumen-derived substances, which would be transported through the pipeline are quite different from conventional crude in both physical and chemical ways. As described in II.D.3, diluted bitumen is highly corrosive, unstable and toxic. At the time NDEQ conducted its approval it did not have complete knowledge about the specific ingredients, chemicals, and compounds to be transported through the pipeline, and the potential impacts on Nebraska natural resources. NDEQ also was working off of outdated oil spill response plans and had no information about TransCanada's capacity to ensure that proper equipment and trained personnel would be readily available to respond to spills.

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[75] http://www.governor.nebraska.gov/news/2012/04/17_pipline.html

Moreover, the ecoregion map used to define the Sandhills was inadequate and inconsistent with other maps, including the USGS map used by TransCanada in its application to the State Department and used as part of the official Keystone XL DSEIS. Moreover, no explanation has ever been given describing why the new route could not parallel the Keystone 1 pipeline, which avoids the Sandhills. NDEQ failed to rely on science and studies of the sandy soils and water levels in approving the pipeline.

vi. NDEQ failed to assure ongoing state oversight and accountability

Nebraska's approval of the new route did not provide any assurances that the state would have further oversight or enforcement authority to ensure that mitigation measures and the Construction, Mitigation and Reclamation Plan are fully implemented by TransCanada. This is especially troubling for Nebraska landowners who stand to be adversely affected by construction and operation of the pipeline.

Indeed, the NDEQ analysis of the new route was flawed every step of the way. The public had little opportunity to formally weigh in. NDEQ's analysis failed to seek input from experts not tied to TransCanada or other oil industry interests. As a result, NDEQ approved a new route largely unchanged from the first proposal – it does not avoid the Sandhills, sandy soil or the Ogallala Aquifer.

b. The New Route through Nebraska Fails to Avoid the Sandhills and Ogallala Aquifer

The NDEQ review of the new route failed to accomplish its main goal of rerouting the pipeline away from the Sandhills. Despite Governor Heineman's demands to reroute the pipeline to avoid the Ogallala Aquifer, the new route proposed by TransCanada still recklessly crosses the Sandhills, sandy soils, and the Ogallala Aquifer.

i. The Sandhills

Given the importance of the Sandhills issue to the State Department's decision to wait until the Nebraska review process was completed, it deserves strict scrutiny. TransCanada agreed to avoid the Sandhills, but the Nebraska Legislature did not adopt any definition of the Sandhills. LB 5, introduced in the 2011 special session contained an avoidance area that included EPA eco-region 44, which has since been adopted as the Sandhills boundary by the NDEQ. However, LB 5 was not advanced by the Legislature and died at the end of the special session. Neither LB 4 nor LB 1161 have any definition of the Sandhills. Although there was discussion of a map during floor debate on LB 4, it was never made a part of the record and was never officially adopted by the Legislature. This map was not adopted by the Legislature, and there was no other authority by which it was adopted. There is a substantial body of Nebraska caselaw that holds that the Legislature cannot delegate its legislative authority and that standards for administrative agencies "must be reasonably adequate, sufficient, and definite for the guidance of the agency in the exercise of the power conferred upon it and must also be sufficient to enable those affected to know their rights and obligations." *Kwik Shop v. City of Lincoln*, 243 Neb. 178 (1993).

Therefore, since the Legislature did not adopt a version of the Sandhills, the NDEQ exceeded its authority by adopting the map that it chose.

Secondly, TransCanada's own behavior is an important key in defining the Sandhills. TransCanada offered a map to the State Department in 2008 which defined the Sandhills as being considerably larger than the EPA map being utilized by the NDEQ. In addition, TransCanada opposed the EPA eco-regions map when it was proposed to the Legislature in LB 5, stating, among other things, "it's quite clear that the concern is for the aquifer, for the Sandhills." During floor debate on LB 4, Speaker Mike Flood acknowledged that there was no written agreement from TransCanada to avoid the Sandhills. He stated that "TransCanada stood up before the state of Nebraska, through members of the media, and did voluntarily acknowledge that they agreed to move the route of the Keystone XL out of the Sandhills." A statement before the media has no legal status and is not legally enforceable. Therefore, TransCanada should be bound by their official representations; the map they provided to the State Department in 2008 should be the one that is used to define the Sandhills because they indicated that was the boundary before they believed there was a controversy about that issue. Secondly, they cannot use media statements to overcome their official testimony in opposition to the use of the EPA eco-regions map in LB 5.

Third, the factors that caused the State Department to delay the process still exist along the current route; as noted by the NDEQ "the proposed corridor still crosses areas of fragile, sandy soils that are outside the Sand Hills ecoregion but that have surface features very similar to the Sand Hills." In addition, the Natural Resources Commission map notes that soil permeability of the area of the current route is the same as the previous route, more than 50 % rapid permeability.

Fourth, the soils in the area being described as the Sandhills are not subject to strict geographic limits due to the fact that they are highly erodible and have moved about over a period of thousands of years. The following is from Comment and Literature Review on Sediment Transport in the Area bordering the Sandhills in Nebraska, by Risa Madoff, M.S., PhD Candidate, University of North Dakota, Harold Hamm School of Geology and Engineering. "The sand in the Sandhills is not necessarily limited to the geographic boundaries of the landforms, no matter what the scale is."[76] The paper continues: "The soil maps and soil survey data reveal a great deal of compositional variability with depth and with lateral extent."

The paper then comments on soil samples taken by Nebraska residents: "So it is likely that the soil core samples near the locations in question that some Nebraska residents have taken to be analyzed in labs to determine the relative percentages of sand, silt, and clay are representative of the sand content in the soil at a particular location in a county. However, a scientist for the region would need to determine a statistically appropriate number of soil core samples needed to model the areal sand distribution with depth. The soil surveys, listed in the literature review, include discussions about engineering considerations with respect to the soils

[76] Attached as Exhibit 104.

in the respective counties. Those are excellent starting points for an investigation into soil content with depth and interactions with shallow water tables. However, the surveys also claim that site specific studies are required for determinations of appropriateness of man-made structures in a particular area."

In short, accurate, site-specific data needs to be obtained before the State Department draws any conclusions about whether the Sandhills have indeed been avoided and certainly need to be done before there are any conclusions about whether a man-made structure such as a pipeline should be permitted in the area.

Finally, there is objective on-the-ground testimony from the farmers and ranchers who live along the current proposed route. In a court of law, the most credible evidence is that which is derived from the senses. In this case several individuals testified at the hearing in Grand Island that the soil on their land is sandy, that they believe the water table is shallow and they have always understood their land to be in the Sandhills.

Because the issue avoiding of the Sandhills was the primary reason for the delay from November 2011 until the present, the answers to the question of whether the new proposed route should be crystal clear. Instead there is an abundance of evidence, including TransCanada's own map, review of soils data and the on the ground experience that the leads to the conclusion that new proposed route continues to cross the Sandhills. Even giving TransCanada the benefit of the doubt, it is clear that the new proposed route crosses areas that have the same issues with erosion and permeability of soils regardless of how they are defined.

ii. The Ogallala Aquifer

It is clear that the current route goes over extensive areas of the Ogallala Aquifer. No one disputes this. According to TransCanada, "the Ogallala underlies most of the proposed re-route study area." Approximately 35 miles of the proposed pipeline would cross over groundwater less than 20 feet below the surface. The layers above the Ogallala Aquifer are highly permeable and spilled tar sands oil could move quickly through these layers into the aquifer itself, contaminating a crucial water source. The Ogallala Aquifer provides drinking water for millions of Americans and about 30% of the groundwater used for irrigation nationwide. It is clear that a tar sands oil spill above the Ogallala would be a serious issue and this new route does not succeed in avoiding this risk.

As previously noted, in August 2011 Governor Heineman stated: "I am opposed to the proposed route of this pipeline. The Final Environmental Impact Statement compares a potential spill in the Sand Hills region to a 1979 Bemidji, Minnesota spill and concludes that the 'impacts to shallow groundwater from a spill of similar volume in the Sand Hills would affect a limited area of the aquifer around the spill site.' I disagree with this analysis and I believe that the pipeline should not cross a substantial portion of the Ogallala Aquifer."

On January 22, 2013, Governor Heineman made the following statement as part of his letter to Secretary Clinton approving the new proposed pipeline route: "The proposed route avoids the Sand Hills but would cross the High Plains Aquifer, including the Ogallala Group. Impacts on aquifers from a release would be localized and Keystone would be responsible for any cleanup."

It is obvious that Governor Heineman has directly contradicted himself without providing any reasoning for his changed position. As previously noted, LB 1161 provided no standards for NDEQ or Governor to use in determining whether to approve or deny a proposed route. NDEQ made no findings or recommendations regarding the proposed route, and indeed if they had done so, it would have exceeded their authority pursuant to LB 1161. The fact that Governor Heineman made a 180-degree change in his official recommendation regarding approval of the pipeline with no factual basis to support this changed position leads to the inescapable conclusion that his recommendation of approval is arbitrary and capricious and therefore would not withstand legal challenge.

c. The State Department's Analysis of Route Alternatives Is Unlawfully Skewed by the Nebraska State Approval Process

The State of Nebraska's decision on a pipeline route within Nebraska unlawfully usurps the State Department's analysis of route alternatives under NEPA suggests a predetermined outcome.

Nebraska's LB1161 requires that the Governor of Nebraska approve the route of Keystone XL through the state. Any route other than the preferred route chosen by the Governor would violate state law and construction could not proceed. Therefore, the State Department's consideration of Keystone XL route alternatives under NEPA is unlawfully skewed in favor of the preferred route. While the State Department could theoretically choose an alternative other than the preferred route, the reality is none of the other alternatives could occur under state law. As such, LB 1161 presents the State Department with only one real choice of routes.

In addition, the DSEIS fails to acknowledge that its consideration of route alternatives is so limited by LB 116, or adequately discuss the interplay between LB 1161 and the federal NEPA process. By failing to disclose this important aspect of the problem, the DSEIS is effectively considering route alternatives that could not actually occur because they would violate state law. Thus, the analysis of route alternatives is fatally flawed.

3. The DSEIS Does Not Adequately Analyze the "Keystone Corridor Option 2" Alternative

In our previous comments, we explained that it was arbitrary and capricious for the State Department to use the Morgan, Montana border crossing as a screening criterion, and to analyze only alternatives that would cross the U.S.-Canada border at that point.[77] In response, the State Department included the "Keystone Corridor Option 2" route alternative that would use the same border crossing and right-of-way as the Keystone I pipeline. However that alternative was not adequately analyzed and was improperly eliminated from consideration.

NEPA requires the State Department to rigorously explore and objectively evaluate all reasonable alternatives, or alternatives that meet the purpose and need for the proposed action as defined by the agency in the EIS.[78] The primary purpose and need for Keystone XL as defined in the DSEIS "to provide the infrastructure to transport Western Canadian Sedimentary Basin (WCSB) crude oil from the border with Canada to existing pipeline facilities near Steele City, Nebraska, for onward delivery to Cushing, Oklahoma, and the Texas Gulf Coast area."[79]

The Keystone Corridor Option 2 alternative meets the primary purpose and need, would have the shortest length within the U.S., would impact the least amount of land, and would largely avoid sensitive resources such as the Ogallala Aquifer and the Sand Hills. DSEIS, at 2.2-45. As such, it appears to be the most logical and attractive option.

However, the DSEIS states that it eliminated Keystone Corridor Alternative Option 2 for three reasons: (1) it is 303 miles longer, including the Canadian portion; (2) it would require an additional 350 mile pipeline to access Bakken crude; and (3) it would require 42 aboveground facilities compared to 59 for the proposed route.[80]

None of these are legitimate reasons for elimination that would outweigh this shorter and less-impactful route. First, the fact that the overall pipeline would be 303 miles longer should not preclude this option from consideration. As acknowledged, this option would follow existing Keystone I rights-of-way (including the Canadian portion), so the environmental impacts would be less, not more, as the DSEIS asserts. Incidentally, the State Department does not evaluate the impacts of Keystone XL in Canada in any meaningful way, so it is arbitrary and capricious for it to no summarily dismiss this option based on unanalyzed environmental impacts in Canada.

Second, the "Keystone Corridor Option 2" should not be dismissed because it would require an additional pipeline to access Bakken crude. Accessing Bakken crude oil is a secondary "purpose" of Keystone XL rather than a primary purpose. The State Department should analyze what alternatives would be available to get Bakken crude oil to markets if Keystone XL were

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[77] *See* SEIS comments, Ex. 2, at 11-15. The DSEIS fails to address our concerns regarding the State Department's insufficient consideration of alternative routes, so those issues remain unresolved and our comments are incorporated by reference hereto.
[78] *Natural Resources Defense Council, Inc. v. U.S. Forest Service*, 634 F.Supp.2d 1045, 1059 E.D.Cal.,2007; *'Ilio'ulaokalani Coal. v. Rumsfeld*, 464 F.3d 1083, 1097 (9th Cir. 2006) (citing *Nw. Coalition for Alternatives to Pesticides (NCAP) v. Lyng,* 844 F.2d 588, 591-592 (9th Cir.1988)).
[79] DSEIS, at 1.3-1.
[80] *Id.* at 2.2-47 and 48.

farther east, including route alternatives for a pipeline link to Keystone XL, rather than simply dismissing this favorable route out of hand.

Finally, the fact that the "Keystone Corridor Option 2" would require *fewer* aboveground facilities than the preferred route should be grounds for favoring this route rather than dismissing it. The State Department fails to explain why it believes that more aboveground facilities are required.

The State Department fails to discuss whether the border crossing at Morgan, Montana remains a screening criterion. While the State Department removed much of its previous language regarding "control points," a footnote on Figure 2.2.4-1 suggests that it is still refusing to seriously consider route alternatives that would require TransCanada to change the Canadian portion of the route: "The Canadian government has approved and permitted a route from Hardesty to the proposed border crossing. A new border crossing location would require new routing, approvals, and permits in Canada."[81]

The State Department's continued use of Morgan, Montana as the only border crossing option is arbitrary and capricious and improperly limits the alternatives analysis. The statement of purpose and need for Keystone XL does not include the need to use a route approved by Canadian regulators in a process that did not consider environmental impacts in the United States. Therefore, an otherwise arbitrary criterion which screens reasonable alternatives on this basis is impermissible. Under NEPA's reasonable alternatives provision, the State Department "may not define the objectives of its action in terms so unreasonably narrow that only one alternative from among the environmentally benign ones in the agency's power would accomplish the goals of the agency's action, and the EIS would become a foreordained formality."[82] The Canadian portion of the pipeline has not been built. The approval of a route from Hardesty, Alberta to Morgan, Montana by Canadian regulators at the National Energy Board (NEB) does not suggest that a route using another border crossing facility is technically infeasible. On the contrary, in 2007 the NEB approved another route from Hardesty, Alberta to Pembina, North Dakota for the Keystone I pipeline.[83] Finally, the NEB did not consider environmental impacts in the United States or consult with federal agencies when permitting a Hardesty, Alberta to Morgan, Montana. The approval of a border facility in Morgan, Montana by the Canadian government does not diminish the State Department's responsibilities under NEPA to rigorously explore and objectively evaluate all reasonable alternatives. [84]

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[81] Figure 2.2.4-1, at 2.2-43.

[82] *National Parks & Conservation Ass'n v. Bureau of Land Management*, 606 F.3d 1058, 1070 (9th Cir. 2010).

[83] http://www.transcanada.com/3115.html

[84] 40 C.F.R. § 1502.14(a). In addition, "for alternatives which were eliminated from detailed study, briefly discuss the reasons for their having been eliminated…; [and] [d]evote substantial treatment to each alternative considered in detail including the proposed action so that reviewers may evaluate their comparative merits." *Id*.

4. <u>The DSEIS Fails to Consider Increased Renewables and Cleaner Fuel Sources as a Reasonable Alternative</u>

The State Department's narrow selection of alternatives looks only at a range of oil transport and route alternatives, relying entirely on the assumption that increased tar sands importation will occur regardless of whether the proposed pipeline is constructed. However, a large-scale expansion of pipeline and refinery capacity to transport heavy crude from the Canadian tar sands to the US reflects a feverish rush of tar sands investment and development in Canada that is dependent on a parallel increase in demand in the United States. The corresponding push to expand tar sands oil delivery and refining systems in the US[85] comes at a time when the nation is looking to reduce its dependence on fossil fuels, expand the development of renewable fuels and reduce its emissions of harmful greenhouse gases.[86] Surprisingly, the DSEIS rejects consideration of the role of renewable fuels sources in its alternatives analysis and does not take a hard look at the global warming implications of this expanded pipeline network.

The DSEIS' rejection of the "Alternative Energy Sources and Energy Conservation" alternative and refusal to fully evaluate this alternative is based on false premises. "Outlooks for world and United States demand for crude oil indicate that even if there were a substantial reduction in United States consumption of crude oil (and/or relatively flat world-wide consumption), the market demand in PADD 3 that is driving the development of the proposed Project would likely remain." DSEIS at 2.2-36. The DSEIS is flawed because it bases the alleged demand for the project on the exclusive capabilities of Gulf area refineries to process heavy sour crudes, rather than on overall U.S. demand for fuels in light of federal initiatives to reduce oil consumption and reduce total greenhouse gas emissions. As described above, the NEPA analysis cannot serve as the basis of a National Interest Determination if it narrowly defines the need for the project based on demand created by refiner decision making. Further, the DSEIS lacks evidence showing that reliance on WCSB oil – among the most carbon intensive sources of oil – will be the only way to meet U.S. demand; the DSEIS provides no substantial support for rejecting full consideration of alternative, cleaner fuels to meet U.S. demand. Indeed, premising the need for the proposed project on refiner demand is not in the best interest of the American people who will largely pay the costs of piping this oil through our nation's heartland while reaping very few, if any, benefits.

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[85] See the maps prepared by Oil Sands Truth depicting tar sands exports and pipeline expansions projected for 2015 and 2030 based on data provided by NEB, Enbridge, Imperial Oil, TransCanada Pipelines, and the State of Alaska. Available at <u>http://oilsandstruth.org/maps</u> and attached hereto as Exhibit 13.

[86] *See, e.g.*, the Obama-Biden Comprehensive New Energy for America Plan which includes investment in "a clean energy future," improving energy security by "sav[ing] more oil than we currently import from the Middle East and Venezuela combined," renewable portfolio standards for utilities, and an "economy-wide cap-and-trade program to reduce greenhouse gas emissions 80 percent by 2050." Available at <u>http://www.whitehouse.gov/agenda/energy_and_environment/</u> and attached hereto as Exhibit 14. It is particularly noteworthy that the plan does not look to replace Middle Eastern and Venezuelan oil with oil from Canada, but instead proposes within 10 years to eliminate US demand for that oil.

The DSEIS is fatally flawed because it fails to fully evaluate a cleaner fuels alternative, and a national interest determination for a project that implicates U.S. oil supply cannot be made in the absence of full consideration of such an alternative, in light of national policy goals of reducing oil dependence and the real and catastrophic impact that climate change has and will continue to have on the American people. As such, the DSEIS should either be revised and reissued for public comment or, preferably, the Keystone XL project should be abandoned altogether.

5. The DSEIS Fails to Analyze the Alternative of Refineries Shifting to Domestically Produced Crude Oil

The DSEIS fails to analyze the reasonable and practicable alternative of Gulf Coast Refineries adjusting their refining capabilities to process increased amounts of lighter, cleaner, domestic crude oil rather than heavier crude oil from WCSB.

As discussed throughout the DSEIS and these comments, the main purpose of Keystone XL appears to be supplying heavy crude oil to Gulf Coast refineries, which have already been upgraded to process heavy crude oil. The finished petroleum products will then be shipped largely to overseas markets. The Purpose and Need of Keystone XL, as well as the discussion of alternatives, is focused narrowly on transporting heavy Canadian crude to these refineries.

However, the DSEIS acknowledges that there is an increasing supply of domestically-produced crude oil that these refineries could process if they simply changed their refining capabilities:

> The EIA notes, “AEO2013, AEO2012, and AEO2011 all project continued strong demand for heavy sour crudes from Gulf Coast refiners that are optimized to process such oil” (see the 2013 EIA memo in Appendix C, Market Analysis Supplemental Information). A main driver for this is that although refiners’ can be expected to make adjustments in their operations to take advantage of the increased supply of light crudes on the markets, shutting down their heavy crude upgrading units would likely be the most inefficient and expensive option.[87]

Thus, the DSEIS acknowledges that if Keystone XL and other similar pipeline proposals are denied, Gulf Coast refineries could simply make the switch to producing lighter crude oils produced within the United States. Despite the fact that it might cost refiners more money, that is a reasonable alternative that must be considered as some refineries are already making this

[87] DSEIS, at 1.4-21 and 22.

switch. A Supplemental EIS must quantify what those additional costs might be, and weigh those costs against all of the direct, indirect, and cumulative impacts associated with building and operating Keystone XL.

D. THE DSEIS INCLUDES AN INADEQUATE ANALYSIS OF DIRECT, INDIRECT, AND CUMULATIVE IMPACTS

1. The State Department's Market Analysis and Conclusions Are Flawed and Cannot Be Relied Upon

Perhaps the most significant flaw in the Keystone XL DSEIS is its assertion that tar sands development will increase at the same rate irrespective of whether Keystone XL is approved or not. *See, e.g.*, DSEIS, at 1.4-1 ("Approval or denial of any one crude oil transport project, including the proposed Project, remains unlikely to significantly impact the rate of extraction in the oil sands…"); DSEIS, at 1.4-2 ("Fundamental changes to the world crude oil market, and/or far reaching actions than are evaluated in this Supplemental EIS, would be required to significantly impact the rate of production in the oil sands."); DSEIS, at 1.4-6, 1.4-1 ("Taking account of all of the relevant information, the 2011 Final EIS concluded that the proposed Project is unlikely to significantly affect the rate of extraction in the oil sands or in U.S. refining activities" and "changed circumstances "are not anticipated to alter the outlook for the crude oil market in a manner that would lead to a change in the key conclusions reached in the 2011 Final EIS."

The State Department repeats this faulty assertion throughout the DSEIS, and uses it to downplay the pipeline's clear connection to increased tar sands extraction, increased greenhouse gas emissions, and increased pollution from U.S. refineries. *See., e.g.*, DSEIS, at 1.4-14 ("It is likely that increasing amounts of WCSB crudes will reach Gulf Coast refiners whether or not the proposed Project goes forward."); DSEIS, 4.15-79. In doing so, the State Department conveniently avoids analyzing the Keystone XL's full range of direct, indirect, and cumulative impacts.

As set forth in detail below, the State Department's erroneous claim that the impacts of Keystone XL are inevitable is arbitrary and capricious; is contradicted by a substantial amount of data and industry studies; and violates its obligations under NEPA.

a. The DSEIS Must Analyze the Direct and/or Indirect Effects of Increased Tar Sands Development that Would Occur as a Result of Keystone XL

i. <u>State Department must analyze all effects by which there is a reasonably close causal connection</u>

The DSEIS must include an analysis of "direct effects," which are "caused by the action and occur at the same time and place," as well as "indirect effects which . . . are later in time or farther removed in distance, but are still reasonably foreseeable." 40 C.F.R. § 1508.8. An EIS must also consider the cumulative impacts of the proposed federal agency action together with past, present and reasonably foreseeable future actions, including all federal and non-federal activities. 40 C.F.R. § 1508.7.

The Supreme Court has held that impacts must be analyzed when there is "'a reasonably close causal relationship' between the environmental effect and the alleged cause." *Department of Transportation v. Public Citizen*, 541 U.S. 752, 767 (2004). In *Border Power Plan Working Group v. Department of Energy*, 260 F.Supp.2d 997 (S.D. Calif. 2003) the court found Defendants were required to consider the trans-boundary impacts of certain power turbines in Mexico in their EIS on a U.S. transmission line because the projects were "two links in the same chain." *Border Power Plant Working Group v. Dep't of Energy*, 260 F. Supp. 2d 997, 1016 (S.D. Cal. 2003) ("effects must be causally linked to the proposed federal action in order for NEPA to require consideration of those effects in an EA or EIS.").

Agencies must analyze indirect adverse environmental effect that are "reasonably foreseeable" if it is sufficiently likely to occur. *Mid States Coalition for Progress v. Surface Transp. Bd.*, 2003, 345 F.3d 520.

The *Border Power Plant* decision was based on the premise that the projects were "two links in the same chain." *See also Sylvester v. U.S. Army Corps of Engineers,* 884 F.2d 394, 400 (9th Cir.1989) (agency must consider secondary indirect and cumulative effects of an action other than the proposed action under NEPA if they are "two links of a single chain."); *Port of Astoria, Oregon v. Hodel,* 595 F.2d 467, 480 (9th Cir.1979) (agency's EIS had to consider the supply of federal power and the construction of a private magnesium plant that used the power); *Thomas v. Peterson*, 753 F.2d 754, 761 (9th Cir.1985) (agency's EIS had to consider both a federal road and the federal timber sales that the road would facilitate); *Colorado River Indian Tribes v. Marsh,* 605 F.Supp. 1425, 1433 (C.D.Cal.1985) (agency had to prepare an EIS that considered both the federal action of stabilizing a river bank and the private housing built as a result).

Courts routinely require agencies to consider "growth-inducing" indirect effects of an agency action. *City of Davis v. Coleman*, 521 F.2d 661, 676 (9th Cir. 1975)(requiring analysis of "growth-inducing" impacts of highway interchange); *N. Carolina Alliance for Transp. Reform, Inc. v. U.S. Dept. of Transp.*, 151 F. Supp. 2d 661, 690-91 (M.D.N.C. 2001); *California v. U.S. Dept. of Transp.*, 260 F. Supp. 2d 969, 974 (N.D. Cal. 2003) (EIS for airport failed to analyze impacts on region from hundreds of thousands of additional visitors); *Sierra Club v. Marsh*, 769 F.2d 868, 877–82 (1st Cir.1985) (cargo port and causeway connecting small island to mainland).

Significant evidence demonstrates that Keystone XL would result in increased growth of tar sands development.

ii. <u>The State Department's own analysis demonstrates a causal connection</u>

The State Department's own data demonstrates a causal connection between Keystone XL and increased tar sands development. For example, the State Department relies on several studies conducted by EnSys Energy & Systems, Inc., including the 2010 "Keystone XL Assessment" (EnSys Report) for the U.S. Department of Energy (DOE) Office of Policy and International Affairs.[88] The EnSys Report unequivocally shows that Keystone XL would increase tar sands production as compared to the status quo.

The Report compares various pipeline scenarios and the resulting impacts on tar sands production. The No Expansion scenario assumes that no additional pipelines are built beyond what is currently built or under construction. The EnSys report concludes that under the No Expansion scenario, there would be "significant impacts on the disposition of WCSB crudes" because production would be curtailed by 2024 due to limited export pipeline capacity. EnSys Report, at 93. By contrast, building Keystone XL would allow tar sands production to increase through 2030: "[W]hile Keystone XL…would add to the excess in export capacity through 2020, its capacity- or an alternative (i.e. other projects in Section 3.2)- would be needed soon after 2020 to sustain WCSB production at the levels predicted by CAPP." *Id*. at 31. The EnSys Report found that Keystone XL would allow tar sands production to increase by approximately 800,000 bpd more than it would under the No Expansion alternative between 2020 and 2030.[89]

See Section II.C.1, explaining this causal connection in the context of why the DSEIS's "no action" baseline scenario is flawed.

The State Department has since published several studies explaining why it does not believe the status quo scenario is likely to occur, and the DSEIS makes the same argument once again. However, even if that were accurate, the State Department is simply stating if Keystone XL is not built, some other alternative project may be built *that would have the similar effects on tar sands growth*. The fact that a speculative project might also have a causal connection to increased tar sands development does not negate the causal connection that the State Department's own data demonstrates.

iii. <u>Other evidence demonstrates that Keystone XL would be a key enabler of tar sands growth</u>

Oil industry executives, financial analysts, and environmentalists all agree that Keystone XL is *the* project that is essential to increasing tar sands production. The State Department is completely alone in its conclusion to the contrary.

For example, in an April 10, 2013 hearing before the US House Energy and Commerce Committee, Dr. Mark Jaccard testified. Dr. Jaccard is a professor at Simon Fraser Univeristy, and the former head of the British Columbia Utilities Commission. Dr. Jaccard concluded that

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[88] EnSys Keystone XL Assessment, Final Report (Dec. 23, 2010).

[89] Commenters do not accept this number, and believe that Keystone XL a greater increase in tar sands production that will occur sooner than the EnSys Report suggests. *See infra* Section IV.C.3.d.

KXL will affect tar sands development and in turn will result in increased GHG emissions and other impacts associated with tar sands production.[90] The following are excerpts from Dr. Jaccard's testimony:

> The Draft Supplemental Environmental Impact Statement of the US State Department assumes that denying the Keystone XL pipeline will not appreciably slow development of the Alberta oil sands and the carbon pollution it produces. There is considerable evidence that contradicts this finding. Notably, the lowest cost and highest volume method of transporting oil sands product is via pipelines, yet the other two major proposed pipelines from the oil sands – both of them crossing British Columbia – are unlikely to be approved. Denial of Keystone XL and both of these two pipelines will definitely slow development of the oil sands. This is an important step in addressing increasing carbon pollution in our atmosphere, but it must be combined with many such acts in North America and the rest of the world. Decisions about projects like Keystone XL are of little use unless they are leveraged to greater effect. In this case, the US government should note that it cannot support oil sands expansion while the Canadian government is not making the effort necessary to achieve its 2020 emission reduction target – a target that the US is on course to achieve.
> …
> The Draft Supplemental Environmental Impact Statement of the US State Department assumes that denying the Keystone XL pipeline will not appreciably slow development of the Alberta oil sands and the carbon pollution it produces. There is considerable evidence that contradicts this assumption, and its importance is noted by industry analysts, Canadian politicians and even the oil sands producers themselves.
>
> Quite simply, in the absence of Keystone XL, oil sands producers will find it more difficult to profitably get their product to market. Over the next two decades, the oil sands industry is considering plans to triple its production. To move forward, these projects require a significant expansion of low cost transportation infrastructure. They have potential alternatives to Keystone XL, but these are more costly and more difficult to scale-up to the capacity of Keystone XL, and each faces significant impediments.
>
> Because of their large capacity and low cost, pipelines are preferred. Thus far, the two major pipeline proposals that might compensate for the denial of Keystone XL would ship Alberta bitumen through British Columbia (BC) and then by oil tanker to refineries in Asia and elsewhere. One is the Northern Gateway pipeline proposal of Enbridge, which would be a new pipeline from the oil sands straight west to the north BC coast. The other is the proposal of Kinder Morgan, which would significantly expand the existing Trans Mountain pipeline from Edmonton

[90] Attached as Exhibit 15.

to Vancouver. Both of these would involve a dramatic increase in oil tanker traffic on the BC coast, in the latter case through the port of Vancouver.

[…] Thus far, most opposition to bitumen transport through BC has focused on the Northern Gateway. If the project is cancelled, this opposition would shift its focus to the Trans Mountain expansion proposal.

Industry analysts have noted that these pipelines through BC have less than a 50% chance of being built. If they and Keystone are not built, industry watchers agree that oil sands output will be reduced from what it otherwise would have been.

This is not to say, however, that oil sands producers will stop pursuing new means of getting their product to market. Facing significant discounts for their product, some oil sands producers have turned to rail as a temporary solution. However, rail alternatives are more complicated and costly, and extremely difficult to scale-up to the level of throughput that would fully compensate for the absence of Keystone and either of the BC pipelines. Also, efforts to expand the use of rail for transporting bitumen will create its own counter pressure from concerned citizens along rail right-of-ways and trans-shipment hubs.

More recently, TransCanada is exploring the option of transforming its west-to-east mainline from natural gas to bitumen. This proposal would require the conversion of a half century old natural gas pipeline right-of-way to move oil sands bitumen – a plan that will generate more public scrutiny following the rupture of the repurposed Pegasus pipeline in Arkansas. Moreover, TransCanada's plan would require the construction of a pipeline along new right-of-ways through Quebec and New Brunswick. This would not equate to all of the oil sands development that would have been enabled by Keystone XL and either of the BC pipelines, and it would again trigger a reaction as provincial governments along the way were presented with public concerns similar to those in BC. It must be remembered that opinion polls show that at least 40% of Canadians oppose oil sands expansion. Opposition toward oil sands infrastructure in Quebec, where new pipeline right of ways and construction would be required, is particularly strong.

What should we be asking about Keystone XL?

In the short to medium term, the denial of Keystone XL will help to slow development of the oil sands. As a growing source of carbon emissions, slowing the expansion of oil sands is an important step.[91]

[91] *Id.*

The assertions contained in Dr. Jaccard's testimony are well documented and supported. Prices for WCSB crude oil has dropped in recent years compared to U.S. and international benchmarks because of a lack of export capacity.[92] Enbridge Inc. (ENB)'s Chief Executive Officer Al Monaco said that the current discounts of $30 are unsustainable, and added: "If we can't attract world prices, then we will ultimately curb energy development."[93] Robert Schulz, a business professor at the University of Calgary, stated: "It's fair to say that development has already slowed because of the discount… Companies are certainly going to wait and see what the decision on Keystone is before moving ahead with development."[94] Suncor Energy Inc. CEO Steve Williams stated that it has delayed a joint venture with Total SA and is considering whether to cancel another oil-sands processing plant.[95]

On December 17, 2012, TD Economics (Toronto-Dominion Bank) released a special report entitled, "Pipeline Capacity is a National Priority."[96] It states:

> Canada's oil industry is facing a serious challenge to its long-term growth. Current oil production in Western Canada coupled with the significant gains in US domestic production have led the industry to bump against capacity constraints in existing pipelines and refineries. Production growth can not occur unless some of the planned pipeline projects out of the Western Canadian Sedimentary Basin (WCSB) go ahead. Not doing so would create significant economic loss for the country. TD Economics has previously calculated that the contribution from increased investment in Canada's oil and gas sector accounted for 20% of Canada's economic growth experienced in 2010 and 2011. And, can be a major contributor to growth in the future, but only if new markets are accessed. In a 2012 report, the Canadian Energy Research Institute (CERI) estimated that if the current major pipeline expansion projects which are in the works do not get built, thereby constraining future oil production in Western Canada, Canada would forego as much as $1.3 trillion of GDP (in 2010 Canadian dollars) and $276 billion in taxes from 2011 to 2035.
>
> …
>
> [T]he development of the oil sector is at risk if Canada cannot open up new markets for its growing production through additional pipeline capacity. Western Canadian producers are already suffering price discounts due to their reliance on the U.S. Midwest market, and more diversified market access would help ensure Canadians get the best price for their resources. To achieve this Canada needs to

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[92] Brad Olson and Jeremy van Loon, Keystone Pipeline Decision May Influence Oil-Sands Development, *Businessweek*, March 7, 2013, attached as Exhibit 16.
[93] *Id*.
[94] *Id*.
[95] *Id*.
[96] Attached as Exhibit 17.

> get its crude oil to a port where oil can be shipped by tanker to overseas markets.[97]

Total E&P Canada Ltd. president André Goffart recently stated that building a pipeline to connect oil sands to the U.S. Gulf is the "key issue":

> "This is why Keystone is so important for us – because we have this refinery capable of treating our crude and today we are missing that opportunity because of that logistical constraint," he said. "Over all, we are quite confident that the logistics will adjust. ... Of course, if those main pipeline projects are taking more time, that may impact the timing of the decisions for the biggest projects in the oil sands."[98]

The following quotes from government officials, industry executives, and others further demonstrate that the State Department is alone in its conclusion that Keystone XL is not a lynchpin for tar sands expansion:

> "We've seen a lot of companies based out of Alberta making (spending) decisions that are quite different in the last half of (2012) compared to what they were in the first half of the year…We can no longer continue to rely on oil and gas for 30 per cent of our revenue. It's a fundamental change."
>
> ***Alison Redford***, Alberta Premier – January 25, 2013[99]

> "Oil sands projects display some of the highest break-evens of all global upstream projects. The potential for wide and volatile differentials could result in operators delaying or cancelling unsanctioned projects."
>
> ***Wood Mackenzie***, International Energy Research Firm – June 2012[100]

> "There's a lot of that oil out there in the market. There's plenty of capacity in the Pacific Rim/Asian markets for heavy oil like ours, but it's not infinite and it's certainly competitive." And "If we can get our products into the market in that stream we're going to be competitive…The equivalent of being late is you have to take a bigger and bigger discount on your product, or switch and start supplying a more higher valued-added product."

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[97] *Id*. at 1, 5.
[98] Shawn McCarthy, "Total sets sights on getting oil sands crude to Gulf Coast," *The Globe and Mail*, March 28, 2013, attached as Exhibit 18.
[99] http://www.edmontonjournal.com/business/Lamphier+Bitumen+bubble+burst+leaving+oily+stain+provincial/7874710/story.html
[100] http://www.theglobeandmail.com/report-on-business/crude-glut-price-plunge-put-oil-sands-projects-atrisk/article4230759/

> ***Michal Moore***, Professor of Energy Economics at the University of Calgary – February 7, 2013[101]

"Access to this crucial [Asian Pacific Basin] market will depend critically on the outcome of the pipeline approval process, and also the cost to ship from Canada. If Canada does not approve of the Pacific coast pipeline expansions, or takes too long in doing so, it could find its crude unable to effectively penetrate the world's most promising oil export market."

> ***David Hackett, et al.***, University of Calgary School of Public Policy, "Pacific Basin Heavy Oil Refining Capacity" – February 2013[102]

"If you look at the volume projection going out to 2020, you start saying Northern Gateway's not going to happen, Kinder Morgan's Trans Mountain will be delayed."

> ***Michael Formuziewich***, Portfolio Manager at Leon Frazer & Associates – February 7, 2013[103]

"Pipeline capacity out of Western Canada is adequate for the short term, but substantial progress must be made on this front in 2013. Progress, or lack thereof, will have a big impact on sentiment towards Canadian oil producers. We estimate that pipeline capacity out of the Western Canadian Sedimentary Basin could effectively be full in the 2014 time frame, suggesting little room for error/politicking in bringing on new pipeline capacity."

> ***Andrew Potter***, CIBC oil and gas equity analyst – December 17, 2012[104]

"KXL is likely, therefore, to be moving Canadian bitumen before any of the other major pipeline projects considered in this report. In fact, with KXL in place and operating at capacity, bitumen production could increase substantially and have a major effect on the overall supply/demand situation throughout the North American continent."

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[101] http://www.vancouversun.com/business/Report+says+time+running+Canadian+producers+access+Pacific/7932359/story.html#ixzz2KFbi7YEn

[102] https://docs.google.com/viewer?url=http://policyschool.ucalgary.ca/sites/default/files/research/pacific-basic-refining-capacity.pdf&chrome=true (page 1)

[103] http://www.bloomberg.com/news/2013-02-07/transcanada-looks-east-amid-keystone-pipeline-delay.html

[104] http://www.newswire.ca/en/story/1090187/pipeline-bottlenecks-will-continue-to-discount-price-for-canadian-crude-cibc

***Canadian Energy Research Institute* –** July 2012[105]

"Growing conventional oil, including tight oil, and oil sands production has created an urgent need for additional transportation infrastructure. New pipelines, expansions to existing infrastructure and increased transportation by rail are all required to meet this need for capacity. Pipelines continue to be the dominant mode of transportation for crude oil but it takes time for pipeline infrastructure to be built or expanded."

***Canadian Association of Petroleum Producers* –** June 5, 2012[106]

"Unless we get increased [market] access, like with Keystone XL, we're going to be stuck…We're heading into the same situation with crude oil as we did with natural gas, in that we're going to hit a wall at some point in time and our production is going to be the one backed out of the system, like natural gas has been backed out of the U.S. system. I think it will have a dramatic impact."

Ralph Glass, Vice-president, AJM Petroleum Consultants – June 8, 2011[107]

"If there was something that kept me up at night, it would be the fear that before too long we're going to be landlocked in bitumen. We're not going to be an energy superpower if we can't get the oil out of Alberta."

Ron Liepert, former Alberta Energy Minister – June 8, 2011[108]

b. The DSEIS' Reliance on Speculative Infrastructure Projects to Avoid an Analysis of Increased Tar Sands Development Violates NEPA

i. <u>Keystone XL is the only current proposal that would allow increased tar sands development</u>

Border Power Plant required the agency to analyze the power plant because the line was the only "current means" evidenced by the record through which the turbine could transmit its power, and the turbines and transmission lines were "two links in the same chain." *Id.* at 1017. The same is true with the case of Keystone XL.

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[105] http://www.ceri.ca/images/stories/part_i_-_impacts_of_oil_sands_production_-_final_july_2012.pdf (page 28)
[106] http://www.capp.ca/forecast/Pages/default.aspx (page iii)
[107] http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/without-keystone-xl-oil-sands-face-choke-point/article598717/
[108] http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/without-keystone-xl-oil-sands-face-choke-point/article598717/

The tar sands are being developed in Alberta at a rate of roughly 2 million bpd, and there are existing pipelines that currently transport that crude oil to markets.[109] However, Keystone XL is part of a plan by the Canadian oil industry to expand tar sands production to roughly 6 million bpd by 2030.[110] The tar sands industry cannot grow at that rate without major new export capacity. *See* Section II.D.1.a.iii. Thus, the environmental effects of that tar sands expansion (rather than the existing level of tar sands development) is what the State Department must analyze in its direct/indirect impacts analysis.

Keystone is the "only current means," or only current infrastructure proposal of this magnitude, that would allow that amount of tar sands growth. The SDEIS goes to great lengths to describe all of the alternative infrastructure proposals that may materialize if Keystone XL is rejected. However, those alternatives are speculative at best; each alternative faces similar opposition; each must undergo its own permitting process and environmental review; and none are capable of coming online within the next several years. Therefore, when examining the cause-and-effect relationship between Keystone XL and the ability of the tar sands industry to grow to 6 million bpd, Keystone XL is the only "current" proposal that would allow that to happen.[111]

iii. <u>The DSEIS errs by assuming other infrastructure projects will occur</u>

The DSEIS violates NEPA because it assumes that tar sands development and corresponding GHG emissions will increase at the same rate regardless of whether Keystone XL is built. While it is possible that alternative pipelines or rail projects would be built in the absence of Keystone XL, none are certain or even likely to occur. Therefore, the State Department cannot assume that any will be built so as to avoid analyzing Keystone XL's impacts.

Courts have held that "statements that the indirect and cumulative effects will be minimal or that such effects are inevitable are insufficient under NEPA." *Ctr. for Biological Diversity v. U.S. Dept. of Interior*, 623 F.3d 633, 640 (9th Cir. 2010) (BLM violated NEPA where its EIS assumed the impacts would be the same under every alternative, and therefore failed to provide a

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[109] CAPP 2012 Report.
[110] *Id*.
[111] In *Sierra Club v. Clinton*, 689 F. Supp. 2d 1123, 1134 (D. Minn. 2010), the court wrongly found that there was not "a reasonably close causal relationship" between the impacts of Canadian tar sands development and the construction of the Alberta Clipper tar sands pipeline. The decision was based on the simple premise that "the Canadian tar sands are being developed independently from the AC Pipeline project and that the need for the increased pipeline capacity arises due to the availability of oil from the Canadian tar sands." Id. However, that decision erred because it considered only *existing* levels of tar sands production without acknowledging that the pipeline was being built to accommodate *increased* tar sands production that could not occur but for the pipeline.

comparative analysis of the environmental impacts of the action as compared to the no action alternative); *Davis v. Mineta,* 302 F.3d 1104, 1122–23 (10th Cir.2002); *see also State Farm,* 463 U.S. at 43, 103 S.Ct. 2856.

In other words, an agency may not ignore its duty to examine a project's impacts by "presenting the result as a *fait accompli* incorporated into an environmental baseline. *See Swan View Coalition v. Barbouletos,* No. 6–73–M, 2008 WL 5682094, *16, 2008 U.S. Dist. LEXIS 56677 *45–46 (D.Mont.2008); *League to Save Lake Tahoe v. Tahoe Reg'l Planning Agency*, 739 F. Supp. 2d 1260, 1276 (E.D. Cal. 2010) *aff'd in part, vacated in part, remanded*, 469 F. App'x 621 (9th Cir. 2012).

In *Sierra Club v. United States Dep't of Transp.,* 962 F.Supp. 1037 (N.D.Ill.), the court stated that:

> [T]he final impact statement in this case relies on the implausible assumption that the same level of transportation needs will exist whether or not the tollroad is constructed. In particular, the final impact statement contains a socioeconomic forecast that assumes the construction of a highway such as the tollroad and then applies that forecast to both the build and No–Build alternatives. The result is a forecast of future needs that only the proposed tollroad can satisfy. As a result, the final impact statement creates a self-fulfilling prophecy that makes a reasoned analysis of how different alternatives satisfy future needs impossible.

Id. at 1043.

In *N. Carolina Alliance for Transp. Reform, Inc. v. U.S. Dept. of Transp.*, 151 F. Supp. 2d 661, 690 (M.D.N.C. 2001), the agency avoided an analysis of the impacts of a highway project by reasoning that the project "would simply accommodate already existing growth or growth that was bound to occur whether or not the [highway] was constructed." The court held that "the use of the same statistical data to analyze both the Build and No–Build alternatives fails to provide a reasonable basis for comparison of these alternatives." *N. Carolina Alliance for Transp. Reform, Inc. v. U.S. Dept. of Transp.*, 151 F. Supp. 2d 661, 690 (M.D.N.C. 2001).

The DSEIS improperly assumes that if Keystone XL is not built, some other infrastructure alternative would be built (either pipeline or rail or some combination) that would also have the effect of increasing tar sands development. However, as set forth in Section II.D.1.C, the DSEIS' rail projects are unrealistic and unlikely to occur. Similarly, there is considerable evidence to suggest that alternative pipeline projects are unlikely to occur due to mounting opposition and permitting requirements. In short, alternative transport options are anything but inevitable.

For example, according to the EnSys Report (2010), most proposed crude oil transport projects target Asian markets. Currently, the "WCSB crude export system is highly unusual in that it is currently overwhelmingly land-locked… [and] [w]aterborne exports [to Asian markets] are minor and through only one marine terminal, the Westridge dock near Vancouver." *Id*. at 15. In 2009, exports to Asian markets totaled only 14,000 bbd and depended entirely on Kinder Morgan's Trans Mountain pipeline system that transports WCSB crude from Alberta to Westridge. *Id*. According to a newspaper article, "volumes moving to Asia have reportedly risen to 20,000 bpd." *Id*. Only around 0.56% of exported tar sands crude flows to Asian markets.[112]

As such, while there is considerable interest in establishing a route that would allow higher-volume exports to markets in China, Japan, South Korea, and Taiwan, none of the proposed projects are likely to move forward in the next decade. *Id*. at 17.

In 2008, Kinder Morgan's TMX 1 Project expanded the capacity of the Trans Mountain line to 300,000 bpd. Kinder Morgan has proposed several more expansion projects. The TMX 2 Project would expand Trans Mountain to 380,000 bpd, and TMX 3 would expand it to 700,000 bpd. However, "no decision to go ahead has been taken on either of these projects. This will depend upon level of commercial interest." *Id*. at 17. The EnSys Report describes some of the hurdles these projects face: "Extensive work would be required with various organizations, including the NEB, Port Metro Vancouver and First Nations groups before the project could go ahead. Permits would be required for expansion. In addition, agreements with landowners along the route may have to be renegotiated. These requirements could possibly delay or stop the project…" *Id*. This project would also require dredging the Vancouver harbor and changing regulations to allow increased tanker traffic, both of which have already attracted widespread opposition.[113] Nevertheless, the EnSys Report takes the position that these two Projects "may be the most likely to go ahead of any of the West Coast projects." *Id*. at 18.

Kinder Morgan has also proposed a third expansion project: the Northern Leg expansion of Trans Mountain, which would add a new spur line north to the port of Kitimat that would allow exports to Asia. The proposed capacity of the Northern Leg is 400,000 bpd, which would bring the capacity of the Trans Mountain system to 1.1 mbd (including TMX 2 and TMX 3). *Id*. However, "[t]he Northern Leg expansion is considered by Kinder Morgan to be a longer term project. It also faces strong opposition from First Nations and environmental groups." *Id*. at 18. Furthermore, in December 2010, the Canadian House of Commons passed a motion, supported by four out of five federal parties, calling for the federal government to ban bulk oil tankers off the north coast of British Columbia, which would make it extremely difficult for this project to proceed.[114] In 2010, Kinder Morgan withdrew its intention for these projects due to lack of commercial interest. *Id*.

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[112] *See* Droitsch, Danielle, "*The link between Keystone XL and Canadian oilsands production*," (The Pembina Institute, April 2011), attached as Exhibit 19, at 10 (hereinafter "Pembina Report").
[113] Pembina Report, *supra*, at 11.
[114] Pembina Report, *supra*, at 10.

Perhaps the most controversial West Coast project is Enbridge's proposed Northern Gateway pipeline, which would travel from Edmonton to Kitimat. The capacity would be 525,000 bpd, but would be potentially expandable to 800,000 bpd. *Id*. at 18. Enbridge projects Northern Gateway to be in operation by 2017-2019, if regulatory approvals are obtained and the company decides to build.[115] "However, the project is encountering strong resistance from First Nations and environmental groups, which renders its timing uncertain." *Id*. at 18. Polling shows that 80% of British Columbians oppose the Northern Gateway Project.[116] Moreover, sixty one First Nations that have aboriginal rights and title and who are affected by the proposed pipeline are against both the pipeline and the additional tanker traffic resulting from the project.[117] Given the strong legal rights afforded aboriginals in Canada, especially those on unceded territory, their opposition represents a considerable barrier to the likelihood of the project going forward. For example, the Globe and Mail stated that the First Nations groups "have the constitutional clout to put up insurmountable obstacles for the proposed Northern Gateway – namely, a messy legal debate around unsettled land claims along the route that will likely be decided by the Supreme Court of Canada." [118]

Newer information suggests these proposed west coast pipelines will not be built in the short to medium term. Kinder Morgan's Trans Mountain Expansion has not yet submitted an application to the government. The application, which is expected by the end of 2013, will take 15 months for the government to review and then at least two years to build. An optimistic operational date would be 2017. Enbridge's Northern Gateway is over a year and a half away from a federal government decision. In the unlikely event that the Northern Gateway project is approved, such a decision will likely be contested in courts for many years by concerned British Columbians and legally powerful First Nations groups. The pipeline would take several years to build and would be operational in 2018 at the earliest. Recently, oil industry commentators and federal cabinet ministers who historically have been boosters of west coast pipelines have become less vocal in their support.[119]

A British Columbia (B.C.) provincial election in May 2013 is expected to easily bring the B.C. New Democratic Party (NDP) to a majority government. The B.C. NDP have stated publicly that they are against the Northern Gateway pipeline. In August, the United Church of Canada, the country's largest protestant denomination, "categorically rejected" the Northern

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[115] Montreal Gazette, "Enbridge expects decision on Northern Gateway by end of 2012," 5 April 2011, http://www.montrealgazette.com/news/Enbridge+expects+decision+Northern+Gateway+2012/4558619/story.html
[116] Pembina Report, *supra*, at 10.
[117] Pembina Report, *supra*, at 10.
[118] http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/first-nations-dig-in-against-enbridge-pipeline/article2021928/page1/
[119] Andy Radia, "Northern Gateway may soon need extraordinary political measures to survive," *Yahoo News*, December 3, 2012. http://ca.news.yahoo.com/blogs/canada-politics/northern-gateway-pipeline-may-soon-extraordinary-political-measures-183201589.html

Gateway pipeline.[120] In late October, a rally in British Columbia's capital saw 5,000 concerned Canadians gather in front of the legislature and a few days later there were rallies in 70 communities across British Columbia with more than 7,000 people participating.[121] Within the past few months, many conservative thought leaders in Western Canada are now calling for a 'time-out' on the pipeline that was originally proposed in 2005. [122] Major opposition from nearly every municipality in B.C.'s Lower Mainland creates additional uncertainty for Kinder Morgan's Trans Mountain Expansion. CIBC, a major Canadian financial services firm, now estimates that there is a 50% probability that the west coast proposals by Enbridge and Kinder Morgan will not be built before 2020.[123]

Furthermore, major west-to-east tar sands pipelines are only at the conceptual stage. TransCanada's nascent proposal to retrofit and reverse an underutilized natural gas pipeline to carry 625,000 barrels per day of bitumen to Eastern Canada is years away from application. While Phase 1 of the relatively smaller 240,000 bpd Enbridge Line 9 Reversal project has received federal approval, another segment of this project and a proposed capacity increase to 300,000 bpd still needs government approval. Regardless, the Line 9 Reversal project is significantly smaller than the proposed 830,000 bpd Keystone XL pipeline. This Enbridge project may also connect to a Montreal-to-Portland, Maine, pipeline, for export to the United States. However, this proposal is already seeing growing public opposition in New England.

There are several proposals to transport bitumen to market: two pipeline proposals to Canada's west coast, two more to Canada's east coast, several options for rail, and a few pipeline expansions to the U.S. including Keystone XL.[124] These other proposals individually do not offer the capacity of Keystone XL, are at earlier stages of development and face growing public opposition.

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[120] United Church of Canada, "United Church of Canada Categorically Rejects Northern Gateway Pipeline," press release, August 15, 2012, http://www.united-church.ca/communications/news/releases/120815

[121] Defend Our Coast, "Defend Our Coast," http://defendourcoast.ca/

[122] Deborah Yedlin, "Yedlin: Is it time for a 'time-out' for the Northern Gateway?" *Calgary Herald,* October 12, 2012, http://www.calgaryherald.com/business/time+time+northern+gateway/7379233/story.html; Barbara Yaffe, "Barbara Yaffe: 'Time out' needed in Enbridge pipeline debate," *Vancouver Sun,* October 15, 2012, http://www.canada.com/business/2035/Barbara+Yaffe+Time+needed+Enbridge+pipeline+debate/7393011/story.html; Rod Love, "A bold way out?," *Rod Love Letters: Random observations on politics and life,* August 17, 2012, http://rodlove.com/pipeline-solution-duh/; Tex Enemark, "Dead pipeline walking," *Financial Post,* October 18, 2012, http://opinion.financialpost.com/2012/10/18/dead-pipeline-walking/

[123] Canadian Press, "Oil industry faced with 'serious challenge' as pipelines pill up, TD warns," *Financial Post*, December 17, 2012, http://business.financialpost.com/2012/12/17/oil-industry-faced-with-serious-challenge-as-pipelines-fill-up-td-warns/

[124] For a more detailed summary of these options see: Canadian Association of Petroleum Producers, *2012 CAPP Crude Oil Forecast, Markets & Pipelines Report.*

Proposed Project	Company	Capacity (bpd)	Location	Status
Keystone XL	TransCanada	830,000	Alberta to U.S. Gulf Coast	In application
Northern Gateway	Enbridge	525,000	Alberta to B.C. Coast	In application
TransMountain Expansion	Kinder Morgan	450,000	Alberta to B.C. Coast	Proposed
Line 9 Reversal	Enbridge	300,000	Ontario to Quebec	In application
East Coast Pipeline	TransCanada	625,000	Alberta to Atlantic Canada	Conceptual
Pipeline on Rail	CN Rail, CP Rail	20,000 (2011)	Multiple markets	Pilot stage

Figure 3: Proposed transportation options for oilsands

None of the proposed alternatives to Keystone XL are "likely" to move forward in the long-term, and certainly none will proceed in the short-term. In fact, the DSEIS acknowledges that "other proposed WCSB pipeline projects, including the Enbridge Northern Gateway project to Kitimat, British Columbia, and the Kinder Morgan Trans Mountain pipeline expansions to the Canadian West Coast… are being reviewed, but face significant opposition from various groups, and they may continue to be delayed."[125] The DSEIS notes that the earliest those projects could come online would be 2017.[126]

ii. <u>Other pipelines and rail options would require federal permitting and NEPA review</u>

In fact, alternative pipeline and rail scenarios would undergo their own environmental reviews under federal, state, and local laws. The DSEIS entirely failed to discuss the permitting requirements and other obstacles that these other alternatives face. Instead, it assumes that some alternative will proceed simply because there is sufficient demand for WCSB crude oil in the Texas Gulf Coast.

Courts have held that it is unreasonable for an agency to assume that alternative projects would result in the same impacts if those other projects would have to undergo similar permitting. *Ctr. for Biological Diversity v. U.S. Dept. of Interior*, 623 F.3d 633, 647 (9th Cir. 2010). In *Friends of Yosemite Valley v. Scarlett*, 439 F.Supp.2d 1074, 1037–38 (E.D.Cal.2006), the court found an EIS invalid because every alternative it considered, including the no-action alternative, assumed the existence of projects that required agency authorization but that the agency had not yet validly authorized. *Id.* at 1037–38; *see also League to Save Lake Tahoe v. Tahoe Reg'l Planning Agency*, 739 F. Supp. 2d 1260, 1275-76 (E.D. Cal. 2010) *aff'd in part, vacated in part, remanded*, 469 F. App'x 621 (9th Cir. 2012).

The DSEIS assumes that alternative transport options would be built without acknowledging that many of the alternatives, if not all of them, would require their own permitting requirements and project-specific environmental review. Instead, the DSEIS glosses over this issue by asserting that among the alternatives, "there were many options the midstream

[125] DSEIS, at 1.4-26.
[126] *Id.*

industry possessed to modify existing pipelines and/or make use of existing rights-of-way," implying that none would undergo any permitting review.[127] That assertion is a generalization rather than an absolute truth.

For example, any cross-border infrastructure project or modification must receive a new or amended Presidential Permit pursuant to Executive Order 13337 and undergo its own NEPA review. That includes rail proposals[128] as well as modifications to existing cross-border projects.[129] The DSEIS discusses a possible reversal of an existing pipeline between Montreal, Quebec, and Portland, Maine that would serve to transport tar sands crude oil to export markets in absence of Keystone XL. However, that proposal would require a thorough environmental review under Vermont's "Act 250," which renders it uncertain at best.[130] Any alternative pipelines within the U.S. would be required to apply for federal permits.[131] New rail offloading facilities and other rail infrastructure would similarly be required to obtain permits under various local, state, and federal laws. The DSEIS completely fails to address these permitting requirements.

At the very least, the State Department must discuss what the regulatory barriers to these alternatives would be, and/or disclose that its analysis contains incomplete information. *See N.M. ex rel. Richardson v. Bureau of Land Mgmt.,* 565 F.3d 683, 708 (10th Cir.2009); *Native Ecosystems Council v. U.S. Forest Serv.,* 418 F.3d 953, 964 (9th Cir.2005).

Thus, the DSEIS is arbitrary and capricious because it assumes that alternative infrastructure projects are a foregone conclusion without acknowledging their respective permitting requirements.

c. The DSEIS Analysis of Rail as an Alternative to Keystone XL Is Flawed

The DSEIS's analysis of the logistical obstacles to rail growth for WCSB tar sands is flawed, it's economic analysis for rail as an alternative to Keystone XL for tar sands transport is flawed, and its analysis of tar sands production costs is flawed. These failures lead it to significantly overestimate the viability and economic feasibility of tar sands transport by rail in the event of a rejection of Keystone XL.

i. <u>The DSEIS analysis of rail growth for tar sands crude is flawed</u>

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[127] *Id.* at 1.4-28; see also *id*. at 1.4-32 ("in general, absent larger regulatory changes one can expect infrastructure developments to follow market patterns of supply and demand, which EnSys had described as "business as usual").
[128] 69 Fed. Reg. 25299 (May 5, 2004)
[129] 78 Fed. Reg. 16565 (March 15, 2013)
[130] 10 V.S.A. Chapter 151, attached as Exhibit 20.
[131] DSEIS, at 1.5-1 to 7.

The DSEIS uses flawed data and misinterprets industry sources in its analysis of current trends in moving heavy WCSB crude by rail, that the DSEIS disregards the major differences between transporting heavy tar sands from Northern Alberta and light Bakken crude from North Dakota, fails to distinguish between light and heavy crude when considering rail infrastructure, fails to distinguish heavy tar sands rail shipping agreements and light conventional crude shipping agreements, provides insufficient information on train car purchases to support its conclusions, does not consider the lack of unit train loading facilities for heavy tar sands crude, incorrectly analogizes between coal and WCSB crude by rail, ignores congestion associate with rail as an alternative to Keystone XL.

A. The DSEIS misinterprets current trends in WCSB crude by rail

The DSEIS misinterpreted industry sources to suggest that 120,000 bpd of heavy crude is already moving to Gulf Coast refineries by rail and 200,000 bpd of Canadian heavy crude will reach Gulf Coast refineries by rail by the end of 2013.[132] According to a recent Reuters report:

> "The State Department report cites two industry studies to predict that 200,000 barrels a day or more of Canadian heavy crude oil will reach Gulf Coast refiners by train by the end of this year.
>
> Officials used that figure to bolster their argument that the oil industry has already decided rail is a good option for moving oil sands crude. "Limitations on pipeline transport would force more crude oil to be transported via other modes of transportation, such as rail, which would probably (but not certainly) be more expensive," the State Department said.
>
> But one of the sources for the 200,000 barrels per day estimate, Calgary investment bank Peters & Co, says its forecast was misunderstood as being for just Gulf Coast-bound oil when it included shipments to Eastern Canada and other refiners.
>
> "We haven't tracked exactly where those barrels are going," said Tyler Reardon, a spokesman for Peters & Co.
>
> The other source for the number, Hart Energy, did predict in a report last year that 250,000 barrels per day of heavy crude from Western Canada would be reaching the Gulf Coast before the end of this year but its analysts are reviewing that forecast.
> "Hart Energy continues to carefully monitor flows from Western Canada," said Susan Emfinger, a spokeswoman for the Houston energy consultant.
>
> The latest figures from the U.S. Energy Information Administration show heavy crude shipments to the Gulf Coast from Canada by rail have a long way to go to meet the

[132] *Id*. at 1.4-38.

> 200,000 figure. They have not exceeded 30,000 barrels per day in any of the past 12 months, though they did rise by two thirds to 25,000 barrels per day in January, the last month for which there are figures, from 15,000 in January 2012.
>
> In fact, EIA data shows that little heavy crude from Canada is reaching the Gulf Coast via any route, with about 75 percent of 33 million barrels of heavy Canadian crude being processed in the Midwest in January and only 7 percent of it being processed further south. Other destinations account for the remainder.
>
> "We just are not seeing those kinds of big deliveries to the Gulf Coast," said Michael Wojciechowski, head of downstream Americas research at Wood Mackenzie, an energy research and consulting firm."[133]

The Reuters investigation of Energy Information Administration export data shows that heavy crude shipments from Canada to the Gulf Coast by have averaged 20,267 bpd over the last six months (from July 2012 to January 2013).[134] Moreover, the increase from January 2012 to January 2013 had only been approximately 10,000 bpd.[135] This was after a year of sustained, significant discounts for Canadian heavy crude relative to international benchmarks.[136] In December 2012, the discount for Canadian tar sands exceeded $40 a barrel relative to West Texas Intermediate, which itself was discounted to international heavy crude blends trading on parity with tar sands at the Gulf.[137]

This data shows that rail continues to be a marginal transportation option for WCSB heavy crude. Despite sustained deep discounts, only about 1% of WCSB tar sands crude production is shipped to the Gulf by rail.[138]

B. The DSEIS disregards the economic differences between transporting heavy tar sands from Northern Alberta and light Bakken crude from North Dakota

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[133] Patrick Ruckers, Analysis: Oil-by-train may not be substitute for Keystone pipeline, Reuters, http://www.reuters.com/article/2013/04/18/us-usa-keystone-railroads-idUSBRE93H07I20130418.
[134] Reuters, Long Train Running, April 18, 2013, http://pdf.reuters.com/pdfnews/pdfnews.asp?i=43059c3bf0e37541&u=2013_04_16_07_22_eabbec37e1e24f77a1b3498deecbbeb6_PRIMARY.gif.
[135] Patrick Ruckers, Analysis: Oil-by-train may not be substitute for Keystone pipeline, Reuters, http://www.reuters.com/article/2013/04/18/us-usa-keystone-railroads-idUSBRE93H07I20130418.
[136] Anthony Swift, On the wrong track: Rail is not an alternative to the Keystone XL tar sands pipeline, March 6, 2013, http://switchboard.nrdc.org/blogs/aswift/on_the_wrong_track_rail_is_not.html.
[137] Alberta Government, Alberta's Heavy Oil Prices, January 11, 2013, www.energy.alberta.ca/Org/pdfs/FSheavyOilPrices.pdf; Bloomberg, Canadian Energy Companies Weighing Cuts on Oil Discounts, Jan. 16, 2013, http://www.bloomberg.com/news/2013-01-16/canadian-energy-companies-weighing-cuts-on-oil-discount.html.
[138] Canadian Association of Petroleum Producers, Crude Oil: Forecasts, Market & Pipelines, June 2012, www.capp.ca/getdoc.aspx?DocId=209546&DT=NTV.

A cornerstone of the DSEIS's conclusion that rail is a feasible alternative to Keystone XL is the example of rail use by oil producers in North Dakota and Montana.[139] However, although over the last three years producers of light crude in the Bakken oilfields have responded to price discounts and transportation constraints by turning to rail to move their crude to market, this same scenario does not apply in the Canadian tar sands.

From 2009 to 2013, transport of oil by rail in North Dakota increased from a few thousand barrels a day to over half a million.[140] From January 2012 to January 2013, crude by rail transport of Bakken crude from North Dakota increased from 145,000 bpd to 564,000 bpd, or from 27% to 76% of production. [141]

As they turned to rail, domestic light oil producers have even rejected major pipeline proposals – including Oenok's 200,000 barrel per day Bakken pipeline.[142] When analysts talk about the upsurge of rail transport in the United States and southern Canada, this is what they're referring to – an enormous expansion of light crude from the Bakken.

However, a similar expansion has not occurred in Alberta's tar sands despite the need for additional transportation infrastructure. Despite sustained deep discounts, only about 1% of WCSB tar sands crude production is shipped to the Gulf by rail.[143]

There are two major reasons why tar sands producers haven't turned to rail to move their product to market. First, it is significantly more expensive for them to do so, and second, they have significantly tighter profit margins than Bakken producers.

Tar sands diluted bitumen is significantly more expensive to move by rail than Bakken light crude. There are a number of reasons for this:

- The tar sands are about 900 miles farther away from refinery markets than the Bakken oil fields.[144]

[139] DSEIS, at 1.14-45-46.
[140] North Dakota Pipeline Authority, U.S. Williston Basin Rail Export Estimates, April 1, 2013, http://ndpipelines.files.wordpress.com/2012/04/ndpa-website-data13.xlsx.
[141] In January 2012, 2012 North Dakota produced 535,000 bpd, of which 145,000 bpd was transported by rail; while in January 2013, North Dakota production increased to 738,000 bpd, of which 564,000 bpd move on rail. U.S. Energy Information Administration, North Dakota Field Production, http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPND2&f=M. North Dakota Pipeline Authority, U.S. Williston Basin Rail Export Estimates, April 1, 2013, http://ndpipelines.files.wordpress.com/2012/04/ndpa-website-data13.xlsx.
[142] Chicago Tribune, Oenoek Update 1: Cancels 200,000 bpd Bakken Project, Nov. 1, 2012, http://articles.chicagotribune.com/2012-11-27/news/sns-rt-oneok-bakkenpipeline-update-1l1e8mrbzd-20121127_1_overland-pass-pipeline-bakken-crude-express-pipeline-oneok-partners-lp.
[143] Canadian Association of Petroleum Producers, Crude Oil: Forecasts, Market & Pipelines, June 2012, www.capp.ca/getdoc.aspx?DocId=209546&DT=NTV.

- Trains moving light crude can carry nearly 30% more crude than trains moving heavy tar sands diluted bitumen.[145]
- Moving tar sands requires specialized rail offloading terminals, onloading terminals and heated rail cars.[146]

All of these factors increase the cost of moving a barrel of tar sands to Gulf Coast refineries. Shipping a barrel of tar sands diluted bitumen to the Gulf is currently costing tar sands producers $31 a barrel.[147] Moving it by pipeline only costs $8 to $9.50 a barrel.[148]

Tar sands producers also have much tighter margins than conventional Bakken producers. Tar sands crude is a lower value commodity than Bakken light crude. In addition, it has significantly higher production prices. With breakeven production costs ranging from $60 a barrel to over $100 a barrel – and increasing by each year – new tar sands projects cannot profitably bear significantly greater transportation costs associated with rail.[149]

C. The DSEIS fails to distinguish between light and heavy crude when considering rail infrastructure developments

The DSEIS fails to distinguish between rail infrastructure built to receive increasing light crude oil production from the Bakken and heavy crude oil from the WCSB. When considering the development of rail offloading infrastructure, the DSEIS does not distinguish between infrastructure oriented to receive light crude from the Bakken in North Dakota and southern Canada and heavy crudes from Alberta.[150] There are many differences between light and heavy production including location, infrastructure requirements, transportation costs, markets, production prices, product prices and environmental impacts. Moreover, while there has been a recent surge of light crude production, the vast majority of WCSB crude production increases

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144 Patrick Ruckers, Analysis: Oil-by-train may not be substitute for Keystone pipeline, Reuters, http://www.reuters.com/article/2013/04/18/us-usa-keystone-railroads-idUSBRE93H07I20130418.

145 Light crude train cars can move up to 700 barrels while heavy train cars can only move 550 barrels. Doug Wilkins, Integrated Midstream Solutions, TD Securities 'Crude By Rail Forum, pg. 11, October 2, 2012.

146 Doug Wilkins, Integrated Midstream Solutions, TD Securities 'Crude By Rail Forum, pg. 11, October 2, 2012.

147 Nicole Mordant, Analysis: Crude-by-rail carves out long-term North American niche, Reuters, Nov. 4, 2012, http://www.reuters.com/article/2012/11/04/us-railways-oil-northamerica-idUSBRE8A30AX20121104.

148 DSEIS, at 1.4-49.

149 Energy Conservation Resources Board, ST98-2012 Alberta's Energy Reserves 2011 and Supply/Demand Outlook 2012–2021, pg. 3-30, June 2012; Pembina Institute: January 28, 2013 "Beneath the Surface" Report (Pg. 57) http://www.pembina.org/pub/2404; Katusa, Marin. "Oil Price Differentials: Caught Between the Sands and the Pipelines." *Forbes* 6 June 2012. Web. http://www.forbes.com/sites/energysource/2012/06/21/oil-price-differentials-caught-between-the-sands-and-the-pipelines/3/

150 DSEIS, at 1.4-34.

will be of heavier crudes – both tar sands and conventional heavy.[151] Given the differences between market factors affecting light and heavy production, distinguishing between infrastructure designed and intended to receive primarily light crude oil by rail and that intended to move heavy crude by rail is critical to evaluate the viability of rail as an economic alternative to move heavy WCSB crudes.

D. The DSEIS fails to distinguish between publicly announced shipments of conventional light crude and heavy tar sands crude by rail

The DSEIS provides publicly announced crude by rail project without distinguishing between light conventional production and heavy tar sands production.[152] These projects include both light and tar sands production. For reasons discussed above, distinguishing between facilities intended and/or designed to receive light and heavy crude is critical to evaluate the feasibility and production rationing impact of rail as an alternative to Keystone XL.

E. The DSEIS does not provide sufficient information supporting train car purchases

The DSEIS bases much of its analysis on a press report by Torq Transloading that “at least 60 percent of the tank cars now being manufactured are of the insulated type.”[153] The State Department does not provide the document to support this statement. The data Torq Transloading relied on for this information is not clear, nor is it clear that the press report by Torq Transloading supports the DSEIS assertion that this figure applies to the three year backlog of traincars.

F. The DSEIS does not consider the lack of unit train loading facilities for heavy tar sands crude

The DSEIS notes the critical role that unit train facilities have played in the expansion of rail in the Bakken region of North Dakota and Southern Canada but fails to discuss the lack of unit train infrastructure designed for tar sands.[154] Industry sources indicate that there are not any unit trains currently running from Western Canada to the Gulf Coast.[155]

According to Figure 1.4.6-5, there are 15+ Canadian Loading Facilities, with a 2013 capacity of 240,000 bpd, indicating that these facilities have an average capacity of less than

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[151] Canadian Association of Petroleum Producers, Crude Oil: Forecasts, Market & Pipelines, pg. 38, June 2012, www.capp.ca/getdoc.aspx?DocId=209546&DT=NTV.
[152] DSEIS, at 1-4.43.
[153] *Id.* at 1-47.
[154] DSEIS, at 1-4.51.
[155] Patrick Ruckers, Analysis: Oil-by-train may not be substitute for Keystone pipeline, Reuters, http://www.reuters.com/article/2013/04/18/us-usa-keystone-railroads-idUSBRE93H07I20130418.

16,000 bpd. Meanwhile, also according to Figure 1.4.6-5, there are fifteen Bakken Loading Facilities, with a 2013 capacity of 1,215,00 bpd, indicating that these facilities have an average capacity of 81,000 bpd; average capacity could increase to almost 100,000 bpd as these facilities continue to expand. Put simply, loading facilities in the Bakken are of a size consistent with unit trains, but the facilities in Canada are not.

G. The DSEIS incorrectly analogizes between coal and WCSB crude by rail

The DSEIS made an oversimplified comparison between coal and oil by rail to evaluate the feasibility of rail as an alternative to WCSB.[156] Coal by rail and heavy oil by rail are not apple to apple comparisons. Heavy crude refinery markets with excess capacity are fairly concentrated on the Gulf Coast, while coal buyers in the United State are far more evenly distributed throughout the country. The DSEIS should consider the viability of a significantly more concentrated delivery of heavy crude by rail to the Gulf Coast.

H. The DSEIS ignores congestion associated with rail as an alternative to Keystone XL

The DSEIS fails to consider congestion associated with significant volumes of WCSB crude by rail. The DSEIS notes that a single unit train shipment of crude will require twenty unit trains sets (due to the long round trip).[157] A hundred car unit train carrying heavy crude will transport about 55,000 bpd.[158] Moving 830,000 bpd will require the addition of over 300 hundred car unit trains constantly moving between Hardesty and the Gulf Coast. The DSEIS must consider the impact of congestion on the feasibly of rail transport as a reasonable alternative to Keystone XL.

I. The DSEIS fails to consider capital investment shifts to increase Gulf Coast light crude refining capacity

The DSEIS does not consider capital investments currently being made to reconfigure Gulf Coast refineries to increase their capacity to process light crude at the expense of their heavy crude refining capacity. In addition, the DSEIS does not consider its assumption of increasing investment in heavy refining capacity in context of increasing North American production of light crude oil.[159]

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[156] DSEIS, at 1.4-46.
[157] *Id.* at 1.4-47.
[158] Light crude train cars can move up to 700 barrels while heavy train cars can only move 550 barrels – a 100 car train moving heavy crude will transport about 55,000 bpd. Doug Wilkins, Integrated Midstream Solutions, TD Securities ‘Crude By Rail Forum, pg. 11, October 2, 2012.
[159] Ian Goodman, Report evaluating the adequacy of the Keystone XL (KXL) Draft Supplemental Environmental Impact Statement (DSEIS) Market Analysis, April 22, 2013, Section 4.5.

J. The DSEIS fails to consider foreign ownership by non-Canadian heavy crude producers

The DSEIS fails to consider foreign ownership by non-Canadian heavy crude producers.[160] Some Gulf Coast heavy crude refineries are less likely to process tar sands crudes because of their ownership by non-Canadian heavy crude producers – including state-controlled companies from Mexico and Venezuela.[161] As a result, these refineries are less likely to shift to processing tar sands crudes.[162] The DSEIS does not consider this factor when it evaluates the size of the heavy crude oil market for Canadian tar sands crude in the Gulf Coast.

ii. <u>The DSEIS cost estimates for heavy tar sands transport by rail is flawed</u>

A. The DSEIS incorrectly compares uncommitted rail costs to uncommitted pipeline costs, rather than the likely costs of the Keystone XL pipeline

The DSEIS suggests that rail tariffs should be compared to the higher uncommitted pipeline tariffs rather than committed pipeline tariffs.[163] It's rationale for this comparison is because rail rates tend to be based on shorter contracts – which increase the cost of rail.[164] However, the majority of the capacity on Keystone XL is confirmed based on long term contracts. Differences between contracting structures is an important difference between the cost structure of rail and the project. The State Department must consider the cost of rail and the Keystone XL pipeline based on the contracting structures they are most likely to employ rather than ones that put them at greatest parity.

B. The DSEIS doesn't evaluate the higher cost of moving heavy WCSB crudes

The DSEIS doesn't differentiate between the cost structures of moving light and heavy crude by rail. The DSEIS projects that the cost of moving WCSB crudes will be approximately $15.50 per barrel.[165] It is unlikely that heavy crude and light crude could be moved at the same rate per barrel – and yet the DSEIS's estimates don't distinguish between these products. Heavy crude requires specialized rail cars and offloading facilities. Moreover, train car weight restrictions reduce the amount of heavy crude which can loaded onto a train car – heavy train

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[160] *Id.*, Section 4.6.
[161] *Id.*
[162] *Id.*
[163] DSEIS, at 1.4-49.
[164] *Id.* at 1.4-50.
[165] *Id.* at 1.4-49.

cars can only carry 550 barrels while cars can move as much as 700 barrels.[166] These differences in infrastructure and capacity likely have a significant impact on the economics of moving heavy and light crude. This distinction is not evaluated in the DSEIS, nor does the DSEIS provide analysis with enough specificity and/or supporting materials to evaluate its treatment of this issue.

> As a recent Reuters investigation observed:
>
> "The logistical challenges to moving heavy crude by rail can be overcome, industry officials and analysts say, but the economics are not so clear-cut.
>
> While the State Department says in the report that moving a barrel of heavy crude through a Keystone pipeline would cost no more than $10 a barrel, oil sand producers say they are facing costs closer to $30 a barrel by train.
>
> Those economics are tenuous, said Sandy Fielden, director of energy analytics with RBN Energy LLC in Houston, who has studied crude-by-rail. "If rail were such a terrific option now out of Western Canada, why haven't more producers switched from pipeline to rail?"
>
> Gulf Coast refiners are specialists at turning heavy, sulfurous crude from Mexico and Venezuela that arrives by tanker into clean-burning gasoline for cars, so they are already equipped to process Canadian oil sands.
>
> The problem, analysts say, is that the Canadian crude will have to be priced to compete against those shipments, as well as crude arriving at the Gulf refineries from Saudi Arabia.
>
> Mayan crude, the Mexico benchmark akin to oil sands crude, was trading at about $106 a barrel in March, while the Canadian product was valued at about $83 in markets north of the border. Oil sand producers therefore had incentives to move a barrel of their product to the Gulf Coast if they could do so under the roughly $23 spread, said Fielden.
>
> Midwest refiners and existing pipelines are able to absorb oil sands production for now, the Canadian Association of Petroleum Producers has said, but producers will face a critical shortage of pipelines by the end of next year.

[166] Light crude train cars can move up to 700 barrels while heavy train cars can only move 550 barrels. Doug Wilkins, Integrated Midstream Solutions, TD Securities 'Crude By Rail Forum, pg. 11, October 2, 2012.

> "The cheapest way to get from point A to point B is a pipeline," said Raymond James analyst Steve Hansen. "That is why Keystone has got to go ahead."[167]

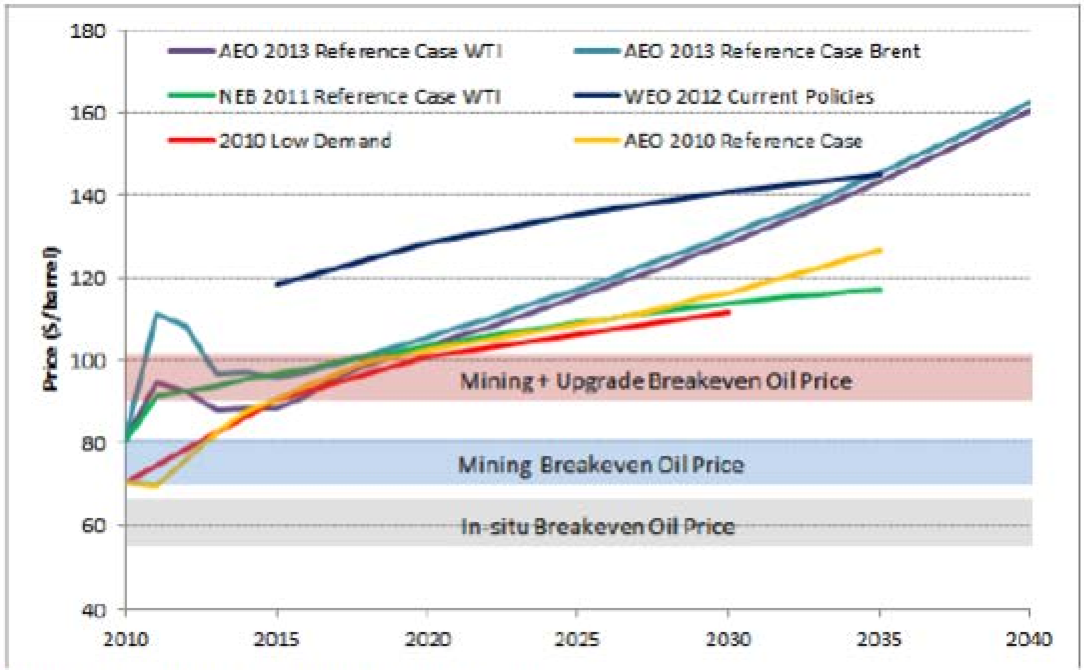
Southern Pacific is currently paying $31 a barrel to move diluted bitumen from Alberta to the Gulf Coast.[168] The DSEIS does not analyze this arrangement or account for it cost above its estimates.

The DSEIS should consider the higher cost of moving heavy crude bitumen from Northern Alberta to the Gulf Coast with specificity.

iii. The DSEIS's analysis of tar sands production costs is flawed

The DSEIS conclusion that rail is an economically feasible option is also based on a fundamental flaw in its analysis of the long term profitability of tar sands production. While the DSEIS acknowledged that many new tar sands projects are economically challenged, it assumed that oil prices would increase through 2035 and concluded that if production costs stay constant, new tar sands projects would be able to bear slightly higher transport costs.[169] The State Department expresses this argument in the graph below in which it adds its low estimate of the cost difference between rail and pipeline to NEB's 2011 breakeven price and assumes that these new production costs will stay constant through 2040.

[167] Patrick Ruckers, Analysis: Oil-by-train may not be substitute for Keystone pipeline, Reuters, http://www.reuters.com/article/2013/04/18/us-usa-keystone-railroads-idUSBRE93H07I20130418.
[168] Reuters, Southern Pacific Resource Corp. completes arrangements to transport and market bitumen via CN to the U.S. Gulf Coast, June 27, 2012, http://www.reuters.com/article/2012/06/27/idUS208002+27-Jun-2012+PRN20120627.
[169] DSEIS, at 1.4-53.



Source: EIA 2013, EIA 2010, EnSys 2010, NEB 2011, IEA 2012c.

Figure 4. Source: State Department draft SEIS for Keystone XL, 1.4-53.

However, the DSEIS assumption that production costs will remain constant is fundamentally flawed – particularly in scenarios involving rising energy costs and tar sands expansion. Tar sands production is dependent on the cost of labor, material and energy, and these costs have been rapidly increasing and are likely to continue to do so if industry pursues its plan to triple production by 2030. In fact, it appears that the 2011 breakeven prices that are State used are already significantly lower than those faced by tar sands producers today.

Fig. 5. Increasing Costs of Tar Sands Production			
	NEB 2011 (Baseline for State's 2013 draft SEIS)[170]	Alberta 2011 (ERCB)[171]	Alberta 2012 (ERCB)[172]
New In Situ	$51 - $61	$47 - $57	$50 - $78
New Mining (no upgrading)	$66 - $76	$63 - $81	$70 - $91
New Mining w/ upgrading	$86 - $96	$88 - $102	NA

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[170] *Id.*
[171] Energy Conservation Resources Board, ST98-2011: Alberta's Energy Reserves 2010 and Supply/Demand Outlook 2011-2020, June 2011, pg. 3-24, http://www.ercb.ca/sts/ST98/st98-2011.pdf.
[172] Energy Conservation Resources Board, ST98-2012, Alberta's Energy Reserves 2011 and Supply/Demand Outlook 2012–2021, June 2012, 3-30, http://www.ercb.ca/sts/ST98/ST98-2012.pdf.

Tar sands production prices have been rapidly increasing and are likely to continue to do so. The upper bound of tar sands breakeven prices appear to have increased by about $15 a barrel across all types of projects from 2011 to 2012.

Northern Alberta tends to have high labor and material costs due to its constrained labor pool and inland location. In discussing the economics of constructing upgrading and refining projects, IHS CERA identified some of the issues associated with cost escalation in Alberta:

> "Cost is a barrier for new upgrading or refining projects in Alberta; when projects were first proposed (in the earlier 2000s), investors expected lower price tags. From 2000 to 2008 (as measured by the IHS CERA Capital Costs Index) costs for building upgraders or refineries in Alberta increased by 70%.* The rate of change was borne out on actual projects built this decade, which had final price tags that were 50% to 100% higher than original estimates. Although costs softened during the recession, they have since recovered and are now higher than pre-recession levels. The situation is not unique to Alberta. Project costs around the globe registered similar escalation owing to increased demand for commodities, equipment, and specialized personnel. However, with absolute costs in Alberta already higher than most other regions, escalation had a more severe impact on project economics in Alberta.*"[173]

And:

> **"Construction techniques.** Owing to differing construction methods, inland locations are more expensive to build. With ocean access, larger components or modules of the facility can be built off site. Once complete, the modules can be transported to site and assembled like building blocks. This technique materially reduces the labor requirements and—consequently—the cost. Access to the ocean is critical, because modules can be the size of a football field and need to be transported by ship. Although inland locations can use this method, since the modules must be transported by truck, this materially reduces the module size and corresponding cost savings.
>
> **Labor costs.** Construction labor is a large factor in why costs vary among regions. In North America direct labor typically makes up 30% of a project's total cost, and labor costs in Alberta are higher than those of other regions. One cause is the limited regional pool of construction workers (demand from oil sands projects often exceeds local supply, requiring workers to be recruited from across Canada and the globe). Another is Alberta's landlocked location, keeping on-site labor requirements relatively high (see construction techniques). Climate is also a concern; cold weather decreases worker productivity."[174]

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[173] IHS CERA, Extracting Economic Value from the Canadian Oil Sands Upgrading and refining in Alberta (or not)? Special Report, 2013, pg. 4.
[174] *Id.* at pg. 9-10.

By underestimating tar sands production costs, the DSEIS underestimated the impact that higher transportation costs will have on the profitability of new tar sands projects and overall production rates.

iv. Independent Market Analysis demonstrates fundamental flaws in the DSEIS

Market analysis by The Goodman Group reveals fundamental flaws in the DSEIS. The detailed critique presented by TGG is incorporated in comments in Appendix I. TGG concludes that the DSEIS "is deeply flawed and not a sound basis for decision-making."[175] Based on its analysis, TGG concludes "that KXL, and specifically its impact on tar sands logistics costs and crude prices, will have a significant impact on tar sands expansion under a very broad range of conditions and assumptions."[176] TGG states that a conservative and credible estimate of Keystone XL's impact on tar sands expansion would be 830,000 bpd based on its expert evaluation of current market conditions.[177]

v. The DSEIS does not provide the supporting materials to permit adequate public comment on its market analysis.

The State Department has not made critical supporting documents available pursuant to a FOIA. Many of these documents form a critical basis for the DSEIS conclusions in its Market Analysis. In addition, many of the assertions in the DSEIS's forecast of the cost of transporting heavy crude by rail do not clearly cite or explain how they were derived with specificity. This is particularly concerning given press reports indicated that original sources cited by the DSEIS indicate the State Department misinterpreted their data it to reach conclusions that were not supported by that data.[178] Without full access to the information used in the DSEIS to reach its conclusions, it is not possible to provide adequate comment on those conclusions. The State Department should re-release the DSEIS with all of the supporting materials used in its analysis and give the public adequate time to provide meaningful comments.

2. The DSEIS Fails to Adequately Analyze Climate Impacts

a. Climate Science Overview

Climate change from the anthropogenic emissions of climate pollutants poses a number of significant threats to Earth's inhabitants, which include: losses to the cryosphere; rapid sea level rise; more extreme weather events; imperiled biodiversity; harms to the oceans; injury to

[175] Ian Goodman, Report evaluating the adequacy of the Keystone XL (KXL) Draft Supplemental Environmental Impact Statement (DSEIS) Market Analysis, April 22, 2013, Section 7.0.
[176] *Id.*
[177] *Id.*
[178] Patrick Ruckers, Analysis: Oil-by-train may not be substitute for Keystone pipeline, Reuters, http://www.reuters.com/article/2013/04/18/us-usa-keystone-railroads-idUSBRE93H07I20130418.

human health and reduced food security. Current atmospheric concentrations of greenhouse gases are already resulting in severe and significant climate change impacts that are projected to worsen as emissions rise.[179] The US EPA has found that climate change endangers the health and welfare of this and future generations.[180] We are fast approaching a global "state-shift" that could result in unanticipated and rapid changes to Earth's biological systems.[181]

The most direct impact of accumulated climate pollutants is global warming – an increase in global atmospheric temperatures. The atmospheric concentration of CO_2 reached ~392 parts per million (ppm) in 2011[182] compared to the pre-industrial concentration of ~280 ppm. The current CO_2 concentration has not been exceeded during the past 800,000 years and likely not during the past 15 to 20 million years.[183] The growth rate of carbon dioxide emissions has largely tracked or exceeded the most fossil-fuel intensive emissions scenario projected by the IPCC (A1FI).[184] The result is that the decade from 2000 to 2010 was the warmest on record,[185] and 2005 and 2010 tied for the hottest years on record.[186] By the end of this century, the average temperature in the United States is expected to increase by 2.2 to 3.6°C (4 to 6.5°F) under a lower emissions scenario and by 3.9 to 6.1°C (7 to 11°F) under a higher emissions scenario.[187]

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[179] U.S. Global Change Research Program, Global Climate Change Impacts in the United States (2009).
[180] U.S. Environmental Protection Agency, Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act; Final Rule, 74 Federal Register 66496 (2009).
[181] A.D. Barnosky et al., *Approaching a state shift in Earth's biosphere*, 486 NATURE 52 (2012), attached as Exhibit 21.
[182] *See* National Oceanic and Atmospheric Administration, *Trends in Atmospheric Carbon Dioxide*, www.esrl.noaa.gov/gmd/ccgg/trends/global.html.
[183] Kenneth L. Denman et al., *Couplings Between Changes in the Climate System and Biogeochemistry, in* Climate Change 2007: The Physical Science Basis - Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change 500 (Susan Solomon et al., eds. 2007), attached as Exhibit 22; Aradhna K. Tripati et al., *Coupling of CO2 and ice sheet stability over major climate transitions of the last 20 million years*, 326 SCIENCE 1394 (2009), attached as Exhibit 23.
[184] Michael R. Raupach et al., *Global and Regional Drivers of Accelerating CO_2 Emissions*, 104 PROC. OF THE NATL. ACAD. OF SCIENCES OF THE U.S. 10288 (2007), attached as Exhibit 24; C. McMullen & J. Jabbour, UNEP, CLIMATE CHANGE SCIENCE COMPENDIUM 2009 (2009), attached as Exhibit 25; Katherine Richardson et al., SYNTHESIS REPORT FROM CLIMATE CHANGE: GLOBAL RISKS, CHALLENGES AND DECISIONS (Copenhagen March 10-12, 2009), *available at* climatecongresss.ku.dk, attached as Exhibit 26; Global Carbon Project, Carbon Budget 2009 (2010); Global Carbon Project, Carbon Budget 2010 (2011).
[185] Press Release, National Aeronautic Space Association, *NASA Research Finds Last Decade was Warmest on Record, 2009 One of the Warmest Years* (Jan. 21, 2010), www.nasa.gov/home/hqnews/2010/jan/HQ_10-017_Warmest_temps.html.
[186] National Oceanic and Atmospheric Administration, *NOAA: 2010 Tied for Warmest Year on Record,* www.noaanews.noaa.gov/stories2011/20110112_globalstats.html.
[187] U.S. Global Change Research Program, Global Climate Change Impacts in the United States (2009).

Such extensive global warming is decimating the cyrosphere. Arctic summer sea ice extent and thickness have decreased to about half of what they were several decades ago,[188] with an accompanying drastic reduction in volume,[189] which is severely jeopardizing ice-dependent animals.[190] In fact, the Arctic is now predicted to be ice free in the summer as early as 2020 based on extrapolation of trends in sea ice extent.[191] Ice sheets in Greenland and the Antarctic are also vulnerable to significant melting in a warmer world. Greenland has been experiencing accelerated ice loss, with recent studies finding that minimal temperature increases could result in complete loss[192] and that northern portions of Greenland's ice sheet may be more vulnerable than previously believed.[193] Like ice, the consensus is that, as a whole, the Earth's glaciers are exhibiting rapid recession.[194] For example, the number of glaciers at Glacier National Park has dropped from 150 to 26 since 1850, with some projections suggesting that if current trends in the rate of melting continue, the remaining glaciers will be gone in the next 25 to 30 years.[195] Glaciers and seasonal snowpack are important freshwater reservoirs; early and increased rates of melting jeopardize water availability in many regions.[196]

These losses to the cryosphere have already resulted in a rise in sea level, and are projected to result in further, substantial increases in sea level. Global average sea level rose by roughly eight inches (20 centimeters) over the past century, and sea level rise is accelerating in pace.[197] Recent studies documenting the accelerating ice discharge from ice sheets indicate that

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[188] J. Stroeve et al., *Arctic Sea Ice Extent Plummets in 2007*, 89 EOS 2 (January 8, 2008), attached as Exhibit 27; R. Kwok and D.A. Rothrock, *Decline in Arctic sea ice thickness from submarine and ICESat records: 1958-2008*, 36 GEOPHYS. RES. LETT. L15501 (2009), attached as Exhibit 28.

[189] Polar Science Center, *Arctic Sea Ice Volume Anomaly, version 2*, http://psc.apl.washington.edu/wordpress/research/projects/arctic-sea-ice-volume-anomaly/.

[190] Center for Biological Diversity and Care for the Wild International, EXTINCTION: IT'S NOT JUST FOR POLAR BEARS (2010), attached as Exhibit 29.

[191] J.E. Overland and M. Wang, *When will the summer Arctic be nearly sea ice free*?, GEOPHYS. RES. LETT. Pre-Publication copy doi: 10.1002/grl.50316 (Feb. 21, 2013), attached as Exhibit 30.

[192] A. Robinson, et al., *Multistability and critical thresholds of the Greenland ice sheet,* 2 NATURE CLIMATE CHANGE 429 (2012), attached as Exhibit 31.

[193] A. Born and K.H. Nisancioglu, *Melting of Northern Greenland during the last interglaciation*, 6 THE CRYOSPHERE,1239 doi:10.5194/tc-6-1239-2012 (2012), attached as Exhibit 32.

[194] P. Lemke et al., *Chapter 4, Observations: Changes in Snow, Ice and Frozen Ground in* CLIMATE CHANGE 2007: THE PHYSICAL SCIENCE BASIS. CONTRIBUTION OF WORKING GROUP I TO THE FOURTH ASSESSMENT REPORT OF THE INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE 356 (S. Solomon et al. eds., Cambridge Univ. Press 2007), attached as Exhibit 33.

[195] GOVERNMENT ACCOUNTABILITY OFFICE, CLIMATE CHANGE: AGENCIES SHOULD DEVELOP GUIDANCE FOR ADDRESSING THE EFFECTS ON FEDERAL LAND AND WATER RESOURCES 18 (Aug. 2007), *available at*: http://www.gao.gov/news.items/d07863.pdf.

[196] See, e.g., C. Bonfils et al., *Detection and Attribution of Temperature Changes in the Mountainous Western United States*, 21 JOURNAL OF CLIMATE 6404 (2008), attached as Exhibit 34; J.C. Adam et al., *Implications of global climate change for snowmelt hydrology in the twenty-first century*, 23 HYDROL. PROCESS. 962 (2009), attached as Exhibit 35.

[197] U.S. Global Change Research Program, Global Climate Change Impacts in the United States (2009).

the IPCC projections are a substantial underestimate.[198] Studies that have improved upon the IPCC estimates have found that a mean global sea-level rise of at least 1 to 2 meters is highly likely within this century,[199] and larger rates of 2.4 to 4 meters per century are possible.[200] More than half (52%) of US residents live in coastal counties,[201] while an estimated 40% of US endangered species inhabit coastal ecosystems,[202] highlighting the threats of sea-level rise to coastal communities. A nation-wide study estimated that approximately 3.7 million Americans live within one meter of high tide and are at extreme risk of flooding from sea-level rise in the next few decades, with Florida as the most vulnerable state followed by Louisiana, California, New York and New Jersey.[203]

Extreme weather events are striking with increasing frequency, most notably heat waves and rainfall extremes such as droughts and floods,[204] with deadly consequences for people and wildlife. In the United States in 2011 alone, a record 14 weather and climate disasters occurred, including droughts, heat waves, and floods that cost at least US $1 billion each in damages and loss of human lives.[205] There were 11 such events in 2012, with the total cost exceeding that in

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[198] James Hansen et al., *Target atmospheric CO_2: Where should humanity aim*? 2 OPEN ATMOSPHERIC SCIENCE JOURNAL 217 (2008), attached as Exhibit 36; Harnish D Pritchard et al., *Extensive Dynamic Thinning on the margins of the Greenland and Antarctic ice sheets*, 461 NATURE 971 (2009), attached as Exhibit 37; E. Rignot et al., *Acceleration of the contribution of the Greenland and Antarctic ice sheets to sea level rise*, 38 GEOPHYS. RES. LETT. L05503 (2011), attached as Exhibit 38.

[199] S. Rahmstorf et al., *Recent climate observations compared to projections*, 316 SCIENCE 709 (2007), attached as Exhibit 39; W.T. Pfeffer et al., *Kinematic Constraints on glacier contributions to 21st century sea-level rise*, 321 SCIENCE 1340 (2008), attached as Exhibit 40; Martin Vermeer & Stefan Rahmstorf, *Global sea level linked to global temperature*, 106 PROC. NATL. ACAD. OF SCIENCES 21527 (2009), attached as Exhibit 41; Aslak Grinsted et al., *Reconstructing sea level from paleo and projected temperatures 200 to 2100 AD*, 34 CLIMATE DYNAMICS 461 (2010), attached as Exhibit 42; S. Jevrejeva et al., *How will sea level respond to changes in natural and anthropogenic forcings by 2100?*, 37 GEOPHYS. RES. LETT. L07703 (2010), attached as Exhibit 43.

[200] Glenn A. Milne et al., *Identifying the causes of sea-level change*, 2 NATURE GEOSCIENCE 471 (2009), attached as Exhibit 44.

[201] Natl Ocean and Atmospheric Admin, *State of the Coast*, http://stateofthecoast.noaa.gov/population/welcome.html.

[202] O.E. LeDee et al., *The challenge of threatened and endangered species management in coastal areas*, 38 COASTAL MANAGEMENT 337 (2010), attached as Exhibit 45.

[203] B.H. Strauss et al., *Tidally Adjusted estimates of topographic vulnerability to sea level rise and flooding for the contiguous United States*, 7 ENVIRON. RES. LETT. 014033 (2012), attached as Exhibit 46.

[204] Intergovernmental Panel on Climate Change (IPCC), Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation (SREX) (2012), http://ipcc-wg2.gov/SREX/; U.S. Global Change Research Program, Global Climate Change Impacts in the US: Global Climate Change (2009); Dim Coumou & Stefan Rahmstorf, *A Decade of Weather Extremes*, 2 NATURE CLIMATE CHANGE 491 (2012), attached as Exhibit 47.

[205] National Oceanic and Atmospheric Administration, *Extreme Weather 2011*, http://www.noaa.gov/extreme2011/; World Meteorological Organization, *Press Release - 2011: World's*

2011 due primarily to tropical storm Sandy and the year-long drought.[206] Several studies predict that climate change will increase the frequency of high-severity hurricanes in the Atlantic,[207] which would increase the economic damages by $25 billion by 2100 in the United States.[208] Furthermore, Arctic amplification – enhanced global warming at high latitudes – has been associated with increased incidence of drought, flooding, heat waves and cold spells at mid-latitudes.[209]

The oceans have already suffered as a result of greenhouse gas emissions and face a bleak future under "business as usual" emissions scenarios. Ocean warming and acidification are two major climate threats. Through thermal exchange, atmospheric heating affects ocean temperatures, which have been on a continual rise in recent decades. Aside from increasing the severity of storms, this rise in temperature harms ocean ecosystems with effects such as more frequent and extreme coral bleaching events.[210] Oceans have also become over 30% more acidic due to the absorption of carbon dioxide from the atmosphere, with ocean pH predicted to plummet further.[211] Ocean acidification impairs the ability of corals, crabs, abalone, oysters, sea urchins, and other animals to make shells and skeletons.[212] Many species of phytoplankton and zooplankton, which form the basis of the marine food web, also build thick shells that are vulnerable to ocean acidification. Ocean acidification increases the toxicity of harmful algal blooms, or red tides, which are known to kill fish, marine mammals, and even cause paralytic

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10th Warmest Year, Warmest Year with La Niña on Record, Second-lowest Arctic Sea Ice Extent (2012), www.wmo.int/pages/mediacentre/press_releases/gcs_2011_en.html.

[206] National Oceanic and Atmospheric Administration, *Preliminary Info on 2012 U.S. Billion-Dollar Extreme Weather/Climate Events*, http://www.ncdc.noaa.gov/news/preliminary-info-2012-us-billion-dollar-extreme-weatherclimate-events.

[207] James B. Elsner et al., *The Increasing Intensity of the Strongest Tropical Cyclones*, 455 NATURE 92 (2008), attached as Exhibit 48; Morris A. Bender et al., *Modeled Impact of Anthropogenic Warming on the Frequency of Intense Atlantic Hurricanes*, 327 SCIENCE 454 (2010), attached as Exhibit 49; C.M. Kishtawal et al., *Tropical Cyclone Intensification Trends During Satellite Era (1986–2010),* 39 GEOPHYS. RES. LETT. L10810 (2012), attached as Exhibit 50.

[208] Robert K. Mendelsohn et al., *The Impact of Climate Change on Global Tropical Cyclone Damage*, 2 NATURE CLIMATE CHANGE 205 (2012), attached as Exhibit 51.

[209] J.A. Francis and S.J. Vavrus, *Evidence linking Arctic amplification to extreme weather in mid-latitudes*, 39 GEOPHYS. RES. LETT. L06801, doi:10.1029/2012GL051000 (2012), attached as Exhibit 208.

[210] See, e.g., O. Hoegh-Guldberg et al., *Coral reefs under rapid climate change and ocean acidification*, 318 SCIENCE 1737 (2007), attached as Exhibit 53.

[211] K. Caldeira and M.E. Wickett, *Ocean model predictions of chemistry changes from carbon dioxide emissions to the atmosphere and ocean*, 110 J. GEOPHYS. RES. C09S04, doi:10.1029/2004JC002671 (2005), attached as Exhibit 54.

[212] National Research Council, OCEAN ACIDIFICATION: A NATIONAL STRATEGY TO MEET THE CHALLENGES OF A CHANGING OCEAN (2010), attached as Exhibit 55; Royal Society, OCEAN ACIDIFICATION DUE TO INCREASING ATMOSPHERIC CARBON DIOXIDE (2005), attached as Exhibit 56; K.J. Kroeker et al., *Impacts of ocean acidification on marine organisms: quantifying sensitivities and interaction with warming*, GLOBAL CHANGE BIOLOGY pre-publication copy doi:10.1111/gcb.12179 (2013), attached as Exhibit 57.

shellfish poisoning in humans. Many of these effects are already occurring, with predictions that under current emissions trajectories coral and coral-dependent species will be unable to survive by the end of the century, if not before.[213]

Climate change is already having significant impacts on species and ecosystems in all regions of the world, including changes in distribution, phenology, physiology, demographic rates, genetics and ecosystem services, as animals and plants lose their habitats and food sources, struggle to move poleward and upward to keep pace with climate change, and shift their timing of breeding and migration.[214] Climate-vulnerable animals and plants including Arctic sea-ice dependent species (e.g. polar bears, ringed seal), high-elevation species, amphibians, and corals are already experiencing climate-change-related population declines and extirpations.[215] It is predicted that 15%-37% of species will be committed to extinction by 2050 under a mid-level emissions scenario,[216] which the world has been exceeding,[217] and that one in 10 species could face extinction by the year 2100 if current climate change continues unabated.[218] A comprehensive literature review found that significant species range losses and extinctions are predicted to occur globally for coral reef ecosystems and in several biodiversity hotspots at a global mean temperature rise below 2°; at 2°C temperature rise, projected impacts increase in magnitude, numbers, and geographic spread; and beyond a 2°C temperature rise, entire ecosystems may collapse and extinction risk accelerates and becomes widespread.[219]

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[213] See, e.g., T. Abbasi and S.A. Abbasi, *Ocean Acidification: The Newest Threat to the Global Environment*, 41 CRITICAL REVIEWS IN ENVIRONMENTAL SCIENCE AND TECHNOLOGY 1601 (2011), attached as Exhibit 58.

[214] Camille Parmesan & Gary Yohe, *A Globally Coherent Fingerprint of Climate Change Impacts Across Natural Systems*, 421 NATURE 37 (2003), attached as Exhibit 59; Terry L. Root et al., *Fingerprints of Global Warming on Wild Animals and Plants*, 421 NATURE 57 (2003), attached as Exhibit 60; Camille Parmesan, *Ecological and Evolutionary Responses to Recent Climate Change*, 37 ANNUAL REV. OF ECOLOGY EVOLUTION AND SYSTEMATICS 637 (2006), attached as Exhibit 61; I-Ching Chen et al., *Rapid Range Shifts of Species Associated with High Levels of Climate Warming*, 333 SCIENCE 1024 (2011), attached as Exhibit 62; Ilya M. D. Maclean & Robert J. Wilson, *Recent Ecological Responses to Climate Change Support Predictions of High Extinction Risk*, 108 PROC.OF THE NATL. ACAD. OF SCIENCES OF THE U.S. 12337 (2011), attached as Exhibit 63; Rachel Warren et al., *Increasing Impacts of Climate Change upon Ecosystems with Increasing Global Mean Temperature rise*, 141 CLIMATIC CHANGE 106 (2011), attached as Exhibit 64.

[215] *See*, Ex. 61; Simon D. Donner et al., *Model-based Assessment of the Role of Human-induced Climate Change in the 2005 Caribbean Coral Bleaching Event*, 104 PROC. OF THE NAT'L ACAD. OF SCIENCES OF THE U.S. 5483 (2007), attached as Exhibit 65; *See*, Ex. 53; Eric Regehr et al., *Effects of Earlier Sea Ice Breakup on Survival and Population Size of Polar Bears in Western Hudson Bay*, 71 J. OF WILDLIFE MGMT. 2673 (2007), attached as Exhibit 66; Erik A. Beever et al., *Testing Alternative Models of Climate-Mediated Extirpations*, 20 ECOLOGICAL APPLICATIONS 164 (2010), attached as Exhibit 67.

[216] Chris Thomas et al., *Extinction Risk from Climate Change*, 427 NATURE 145 (2004), attached as Exhibit 68.

[217] *See*, Ex. 24; Global Carbon Project, Carbon Budget 2009 (2010).

[218] *See*, Ex. 63.

[219] *See*, Ex. 64.

Climate change also imperils human health through increases in heat waves and other extreme weather events, aliments caused or exacerbated by air pollution and airborne allergens, and the increased occurrence of climate-sensitive infectious diseases.[220] Certain groups such as children, the elderly, the poor, and minorities are particularly vulnerable to climate-related health effects.[221] Heat is already the leading cause of weather-related deaths in the United States, and a recent study estimated that more than 150,000 Americans may die by the end of the century due to excessive heat caused by climate change.[222] Extreme precipitation, which has increased in the Midwest, South and other regions by 50% mostly over the last few decades,[223] poses significant human health risks including contaminated drinking water leading to disease outbreaks, drowning, and mold-related illnesses.[224] Air pollution components that trigger asthma attacks, specifically air particulates and ozone, are expected to increase with climate change.[225] Infectious diseases also pose an increased threat in a changing climate. There are an estimated 38 million cases of food and water-borne illness in the US each year, caused in part by an increasing number of pathogens in the wake of extreme weather events such as droughts, flooding, and hurricanes.[226] A recent study suggests that outbreaks of the vector-borne West Nile Virus are potentially related to higher summer temperatures and extreme variation in precipitation.[227]

Climate change affects food security through a number of complex pathways, both direct and indirect, including the reduced ability of crops to thrive, increased threats to livestock, climate-related contamination of food supplies, and an alteration in land use patterns and availability. Higher levels of warming and extreme weather events such as droughts and flooding are expected to negatively affect the growth and yields of many crops.[228] Warming will benefit weeds, diseases, and insect pests, increasing stress on crop plants and requiring more pest and

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[220] U.S. Global Change Research Program, Global Climate Change Impacts in the United States (2009).
[221] *Id.*
[222] Natural Resources Defense Council, KILLER SUMMER HEAT: TOLL FROM RISING TEMPERATURES IN AMERICA DUE TO CLIMATE CHANGE (2012), *available at* http://www.nrdc.org/globalwarming/killer-heat/files/killer-summer-heat-report.pdf.
[223] U.S. Global Change Research Program, Global Climate Change Impacts in the United States (2009).
[224] Union of Concerned Scientists, AFTER THE STORM: THE HIDDEN HEALTH RISKS OF FLOODING IN A WARMING WORLD (2012), *available* at www.ucsusa.org/global_warming/science_and_impacts/impacts/global-warming-and-flooding.html.
[225] A. Bernstein & S.S. Myers, *Climate Change and Children's Health*, 23 CURRENT OPINION IN PEDIATRICS 221 (2011), *available at* http://journals.lww.com/co-pediatrics/Fulltext/2011/04000/Climate_change_and_children_s_health.16.aspx#, attached as Exhibit 69.
[226] E. Maibach et al., Center for Climate Change Communication, CONVEYING THE HUMAN IMPLICATIONS OF CLIMATE CHANGE, 10-11 (2011), *available at* http://www.climatehealthconnect.org/resource/conveying-human-implications-climate-change-climate-change-communication-primer-public-heal.
[227] Shlomit Paz, *West Nile Virus Eruptions in Summer 2010 – What Is the Possible Linkage with Climate Change?*, Chapter 21 of NATIONAL SECURITY AND HUMAN HEALTH IMPLICATIONS OF CLIMATE CHANGE 253 – 260 (2012), *available at* http://www.springerlink.com/content/978-94-007-2430-3#section=1013683&page=2&locus=0, attached as Exhibit 70.
[228] U.S. Global Change Research Program, Global Climate Change Impacts in the United States (2009).

weed control.[229] Increasing CO_2 concentrations are expected to lead to declines in forage quality in pastures and rangelands for livestock, while increased heat, disease, and weather extremes will increase livestock mortality.[230] Temperature increases, changes in rainfall, and extreme weather events are also expected to increase the incidence and intensity of food-borne diseases and food contamination, jeopardizing food security. [231]

We are already experiencing dangerous climate change, but catastrophe may still be avoidable with rapid and immediate reductions in both short-lived climate pollutants and carbon dioxide.[232] The consensus is that we must aim to return carbon dioxide concentrations to no more than 350 ppm to avoid the worst consequences.[233] Every action we take must be evaluated with a full understanding of the necessity of immediate emissions reductions and the dire consequences of failing to make those reductions.

b. The DSEIS Fails to Adequately Analyze Keystone XL's Climate Change Impacts

The DSEIS fails to adequately analyze the impacts of the proposed project's greenhouse gas emissions on climate change as required by NEPA. "The impact of greenhouse gas emissions on climate change is precisely the kind of cumulative impacts analysis that NEPA requires agencies to conduct." *Center for Biological Diversity v. National Highway Traffic Safety Administration*, 508 F.3d 508, 550 (9th Cir. 2007)); *Mid States Coaliton for Progress v. Surface Transportation Board*, 345 F.3d 508 (9th Cir. 2008); *Border Power Plant Working Group v. DOE*, 260 F.Supp 2d 997 (S.D. Cal. 2003). The courts also underscore the need to analyze climate change when the proposed action is regional or national in scope, which is clearly the case for the proposed project which extends from Canada through several U.S. states.

Moreover, NEPA calls for a quantification of the "incremental impact[s] that [the proposed project's] emissions will have on climate change … in light of other past, present, and reasonably foreseeable actions." *Ctr. for Biological Diversity v. Nat'l Highway Traffic Safety Admin.*, 538 F.3d 1172, 1216 (9th Cir. 2008). This is true "regardless of what agency or person undertakes such other actions." Id. Even if a proposed project has an "individually minor" effect on the environment, this and other such actions are "collectively significant actions taking place over a period of time." 40 C.F.R. § 1508.7; *see also Native Ecosystems Council,* 304 F.3d at 897

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229 *Id.*
230 *Id.*
231 M.C. Tirado et al., *Climate Change and Food Safety: A Review*, 43 ELSEVIER 1745 (2010), *available at* www.elsevier.com/locat/foodres, attached as Exhibit 71.
232 *See*, e.g., S.J. Davis et al., *Rethinking Wedges*, 8 ENVIRON. RES. LETT. 011001 (2013), attached as Exhibit 72; H.D. Matthews and S. Solomon, *Irreversible Does Not Mean Unavoidable*, SCIENCEEXPRESS doi: 10.1126/science.1236372 (April 1, 2013), attached as Exhibit 73; D. Shindell et al., *Simultaneously Mitigating Near-Term Climate Change and Improving Human Health and Food Security,* 335 SCIENCE 183 (2012), attached as Exhibit 74.
233 *See*, e.g., Ex. 36.

(holding that the Forest Service's road density standard amendments must be subject to cumulative impacts analysis because otherwise, "the Forest Service will be free to amend road density standards throughout the forest piecemeal, without ever having to evaluate the amendments' cumulative environmental impacts."); *City of Los Angeles v. NHTSA*, 912 F.2d 478, 501 (D.C.Cir.1990) (Wald, C.J., dissenting) ("[W]e cannot afford to ignore even modest contributions to global warming. If global warming is the result of the cumulative contributions of myriad sources, any one modest in itself, is there not a danger of losing the forest by closing our eyes to the felling of the individual trees?"), *overruled on other grounds by Fla. Audubon Soc. v. Bentsen*, 94 F.3d 658 (D.C.Cir.1996). NEPA requires analysis of the "actual environmental effects resulting from those emissions." *Ctr. for Biological Diversity v. Nat'l Highway Traffic Safety Admin.*, 538 F.3d 1172, 1216 (9th Cir. 2008). Accordingly, the DSEIS must quantify and evaluate the cumulative and incremental effects of climate change resulting from the proposed project and connected actions in comparison to and in conjunction with the effects of emissions of other reasonable alternatives or actions – past, present and reasonably foreseeable.

The DSEIS compares the quantity of greenhouse gas emissions resulting from construction and operation of the pipeline with the greenhouse gas emissions from alternative means of transporting tar sands. It also analyzes the effects of climate change on the project. However, the DSEIS is flawed because it fails to analyze the actual climate change effects of the proposed project, connected actions and alternative modes of transport would have on the environment, including effects on wildlife, water resources and other natural resources and human health. Moreover, the DSEIS is further flawed because of its failure to consider alternatives other than modes of fuel transport, such as a cleaner fuels and energy conservation alternative. By rejecting the cleaner fuels alternative, no complete analysis exists comparing the greenhouse gas emissions and climate change effects of that alternative to the proposed project. As set forth above, this sort of analysis is not beyond the scope of what NEPA requires as the DSEIS erroneously asserts.[234] The local, regional and global environmental impacts of life-cycle CO_2 emissions from the proposed Keystone XL pipeline and related actions must be evaluated. This includes a discussion of the serious and irreversible impacts on climate, sea level, ocean acidification, biodiversity, and subsequent impacts on society. Simply indicating that those emissions would occur in any case does not satisfy NEPA requirements to distinctly consider the potential environmental impacts of specific actions taken by the U.S.

By failing to properly conduct climate change impacts analyses the DSEIS falters in the same way that NHTSA did in evaluating proposed Corporate Average Fuel Economy Standards (CAFE), that the Surface Transportation Board did in evaluating the construction and upgrade of a railroad track carrying low sulfur coal to the Midwest, and that the BLM did in evaluating impacts of harvest on a watershed. All of these agency analyses were invalidated by the courts for failing to assess the cumulative effects of the alternatives on various resources, such as wildlife, water quantity, and soils. *Center for Biological Diversity v. NHTSA*, 508 F.3d 508; *Klamath Siskiyou Wildlands Center v. Bureau of Land Management*, 387 F.3d 989, 994 (9th Cir.

[234] DSEIS, at 4.15-79

2004); *Mid States Coalition for Progress v. Surface Transportation Board*, 345 F.3d 520, 550 (8th Cir. 2003). Similarly, the State Department simply projects the relative emissions of various transportation modes and fails to evaluate the climate change effects of the proposed project, connected actions and alternative modes of transport. As such, the analysis is arbitrary and capricious.

c. The DSEIS' Assumption that GHG Emissions Would Occur at the Same Rate Regardless of Keystone XL is Arbitrary and Capricious

The DSEIS' estimation of the GHG emissions associated with Keystone XL is based on the same flawed assumption that persists throughout the DSEIS- the tar sands will be developed at the same rate regardless of whether Keystone XL is built. Using that rationale, the DSEIS is able to ignore the GHG emissions associated with increasing tar sands development. For example, the DSEIS states:

> *Based upon the market analysis in Section 1.4*, the incremental life-cycle emissions associated with the proposed Project are estimated in the range of 0.07 to 0.83 million metric tons carbon dioxide equivalent (MMTCO2e) annually if the proposed Project were not built, and in the range of 0.35 to 5.3 MMTCO2e annually if all pipeline projects were denied..."[235]

As set forth in detail in PartII.D.1 of these comments, the State Department's conclusion that Keystone XL will not cause increased tar sands development is arbitrary and capricious, and is contradicted by a wealth of evidence. Therefore, the DSEIS GHG analysis that is based on this premise is fatally flawed because it results in a substantial underestimation of the project's climate change impacts.

d. The Life Cycle Greenhouse Gas Assessment for Keystone XL Is Inadequate and Flawed

The DSEIS includes an analysis of the lifecycle GHG emissions (Appendix W and summarized in pp. 4.15-78 – 4.15-107) based on work by the consulting firm ICF. The assessment correctly states that oil from tar sands has higher lifecycle GHG emissions than conventional oils, and gives a reasonably thorough explanation of the factors that cause different conclusions about lifecycle greenhouse gas emissions of tar sands compared to other "reference crudes." However, the conclusion that "Across all reference crude types, the results show a 2 to 19 percent increase in Well-to-Wheel ("WTW) GHG emissions from the weighted-average mix of oil sands crudes expected to be transported in the proposed Project relative to the reference crudes in the near term," is flawed and misleading.[236] First, these numbers fail to capture a significant amount of the incremental emissions of the pipeline. Second, the analysis does not

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[235] *Id.* (emphasis added)
[236] DSEIS, Appendix W at 60.

provide an emissions estimate for the difference between the bitumen that would flow through the pipeline versus conventional crude – an analysis which is merited due to possible market conditions. Finally, these numbers fail to account for the total greenhouse gas emissions associated with the Keystone XL pipeline, a critical factor in ensuring a future that avoids catastrophic climate change.

i. The 2-19% range fails to capture many of the incremental emissions

The State Department provides a clear explanation for the choice of studies used to provide this range and what this range means, the deficiencies of each study, and how each study was used to contribute to Tables 6-2, 6-3, and 6-4, and Figure 6-1 in Appendix W. But, in providing the emissions range of 2-19%, it does not attempt to account for several major emissions sources it acknowledges are not included in the studies. Under NEPA, the State Department is required to consider the "cumulative impact," of a project – that is, "the impact on the environment which results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (Federal or non-Federal) or person undertakes such actions."[237] It also must consider "Indirect effects, which are caused by the action and are later in time or farther removed in distance but are still reasonably foreseeable."[238] For example, *none* of the three studies used to come to the 2-19% range included the emissions from incorporating capital equipment, or indirect land use change.[239] The DSEIS acknowledges that "the relative percentage increase to WTW GHG emissions from incorporating capital equipment is between 9 and 11 percent" and that "potential GHG emissions impacts of including land use change emissions estimate potential increases in WTW GHG emissions for oil sands range from less than 1 to 3 percent."[240] While there are a number of other factors to be considered that could both increase and decrease the difference between the tar sands that would flow through Keystone XL and reference crudes, in theory, this could mean that tar sands that would flow through Keystone XL cause as much as 33% more GHG emissions than reference crudes (19% + 11% + 3%). The State Department should come up with a more accurate estimate that accounts for these emissions that they have acknowledged are not included in the studies they have chosen to use as the basis for this 2-19% calculation.

ii. The State Department should additionally provide an incremental emissions analysis for bitumen versus reference crudes

In addition to calculating the emissions difference between the likely blend that would run through the pipeline and. reference crudes, the State Department should provide analysis of the difference in emissions between the bitumen that could run through the pipeline and reference crudes. There is no requirement that the pipeline carry a 50-50 mix of dilbit and

[237] 42 U.S.C. 4371 et seq. Sec. 1508.7 http://ceq.hss.doe.gov/nepa/regs/ceq/1508.htm
[238] 42 U.S.C. 4371 et seq. Sec. 1508.8 http://ceq.hss.doe.gov/nepa/regs/ceq/1508.htm
[239] DSEIS, Appendix W at 38.
[240] DSEIS, Appendix W at 41.

synthetic crude oil ("SCO"), as assumed in the DSEIS; it is not out of the question that the pipeline could transport all, or almost all dilbit, as Alberta's upgrading capacity is running short. Further, it is possible – due to the increase in production from tight oil formations – that with or without Keystone XL, the Gulf refineries could take in an amount of light sweet crudes comparable to the amount of diluent that would flow through Keystone XL. At 830,000 bpd, and assuming 70% bitumen and 30% diluent, there could be as much as 581,000 bpd of bitumen flowing through Keystone XL. According to the DSEIS, "all WCSB dilbit is currently produced using in situ production" that "all bitumen produced from mining is upgraded into SCO."[241] It is thus reasonable to expect that this bitumen would be produced by in situ methods, which tend to have higher emissions than mining as we can tell from emissions comparisons of in situ SCO to mining SCO in the SDEIS.[242] However, the State Department only considers in situ dilbit – not in situ bitumen – so that it is not feasible from reading the SEIS to separate out the emissions caused by the bitumen versus the emissions caused by the diluent.

iii. The State Department should analyze the *total* lifecycle GHG implications from Keystone XL, not just the incremental difference between tar sands and reference crudes.

Today's reality is that we live in a world with a rapidly changing global climate. Scientists have stated that we need to keep the majority of the remaining fossil fuel reserves in the ground, and that we have a limited global carbon budget remaining to have a chance at avoiding catastrophic climate change. A lifecycle analysis of Keystone XL should therefore include not only the information about the difference between the tar sands that would flow through the pipeline and other crudes currently being processed in the U.S. and globally, but also an analysis of the *total* greenhouse gas emissions related to the project, including the combustion of the refined product.

e. The DSEIS Makes Incorrect Assessments of Emissions from Combusting Petroleum Coke

The DSEIS acknowledges that "the treatment of petroleum coke in (Life Cycle Assessment) studies [is] an important factor that influences the life-cycle GHG emission results."[243] However, as with the 2011 FSEIS, the State Department makes incorrect assessments of the actual emissions from combusting petroleum coke derived from Canadian tar sands bitumen.

With regards to bitumen that is upgraded in Canada and associated with SCO production, the State Department states that 50-75 percent is stockpiled in Alberta and therefore not

[241] DSEIS Appendix W p. 58
[242] DSEIS Appendix W p. 60
[243] DSEIS, at 4.15-94.

combusted.[244] The State Department cites Alberta ERCB 2010 data and Oil Change International 2013. The Oil Change International report cites Alberta ERCB data for 2011 that shows a marked decrease in the stockpiling of upgrader-produced petroleum coke from 75 percent in 2010 ERCB to 50 percent in the 2011 data.[245] It also cites industry sources that note that exports of petroleum coke from the west coast of Canada to Asia have been increasing.[246]

The State Department should use the latest data in assessing the level of petroleum coke associated with SCO production as well as review trends in petcoke exports from Canada's west coast. These suggest that an increasing proportion of petroleum coke associated with SCO production is making its way to market to be combusted. This raises the emissions associated with SCO production from previous assessments that assume that the majority of this petroleum coke is stockpiled.

The State Department additionally makes an assessment of petroleum coke produced at Gulf Coast refineries from bitumen blends that appears to be pure speculation. Namely, that Latin American heavy oils that the State Department assumes will be backed out by bitumen blends delivered by the Project[247], will be shipped to China and the residual oil produced from them at Chinese refineries will be used instead of coal to generate electricity in China.[248] The State Department discusses this elaborate scenario with no reference to any source whatsoever. This assumption requires greater basis in fact to be taken seriously.

Lastly, the State Department continues to assume, via the LCA studies it uses to assess the GHG intensity of tar sands production, that petroleum coke simply replaces coal in the market one-for-one and therefore emissions from petroleum coke combustion need not be factored into the GHG analysis of tar sands production and consumption. This ignores that fact that petroleum coke is dumped into the market by refiners at a substantial discount to coal. The Oil Change International report explains how this can save coal-fired power generators hundreds of millions of dollars a year in fuel costs through co-firing petroleum coke with coal.[249] Basic laws of economics would suggest that this can only serve to support the economics of coal-fired power generation over other cleaner sources. No assessment of this has been made by the State Department and the status quo of dismissing petroleum coke emissions is maintained. This means that GHG emissions from combusting the refined products from tar sands bitumen are underestimated in the DSEIS. While we agree with the State Department that this is an issue that

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[244] DSEIS, at 4.15-99.
[245] Oil Change International, "Petroleum Coke: The Coal Hiding in the Tar Sands." January 2013. Pages 21-22 http://priceofoil.org/wp-content/uploads/2013/01/OCI.Petcoke.FINALSCREEN.pdf
[246] "Energy Publishing, LLC's Domestic and International Petcoke Report", September 2012, "Ridley exports up significantly". (Subscription Only)
[247] We dispute the assumption that Latin American crudes will be backed out in comments on the Market Analysis section.
[248] DSEIS, at 4.15-100.
[249] Oil Change International, *supra* at 34.

also relates to other sources of heavy oil, it is crucial to include a full accounting of GHG emissions in any assessment of hydrocarbon production and consumption.

f. The DSEIS Fails to Consider the Climate Impacts of Short-lived Climate Pollutants

The climate impacts assessment in the DSEIS is inadequate because it omits any consideration of the climate impacts of short-lived climate pollutants (SLCPs) emitted by the proposed project. National and international attention increasingly has focused on the health and climate effects and potential for mitigation of SLCPs. For instance, the U.S. State Department was integral to the formation of the Climate and Clean Air Coalition to Reduce Short-Lived Climate Pollutants, which focuses on reducing black carbon, methane, and HFCs.[250] Furthermore, The United States also has an obligation under the Gothenburg Protocol to address black carbon pollution.[251]

Short-lived climate pollutants are essential to near-term climate change mitigation and avoidance of tipping points. These pollutants are potent climate forcers with atmospheric lifetimes of days to decades. Thus, reductions in emissions result in nearly immediate decreases in radiative forcing. As atmospheric carbon dioxide concentrations continue to rise, the role that SLCPs can play in mediating climate change impacts becomes increasingly important. This is especially true with regard to tipping points in the climate system. The courts have expressed particular concern that NEPA analyses consider the non-linear aspect of "irreversible adverse climate change" or "tipping points" wherein a seemingly small change in emissions can evoke a dramatic climate response.[252] SLCPs and carbon dioxide affect climate change over different time scales and through varying mechanisms; thus, it is essential that an environmental impacts analysis consider the emissions of both categories of climate pollutants.

Because the effect of reducing SLCPs is nearly immediate – in contrast to reductions in carbon dioxide – mitigation of these pollutants can stave off the worst effects of climate change

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[250] The DSEIS states that State Department is involved in the Climate and Clean Air Coalition to Reduce Short-Lived Climate Pollutants, yet there is no analysis of the way in which emissions from this project would impede this initiative. See DSEIS, at 3.12-21.

[251] UNECE, Protocol to Abate Acidification, Eutrophication and Ground-level Ozone done in Gothenburg, Sweden in 1999 (last visited August 31, 2012), *available at* http://www.unece.org/env/lrtap/multi_h1.html. The Gothenburg Protocol is part of the Convention on Long-Range Transboundary Air Pollution. The United States has ratified this treaty. The Gothenburg Protocol sets particulate matter ceilings for European countries, although the United States is not subject to these ceilings. On May 4, 2012 the Protocol was amended to specifically address black carbon as a constituent of fine particulate matter. These revisions to the Protocol emphasize the importance of reducing black carbon to protect public health and climate.

[252] *Center for Biological Diversity v. National Highway Traffic Safety Administration*, 538 F.3d 1172, 1221 (9th Cir. 2008).

and reduce the chances that Earth will experience tipping points.[253] Conversely, increases in these pollutants can exacerbate climate change due to their large potential near-term effect. Several "tipping elements" in the climate system are thought to be close to their triggering points. For example, a 0.8 to 3.2°C temperature rise above pre-industrial levels has the potential to trigger irreversible melting of the Greenland ice sheet, resulting in an eventual seven meters of sea-level rise that would inundate small island nations and heavily populated coastal areas.[254] Climate forcing from rising greenhouse gas emissions also reinforces vicious climate feedback cycles that can further amplify warming. In the Arctic, the ice-albedo feedback loop is already occurring, where the loss of highly reflective sea ice due to warming increases solar absorption, making the Arctic more vulnerable to future warming and ice loss. In fact, it is estimated that the Arctic Sea will be ice-free in the summer within the next decade or two.[255] Increasing temperatures are expected to trigger other feedbacks including the release of large stores of carbon and the potent greenhouse gas methane from melting Arctic permafrost.[256]

The United Nations Environment Programme recently released an assessment report that outlined the importance of reductions in SLCPs (black carbon, ozone and methane) for protecting public health and staying within the world's commitment to keep global temperature changes below 2° C.[257] The identified mitigation strategies *if implemented by 2030* could cut global temperature increases in half by 2050.[258] A recent study indicated that SLCP reductions must begin in 2015 to be maximally effective, and that such immediate reductions could not only mitigate rising temperature but also reduce potential sea level rise by 31 to 50%.[259]

The proposed project has the potential to emit significant volumes of SLCPs. Diesel engines, fuel usage and open combustion are two major sources of black carbon, both of which will be involved in construction of the pipeline. Fugitive methane emissions from the pipeline will be a direct impact from the project, and fugitive methane emissions from oil extraction, storage and usage will be indirect impacts. Consequently, the NEPA analysis is inadequate due to its failure to consider these emissions.

i. Black carbon climate impacts and emissions must be analyzed and quantified in the DSEIS

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[253] *See*, e.g., J. Hansen et al., *Climate Change and Trace Gases*, 365 PHIL. TRANS. R. SOC. A 1925 (2007), attached as Exhibit 75.
[254] *See*, Ex. 31.
[255] *See*, Ex. 30.
[256] David Archer et al., The Millennial Atmospheric Lifetime of Anthropogenic CO_2, 90 Climatic Change 283, 22 (2008), attached as Exhibit 76; Charles D. Koven et al., Permafrost carbon-climate feedbacks accelerate global warming, 108 Proc. Natl. Acad. of Sciences 14769 (2011), attached as Exhibit 77.
[257] United Nations Environment Program (UNEP), INTEGRATED ASSESSMENT OF BLACK CARBON AND TROPOSHERIC OZONE (2011) [hereinafter "UNEP SLP Report 2011"].
[258] Id. at 159.
[259] A. Hu et al., *Mitigation of short-lived climate pollutants slows sea-level rise*, NATURE CLIMATE CHANGE pre-publication doi: 10.1038/NCLIMATE1869 (2013), attached as Exhibit 78.

The DSEIS fails to assess the impacts of black carbon emissions from the proposed project. Black carbon, a component of $PM_{2.5}$, is a potent short-lived pollutant[260] with climate impacts that may be second only to carbon dioxide over the next 20 years.[261] The 100-year global warming potential (GWP) for black carbon is estimated to be 900, while the 20-year GWP is estimated to be 3200.[262] Black carbon, or soot, is a product of incomplete combustion. It is typically co-emitted with organic carbon; the ratio of black carbon to organic carbon is highest for fossil fuels.

Black carbon's climate forcing is the result of several mechanisms. First, black carbon directly heats the atmosphere as soot particles absorb incoming radiation. Second, black carbon particles reduce the albedo, or reflectivity, of snow and ice, with the result that less incoming radiation is reflected away from Earth.[263] When black carbon falls on snow and ice surfaces, either on its own or within ice crystals or snow flakes, it darkens those surfaces, thereby contributing to the melting of snow and ice and the warming of air above both[264], especially in polar regions.

Black carbon also nucleates clouds, increasing cloud droplet concentrations and thickening low-level clouds that trap more of the Earth's radiated heat.[265] (Black carbon is a significant component of Arctic haze.) Moreover, the radiative forcing of suspended black carbon particles is thought to be amplified at the poles, where there is more light reflected from the Earth's surface, and thus more light available for the black carbon particles to absorb. Most black carbon that is deposited in the Arctic originates as fuel combustion by-products emitted in northern hemisphere in Eurasia and North America, primarily north of 40º latitude.[266]

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[260] Black carbon remains in the atmosphere for about one week.
[261] Ramanathan and Carmichael report an observationally constrained value of direct radiative forcing for black carbon of 0.9 W/m^2 (V. Ramanathan, & G. Carmichael, Global and Regional Climate Changes due to Black Carbon, 1 Nature Geoscience at 221 (2008), attached as Exhibit 79). Methane, the second most potent well-mixed greenhouse gas has a radiative forcing of 0.48 W/m^2 according to the IPCC Fourth Assessment. Emissions-based estimates for methane's climate forcing are higher (0.99 W/m^2) (D. Shindell et al., *Improved Attribution of Climate Forcing to Emissions*, 326 SCIENCE 716 (2009), attached as Exhibit 80).
[262] T.C. Bond et al., *Bounding the role of black carbon in the climate system: A scientific assessment*, J. GEOPHYS. RES. Pre-publication copy doi: 10.1002/jgrd.50171 (2013), attached as Exhibit 81. GWP values estimated for black carbon vary widely, although this study is the most recent, comprehensive estimate.
[263] *See, e.g.*, James Hansen & Larissa Nazarenko, *Soot Climate Forcing via Snow and Ice Albedos*, 101 PROC. NAT'L ACAD. SCI. U.S. 423, 427 (2004), *available at* http://www.pnas.org/content/101/2/423.full, attached as Exhibit 82.
[264] *See*, Ex. 79; *EPA Black Carbon and Global Warming: Hearing Before the H. Comm. on Oversight and Gov't. Reform*, 110th Cong. 12-29 (2007) [hereinafter *Hearing*] (statement of Mark Z. Jacobson, Professor, Stanford University) at 16, attached as Exhibit 83.
[265] *Id.*
[266] *Id.*

The deposition of black carbon on snow and ice also affect the hydrological cycle. Black carbon increases the melting rate of glaciers and seasonal snow pack. Glacial water storage and release has important implications for hydroelectric power plants, irrigation, consumptive use, and local ecosystems.[267] Similarly, many areas of the United States rely on late-season melt of seasonal snowpack to provide a constant water supply. Several studies have documented the changes in seasonal water availability that occur due to black carbon deposition, especially in the Alberta and the Rockies. [268]

Black carbon is released into the atmosphere from the incomplete combustion of fossil fuels, biofuels and biomass. Black carbon emissions result mainly from four source categories: (1) diesel engines for transportation and industrial use; (2) residential solid fuels such as wood and coal; (3) open forest and savanna burning, both natural and initiated by humans for land clearing; and (4) industrial processes, usually from small boilers.[269] The top two U.S. sources of net climate forcing black emissions according to the Environmental Protection Agency are non-road diesel and on-road diesel.

The myriad on and off-road diesel vehicles[270], generators, construction equipment and earth moving equipment associated with construction of the pipeline and related facilities, tar sands extraction, as well as the tar sands plants in Alberta, are all significant sources of particulate matter, and thus black carbon, emissions. As they are all located above 40 degrees latitude, they are of particular concern because these emissions are the major source of black carbon deposition in the Arctic. Furthermore, the proposed land clearing through brush burning would be a source of black carbon. Indirect emissions will occur as a result of combustion of fuels produced from Canada's tar sands, especially petroleum coke products that are used in China. Even where $PM_{2.5}$ emissions are noted, for example from diesel construction equipment, the DSEIS fails to assess the significant climate forcing effect of the black carbon fraction of

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[267] R.D. Moore et al., *Glacier Change in Western North America: Influences on Hydrology, Geomorphic Hazards and Water Quality.* 23 HYDROLOGICAL PROCESSES 42 (2009), attached as Exhibit 84.

[268] See, e.g., O. L. Hadley et al., *Measured black carbon deposition on the Sierra Nevada snow pack and implication for snow pack retreat*, 10 ATMOS. CHEM. PHYS. 7505 (2010), attached as Exhibit 85; Y. Qian et al., *Effects of soot-induced snow albedo change on snowpack and hydrological cycle in western United States based on Weather Research and Forecasting chemistry and regional climate simulations*, 114 J. GEOPHYS. RES. D03108 (2009), attached as Exhibit 86.

[269] *Hearing*, *supra* note 264 (statement of Tami Bond, Assistant Professor, University of Illinois at Urbana-Champaign) at 33, attached as Exhibit 87.

[270] Chung and colleagues recently reported observational estimates of direct radiative forcing for both black carbon and organic matter from biomass burning. They estimate direct radiative forcing for black carbon to be 0.65 W/m^2 and the contribution of organic carbon to be 0.0 W/m^2 due to the offsetting balance of absorption by brown carbon and light scattering (S. Chung et al., *Observationally constrained estimates of carbonaceous aerosol radiative forcing*, 109 PROC. NATL. ACAD. SCI. 11624, 11627 (2012), attached as Exhibit 88). Furthermore, these authors estimate that indirect effects approximately cancel as well, with the result that the black carbon forcing will dictate the forcing from pollutants emitted by biomass burning.

those emissions – the Environmental Protection Agency estimates the black carbon fraction of diesel $PM_{2.5}$ emissions to be over 60% on average.

The DSEIS must consider each of these sources of black carbon to adequately assess climate impacts of the proposed project. Black carbon emissions can be quantified through use of existing source-specific inventories and conversion factors.[271]

ii. Methane emissions from the project have been underestimated

Although the DSEIS briefly considers methane emissions, the analysis fails to fully account for climate impacts from methane. Methane is the second most potent well-mixed greenhouse gas behind carbon dioxide, although as discussed above the radiative forcing of methane may be lower than that of black carbon. Methane is considered to have an atmospheric lifetime of about a decade. It exerts direct climate effects as a greenhouse gas as well as through tropospheric ozone, for which it is a precursor. Like black carbon, methane is also important in the Arctic, which is particularly sensitive to methane-induced ozone formation. [272] A major source of methane is oil extraction, transport and processing.[273]

Beyond the climate impacts of methane, public health is strongly affected by ozone formed from methane. In fact, it has been estimated that methane reductions are an essential component of protecting public health, and can be achieved at a net cost benefit.[274]

The DSEIS underestimates the climate impacts of methane released from the proposed project because it uses an inaccurate global warming potential (GWP). When computing the contribution of methane to the total emissions of the proposed project, the DSEIS assumes that methane is 21 times more powerful than carbon dioxide. The IPCC, however, gives a value of 25 for the 100-year GWP of methane.[275] When aerosol interactions are included, the 100-year GWP for methane is estimated at 33, but may be closer to 45.[276] Thus, the GWP of 21 uses in the DSEIS is certainly an underestimate of methane's climate impacts.

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[271] See, e.g., T.C. Bond et al., *A technology-based global inventory of black and organic carbon emissions from combustion*, 109 J. GEOPHYS. RES. D14203 (2004), attached as Exhibit 89.
[272] See, e.g., P.K. Quinn et al., *Short-lived pollutants in the Arctic: their climate impact and possible mitigation strategies*, 8 ATMOS. CHEM. PHYS. 1723 (2008), attached as Exhibit 90.
[273] US EPA, DRAFT INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS: 1990 – 2011 (Feb. 11, 2013). Petroleum systems were the sixth largest source of methane in the United States in 2011, emitting 31.5 MMT CO_2eq.
[274] J.J. West et al., *Global health benefits of mitigating ozone pollution with methane emission controls,* 103 PNAS 3988 (2006), attached as Exhibit 91.
[275] P. Forster et al., *Chapter 2: Changes in Atmospheric Constituents and in Radiative Forcing in* CLIMATE CHANGE 2007: THE PHYSICAL SCIENCE BASIS. CONTRIBUTION OF WORKING GROUP I TO THE FOURTH ASSESSMENT REPORT OF THE INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE Table 2.14 (S. Soloman et al. eds., Cambridge University Press 2007), attached as Exhibit 92.
[276] *See*, Ex. 80.

Furthermore, the DSEIS should be considering a 20-year GWP for short-lived pollutants such as black carbon and methane. Because these pollutants are present in the atmosphere for a short duration, their effects are much greater when assessed over shorter time scales. For instance, the IPCC's Fourth Assessment Report estimated that methane has 72 times the global-warming potential of carbon dioxide over a 20-year period.[277] More complete estimates of total methane forcing, however, indicate that the 20-year global warming potential is over 100.[278] These more accurate GWP values are essential to properly analyzing the impacts of methane emissions from the project.

The DSEIS must be updated to reflect the higher, more accurate 100-year GWP for methane as well as an analysis must be conducted using the 20-year GWP to assess how these emissions may affect the probability of reaching near-term tipping points.

g. The State Department Must Postpone Further Review of the Keystone XL Pipeline in Order to Incorporate CEQ's Greenhouse Gas and Climate Change Guidance

The Council on Environmental Quality is expected to issue greenhouse gas and climate change guidance for NEPA imminently. In light of CEQ's anticipated GHG NEPA guidance, and the greenhouse gas emissions and increased tar sands extraction that would result from the proposed project and connected actions, the State Department has an obligation to postpone consideration of the Keystone XL application in making its national interest determination.

Over its entire lifecycle – the synthetic crude oil produced from tar sands emits at least 17% more global warming pollution than conventional oil. Furthermore, because tar sands oil is a heavier crude, the U.S. refineries that process it will produce higher levels of pollutants that damage human health and lead to more smog, haze and acid rain. Replacing 830,000 barrels per day of conventional oil with tar sands oil, for example, would result in approximately 38 million metric tons of additional greenhouse gas emissions per year, equal to adding over 6 million cars to our roads. The U.S. transportation sector already accounts for one third of our global warming emissions. These aspects of the project must be given a more thorough analysis in the EIS, and the preparers would benefit from CEQ's final guidelines.

In a February 2010 memorandum to heads of Federal Departments and Agencies, CEQ Chair Nancy Sutley affirmed that the requirements of NEPA are applicable to greenhouse gas emissions and climate change impacts.[279] A draft of these guidelines already was released by CEQ.[280] Further, a March 15, 2013 Bloomberg article discussing the impacts of the new guidance on federal agency review of projects that would have climate change effects stated that

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[277] *See*, Ex. 92.
[278] *See*, Ex. 80.
[279] CEQ Chairwoman Nancy Sutley, "Steps to Modernize and Reinvigorate NEPA." *Available at* www.whitehouse.gov/administration/eop/ceq/initiatives/nepa (last visited June 8, 2010).
[280] 75 Fed. Reg. 8046 (Feb. 23, 2010).

the federal government will be issuing the guidance imminently.[281] As such, the State Department should postpone further review of the proposed pipeline project until the final guidelines can be diligently reviewed and incorporated. In the alternative, if the State Department decides to proceed prior to CEQ's issuance of the guidance, the State Department must incorporate the draft guidance into its analysis to ensure a more complete assessment of the global warming impacts of the proposed project and a reasonable range of alternatives.[282]

h. The DSEIS Fails to Consider Climate Impacts in the Context of Avoiding a Climate Disaster

Arguing that if the project is denied, other takeaway capacity will largely substitute for it, the DSEIS estimates that denying the pipeline would only decrease tar sands production by 20,000 – 30,000 barrels per day by 2030 (4.15-106). The DSEIS assumes tar sands production will be around five million barrels per day by then (4.15-56). From a human perspective, this is an extreme scenario. The International Energy Agency's Chief Economist Fatih Birol characterizes this scenario as having "catastrophic implications".[283] In the well-known "burning embers" chart, the projected temperature increase corresponding to the scenario featuring this level of tar sands production is at the very top or literally off the chart, cf. figure 7.[284]

In a world constrained by climate change, the proper measure of the project's climate impact – of any project's impact – should not be based on assumptions inherent in a business as usual scenario that guarantees climate disaster. With respect to climate pollution, the national

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[281] *See*, http://www.bloomberg.com/news/2013-03-15/obama-will-use-nixon-era-law-to-fight-climate-change.html.

[282] The draft guidance can be found at: http://www.whitehouse.gov/sites/default/files/microsites/ceq/20100218-nepa-consideration-effects-ghg-draft-guidance.pdf

[283] The DSEIS indicates that the International Energy Agency World Energy Outlook 2012 projects 2030 Canadian tar sands production at slightly above 4 million bpd in the "current policy" scenario (DSEIS figure 1.4.7-1). According to the IEA, this scenario roughly corresponds to the "6DS" or "6 C" scenario, as in a 6 degree Celsius increase from pre-industrial global average temperature levels, http://www.iea.org/publications/scenariosandprojections/ - a pathway IEA Chief Economist Fatih Birol has characterized as having "catastrophic implications." IEA World Energy Outlook Press & Media Quotes. (1 December 2011, NTV MSNBC, Turkey). http://www.iea.org/publications/worldenergyoutlook/pressmedia/quotes/7/ The DSEIS assumes the tar sands production in 2030 is 4.3 – 5.2 million bpd (DSEIS Table 1.4-11), a level that is higher than the IEA's "current policy" scenario.

[284] The IEA refers to the "current policies" scenario as roughly equivalent to the IEA's 6 degree scenario (http://www.iea.org/publications/scenariosandprojections/); the projected increase in the "current scenarios" is 5.3 degrees Celsius. The Smith et al. "burning embers diagram" ends at a 5.6 degree Celsius increase. Smith et al. "Assessing dangerous climate change through an update of the Intergovernmental Panel on Climate Change (IPCC) 'reasons for concern'," PNAS (2009). http://www.pnas.org/content/106/11/4133.full The tar sands production projection, which is higher than in the IEA "current policies" scenario projection, is thus at the very top of, or off, the burning embers chart.

interest cannot be determined by considering only the incremental increase in emissions relative to an already-disastrous scenario.

The DSEIS briefly mentions an IEA scenario that is estimated to offer a 50 percent chance of staying below 2 degrees Celsius, and points out that while production from Canadian tar sands is greatly reduced relative to business as usual, even this scenario projects additional need for takeaway capacity. However, in this scenario, IEA relies heavily on assuming that "public concerns about the environmental impact…can be addressed" and that "growth in output is…made possible by the introduction of new [production] technologies which reduce emissions."[285] The IEA scenarios provide valuable information, but these assumptions in particular cannot be presupposed by the DSEIS.

[285] IEA WEO (2012), p. 104. http://www.worldenergyoutlook.org/publications/weo-2012/; IEA WEO (2010), pp.449-450. http://www.worldenergyoutlook.org/publications/weo-2010/.

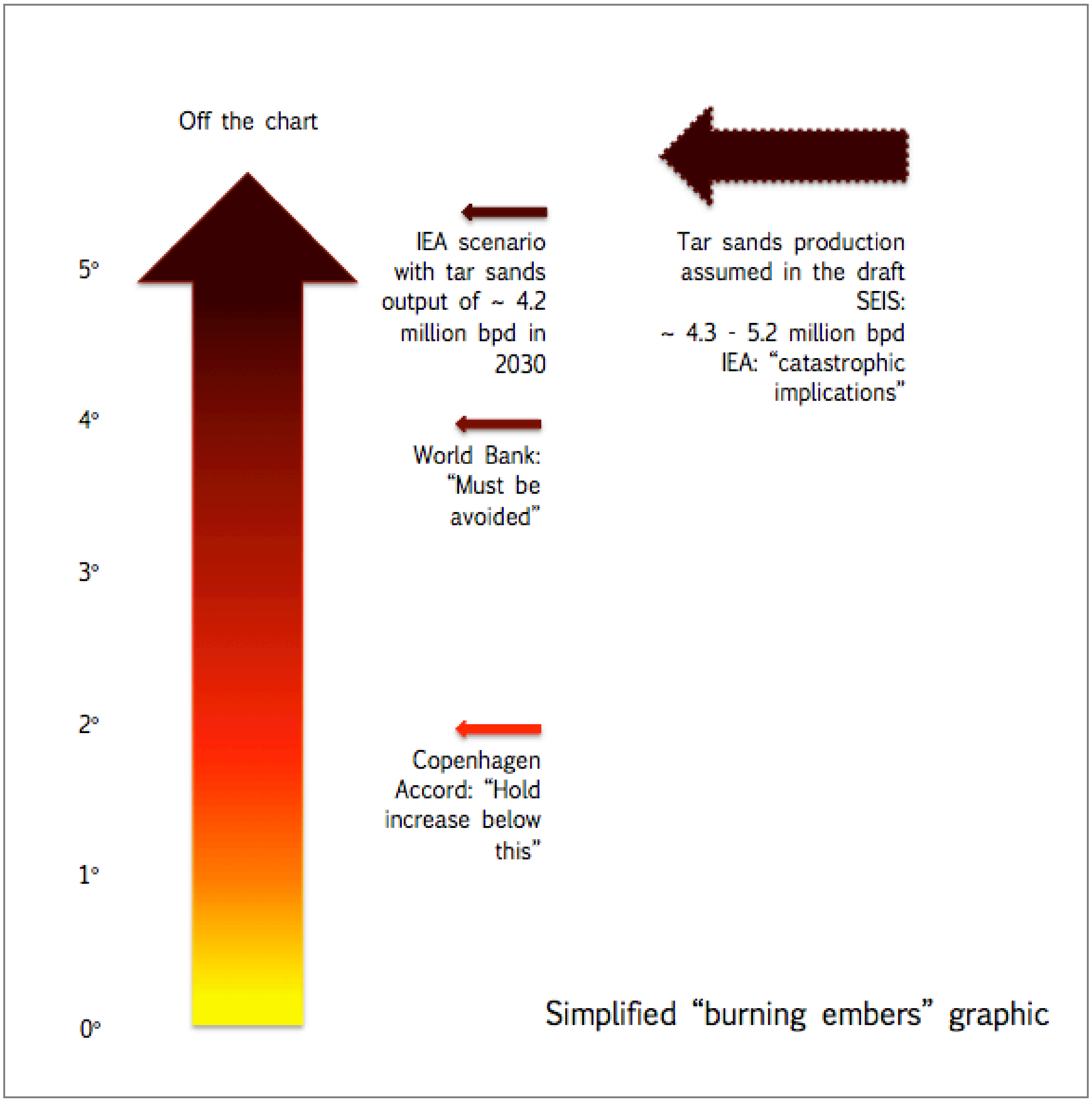

Figure 7. Simplified "burning embers" graphic.[286] Temperature increase in degrees Celsius above the pre-industrial.

The DSEIS further fails to consider a report by the MIT Joint Program on the Science and Policy of Global Change that finds little room for tar sands production, let alone expansion, with

[286] A simplified "burning embers" graphic made for the purpose of these comments, see note 7 above.

moderate climate policy.[287] In 2010, the MIT Joint Program noted that "the niche for the oil sands industry…mostly involves hoping climate policy will fail."[288]

The DSEIS also fails to assess tar sands projections in any scenarios that would give better than even odds of staying within the 2 degree limit.

Even the even-odds scenario is given short shrift, for unclear reasons. According to the IEA, "[n]o more than one-third of proven reserves of fossil fuels can be consumed prior to 2050 if the world is to achieve the 2 [degrees Celsius] goal".[289] Climate scientists warn that leaving four-fifths (80 percent) would be significantly safer.[290] But the DSEIS flatly notes, "industry will not [even] leave 55 percent of the World's proven reserves in the ground" (DSEIS Appendix W). Accepting the oil industry's self-serving outlook of the inevitability of future oil production is hardly a basis upon which to make sound policy to safeguard the climate and serve the interests of the American people.

Measured against the DSEIS's chosen (catastrophic) background, denying the project would reduce greenhouse gas emissions by 0.07 – 0.83 million metric tons CO2e per year, or 0.0002 – 0.003 percent of current global fossil fuel carbon dioxide emissions. (4.15-106). Meanwhile, the project's actual total carbon footprint is more than 181 million metric tons CO2e per year, or 0.7 percent of current global annual carbon dioxide emissions.[291] If the project were a country, it would place among the top 30 in carbon emissions.

i. President Obama's Leadership and Ambitious Federal Policy Dictate a More Searching Climate Change Assessment and Ultimately Denial of the Proposed Keystone XL Pipeline

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[287] Chan et al. "The Canadian Oil Sands Industry Under CO2 Constraints." Energy Policy (2012). http://globalchange.mit.edu/research/publications/2358; http://www.sciencedirect.com/science/article/pii/S0301421512006507 The MIT report does not identify their most stringent scenario as a 2C scenario and doesn't provide the cumulative emissions, but based on the area under the emissions graphs, the most stringent emissions path may offer roughly a 50% chance of staying below the 2C limit. In that case, tar sands production is phased out rapidly starting in 2010, falling to less than half by 2025.

[288] Chan et al. "Canada's Bitumen Industry Under CO2 Constraints." http://globalchange.mit.edu/research/publications/2021 MIT Joint Program on the Science and Policy of Global Change (2010).

[289] IEA, "World Energy Outlook Press & Media Quotes: 1 December 2011, NTV MSNBC, Turkey," http://www.iea.org/publications/worldenergyoutlook/pressmedia/quotes/7/

[290] Based on Meinshausen, et al. "Greenhouse-gas emission targets for limiting global warming to 2 degrees C." http://www.nature.com/nature/journal/v458/n724/full/nature08017.html Nature (2009). Reserves comparison: Carbon Tracker Initiative, 2012. "Unburnable Carbon: Are the world's financial markets carrying a carbon bubble?"

[291] Oil Change International "Cooking the Books, The True Climate Impact of Keystone XL." (2013). http://priceofoil.org/2013/04/16/cooking-the-books-the-true-climate-impact-of-keystone-xl/, attached as Exhibit 93.

The DSEIS's greenhouse gas assessment and analysis of climate change effects must take into account the President's leadership and the federal government's efforts to mitigate the effects of climate change and to reduce our nation's consumption of fossil fuels, and consider how the project fits in with those goals.

A commitment to climate leadership requires rigorous scrutiny of every executive action that will result in climate change impacts and taking every possible step to decrease the consumption of oil and especially high carbon heavy fuels, and to promote and incentivize meaningful investments in clean, alternative fuels.

In 2010, President Obama issued Executive Order 13514, calling for federal agencies and departments to lead by example in increasing sustainability and energy-efficiency across the federal government. These efforts include greenhouse gas reporting, 28% reductions in direct greenhouse gas emissions, and 13% reductions in indirect greenhouse gas emissions by 2020. Cumulatively, the President's reduction targets for federal government activities by 2020 are equivalent to reducing CO2 emissions by 101 million metric tons or reducing oil consumption by 235 million barrels.[292] Moreover, the President's recent issuance of ambitious standards for fuel economy and greenhouse gases, almost doubling fuel economy for cars, is a historic commitment to reducing oil dependence. These efforts will reduce oil consumption by 12 billion barrels.

The IEA is very clear about the impact of climate policy on U.S. oil demand. Meaningful climate policy would slash U.S. oil demand 50 percent by 2035 and 70 percent by 2050 based on a 2012 baseline. U.S. demand for oil has in fact declined since 2005 by 2.25 million barrels per day – or the equivalent of almost three Keystone XL pipelines.

The DSEIS acknowledges that the situation has changed since earlier assessments but asserts that although U.S. demand is dropping, this does not affect demand for refinery feedstock (1.4-1). However, the current level of global demand for petroleum products, which feeds the demand at the Gulf Coast refineries, is a market failure that we can only put off correcting for so long. We should have started making fossil fuels pay for much more of their external costs long ago. As the President has made clear, the time for delay is over. If we recognize this, it does not make sense to assert that denying the project will not accomplish much or anything with respect to tar sands production, because the tar sands producers will ship their product by other means, as if the time had not come for those other means, and their freight, to also pay for their external costs – pay for the damage fossil fuel production, transport, and use do to health, property, agriculture, ecosystem services, and more.

According to the Obama Administration, estimating the "social cost of carbon" is a "critical step in formulating policy responses to climate change."[293] The social cost of carbon is

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[292] http://www.whitehouse.gov/administration/eop/ceq/sustainability/fed-ghg.
[293] Economic Report of the President of the United States, March (2013). http://www.whitehouse.gov/sites/default/files/docs/erp2013/full_2013_economic_report_of_the_president.pdf

the monetized damage of some of the impacts of climate change on health, property, agriculture, ecosystem services, and more, resulting from adding one metric ton of CO_2 to the cumulative global sum of emissions.

In 2010, the Interagency Working Group on the Social Cost of Carbon (IAWG) estimated the social cost of carbon given a limited set of discount rates while emphasizing the incompleteness of these estimates.[294] The administration is currently reassessing these low estimates. They spanned from $6 to $73 per metric ton CO2, for 2015, and reached $16 to $136 per metric ton by 2050.

Based on the IAWG's estimates, the International Monetary Fund (IMF) in January 2013 used a social cost of carbon value of $25 per metric ton to estimate the current global fossil fuel subsidy arising from the failure to put a price on climate pollution.[295] This subsidy reinforces inequalities, encourages excessive energy consumption, reduces incentives for investments in renewable energy, and accelerates depletion of natural resources. Using that same value, the fossil fuel subsidy for the Keystone XL pipeline in its first year of operation would be over $4.5 billion.[296] The IAWG emphasized the importance of considering the full span of its estimates, not only one of the values. Using the full span, the annual social-cost-of-carbon price tag of the Keystone XL pipeline spans $1 - 13 billion in 2015. Using more recent estimates, the annual climate-damage-related social cost of the project could be an order of magnitude larger, and growing.[297] That's over 100 billion dollars per year. If society would have to subsidize the project to the tune of $100 billion, how can the project be in the national interest?

President Obama, in his 2013 State of the Union address, made a strong public commitment to combatting climate change: "[I]f Congress won't act soon to protect future generations, I will. I will direct my Cabinet to come up with executive actions we can take, now and in the future, to reduce pollution, prepare our communities for the consequences of climate change, and speed the transition to more sustainable sources of energy." Indeed, the President already has made commitments to reduce national carbon dioxide emissions by 17% from 2005 levels by 2020. And to avoid catastrophic climate disruption, the US must do its parts to ensure

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[294] Interagency Working Group on Social Cost of Carbon, United States Government, 2010. "Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866". http://www.whitehouse.gov/sites/default/files/omb/inforeg/for-agencies/Social-Cost-of-Carbon-for-RIA.pdf

[295] International Monetary Fund "Energy Subsidy Reform: Lessons and Implications." http://www.imf.org/external/np/pp/eng/2013/012813.pdf (2013).

[296] Multiplying the annual emissions of the Keystone XL pipeline by the relevant range of values in Table 4 in Interagency Working Group on Social Cost of Carbon, 2010.

[297] Laurie T. Johnson and Chris Hope "The social cost of carbon in U.S. regulatory impact analyses: an introduction and critique." http://link.springer.com/article/10.1007/s13412-012-0087-7 See also: http://www.jbs.cam.ac.uk/research/working_papers/2011/wp1109.pdf and http://www.economics-ejournal.org/economics/journalarticles/2012-10 (2012).

that atmospheric CO2 concentrations do not exceed 450 ppm. This means that the U.S. must take additional ambitious measures of reducing emissions by at least 80% by 2050.[298]

However, emissions reduction targets need to be understood in a cumulative emissions framework. Ultimately, what matters are not the emissions in a particular year or how they compare to those in another year, but the sum of emissions over a stretch of time. To take an extreme example, if we were to follow the off-the-charts business-as-usual scenario path for a period of time and then suffer catastrophic climate damage, emissions, along with productivity and well-being, might very well be quite low by 2050. Thus, emissions reduction levels and emission levels in a given target year do not provide the full context. The national conversation on climate change that the President called for in his first post-election speech last year needs to include an in-depth discussion of global cumulative emissions budgets from here to 2050, and shares thereof.

In 2012, the IEA estimated the then remaining global cumulative energy-related carbon budget until 2050 at less than 900 billion metric tons CO2, for even odds of staying below the 2 degree Celsius limit.[299] Seeking a safer 80 percent chance of staying below the limit, the remaining global 2014-2049 cumulative fossil fuel carbon budget is less than 420 billion metric tons CO2. [300] The project represents 1.5 percent of that cumulative budget.[301]

National interest decisions need to consider whether a project makes sense in a world that is actually seeking to minimize the dangers of climate change. Therefore, decision-makers must consider the total amount of carbon that will be released by the project into the atmosphere, in the context of global and national carbon budgets.

Unfortunately, the DSEIS demonstrates that the State Department has ignored the President's critical efforts to protect the American people from the catastrophic effects of climate

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[298] See http://climatecommunication.org/wp-content/uploads/2011/08/presidentialaction.pdf at 4.
[299] WEO (2012) p. 259.
[300] Derived from Meinshausen et al. (2009), as follows: The Meinshausen 2000-49 carbon budget for an 80 percent chance of staying below the 2 degree limit is 886 GtCO2. Unburnable Carbon (2012) estimates the corresponding 2010-49 budget by subtracting the 2000-09 CO2 emissions, to yield 565 GtCO2 (cf. Cooking the Books (2013)). Unburnable Carbon (2013) (Carbon Tracker "Unburnable Carbon 2013: Wasted Capital and Stranded Assets" (http://www.carbontracker.org/wastedcapital) estimates that 2000-12 fossil fuel CO2 emissions are 400 GtCO2 and assumes that land-use, land-use change, and forestry account for 7.3 percent of total CO2 emissions up to 2050. Using these assumptions regarding emissions, the 2013-49 fossil fuel CO2 budget is thus (886 – 400) x 0.927 = 451 GtCO2. (This is different from the estimate in Unburnable Carbon (2013) because we are starting from the Meinshausen (2009) Nature budget, not the Unburnable Carbon (2013) analysis itself, which is based on different assumptions.) Subtracting an estimated 33 GtCO2 for 2013, the 2014-49 fossil fuel carbon budget is 418 GtCO2.
[301] The project emissions are calculated in CO2e but the DSEIS notes that *in this context*, "emissions in units of CO2e are often nearly equal to the quantity of CO2 emitted" (DSEIS Appendix W). To be conservative, we assume project CO2 emissions are 95% of the 181 million tons of CO2e. (0.95*181 million * 36 years / 418 billion = 1.5 percent)

change. The State Department's failure to fully consider a clean fuels and energy conservation alternative, and the DSEIS's failure to analyze the incremental and cumulative effects of the proposed project and alternatives on climate change, and the failure to clarify the catastrophic climate context against which incremental emissions are considered cannot form the basis of a meaningful National Interest Determination.

3. <u>The DSEIS Fails to Adequate Consider the Frequency and Impact of Potential Releases</u>

The DSEIS provides data in Appendix K about failure rates of various pipeline components, but fails to use this data to provide an estimate of how frequently Keystone XL is likely to spill and what this could mean for communities along the pipeline route. Using data from the SEIS, statistical consultant David Malitz calculates that we would expect 19 spill incidents every ten years, or nearly two spill incidents per year from the proposed 875 mile pipeline with an average spillage of about 800 bbl annually. And, over a longer time span, that we would expect to see one "large" spill (1,000 bbl or more) approximately every 8 years, on average.[302] This is critical information that the DSEIS should be providing to assess the environmental impacts and national interest of the project.

a. The DSEIS Fails to Adequately Consider the Risk of Pipeline Failures Due to Corrosion

The DSEIS concludes that "no evidence is found that Alberta's pipeline contents are more corrosive than average crude oil" on the basis that corrosion rates in Alberta (accounting for 37.7 percent of incidents) are only slightly higher than those in the United States (34.4 percent of incidents).[303] However, this comparison does not account for either the greater age of the U.S. system or the fact that the shift towards large volumes of heavy crudes on the Alberta pipeline system has been relatively recent.

Over half of the pipelines currently operating in Alberta have been built in the last twenty years.[304] In contrast, the majority of hazardous liquid pipelines in the United States are more than forty-five years old.[305] The DSEIS fails to address why the U.S. pipeline system, which is more than twice the age of the Alberta pipeline system, has a smaller rate of corrosion incidents.

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[302] David Malitz, Ph.D. Calculation of Spill Risk for the Proposed Keystone XL Pipeline. Comment on the Draft Supplemental Environmental Impact Statement. March 27, 2013. Attached as Exhibit 94.
[303] DSEIS, at 4.13-14.
[304] Alberta's pipeline system increased from 49,597 km in 1990 (Alberta Energy and Utilities Board, Pipeline Performance in Alberta, 1990-2005, April 2007, p. 7, http://www.ercb.ca/docs/documents/reports/r2007-a.pdf (last accessed January 12, 2011)) to 105,555 km in 2010 (Visible Data, ERCB Database, January 7, 2011)
[305] Pipeline Safety Trust, Age of Liquid Pipelines, http://pstrust.org/initiatives_programs/transparency-of-pipelines/ageofliquidpipelines.htm (access 4/20/2013)

As the DSEIS acknowledges:

> "Pipeline systems older than 20 years have different cathodic protection specifications, different external protective coatings, if any, different SCADA systems, and different pipeline specifications. Pipeline systems greater than 40 years could have even less protection than 20 year old systems, not to mention those that would be installed today. Pipe specification coating, and cathodic protection are some factors that affect corrosion rates."[306]

Given the age of the U.S. pipeline system – and the differences in cathodic protection specifications, external protective coating, different SCADA systems, and different pipeline specifications – assumptions in the SDEIS would suggest that the U.S. system should see a significantly higher rate of corrosion related incidents that the newer Alberta system. The fact that the opposite is true suggests higher risks associated with products moved in the Alberta system. The DSEIS fails to evaluate the significance of the age difference between pipeline systems and in so doing, reaches an unsupported conclusion regarding the corrosion risk of WCSB crudes that contradicts its analysis elsewhere in the review.

Moreover, in addition to ignoring the age differences between the U.S. and Alberta pipeline systems, the DSEIS disregards the changing characteristics of the crudes produced in Alberta. From 2001 to 2012, heavy diluted bitumen production in Alberta more than tripled from 0.4 million bpd to 1.3 million bpd. While pipeline performance statistics are an important indication of risk, the relatively recent appearance of large volumes of diluted bitumen on the Alberta pipeline system suggests that its risks cannot be dismissed solely based on a comparison of historical pipeline incidence rates, as the DSEIS does.

The DSEIS does not consider the performance of pipeline systems in the U.S with the longest history of moving Canadian diluted bitumen tar sands. Diluted bitumen has only been moved on the U.S. pipeline system since the late 90s and federal regulators still don't provide data with the specificity to evaluate the safety record of pipelines moving tar sands. But a close look at pipeline incident data from states in the northern Midwest, which have seen the greatest volumes of tar sands diluted bitumen over the longest time period, is alarming. Pipelines in North Dakota, Minnesota, Wisconsin and Michigan spilled 3.6 times as much crude per mile than the national average between 20010 and 2012.[307]

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[306] DSEIS, at 4.13-16.

[307] North Dakota, Minnesota, Wisconsin, and Michigan have 6,416 miles of crude pipeline, or about 12.1 percent of the U.S. total. PHMSA. State Mileage by Commodity Statistics. 2013. primis.phmsa.dot.gov/comm/reports/safety/MI_detail1.html?nocache=8335#_OuterPanel_tab_4. Meanwhile, between 2007 and 2010 pipelines in North Dakota, Minnesota, Wisconsin, and Michigan spilled 27,911 barrels of crude in underground leaks, or 40.2% of the 63,987 barrels of crude spilled in the United States from 2010-12. Pipeline and Hazardouns Safety Materials Administration (PHMSA), Data and Statistics, Crude pipelines 2010-2012, http://www.phmsa.dot.gov/pipeline/library/data-stats.

The DSEIS mischaracterized the key findings of the California State Fire Marshal's (CSFM) Hazardous Liquid Pipeline Risk Assessment. As the DSEIS observes, because the pipelines serving southern California's Kern and Bakersfield oil fields provide the only case study for U.S. pipelines historically moving heavy viscous crudes with similarities to those being produced in Alberta. This study showed that pipelines operating in the range of 100°F to 159°F were between 8 and 23 times more likely to leak due to external corrosion and up to six times more likely to leak from any cause than pipelines operating under 100°F.[308] This is DSEIS indicated that Keystone XL will operate at a temperature range between 120°F and 150°F – a range that has been consistent with significantly higher rates of external corrosion in California.[309] However, the DSEIS failed to consider this information as it pertains to the potential impacts of the proposed Keystone XL pipeline through its project lifespan.

The DSEIS's rationale was based on the fact that many of the high temperature pipelines were older. State observed:

> "The California report states that pipelines operating at higher temperatures are also the oldest. The oldest pipelines in the dataset (50+ years old at the time of the study) tended to leak up to 20 times more frequently than the youngest pipelines (less than 10 years old at the time of the study). Although the data also showed that systems operating at 130 degrees Fahrenheit (°F) and higher had from 8 to 23 times higher leak rates than those operated at ambient temperature***, a direct cause-and-effect relationship between operating temperature and leak rate is not conclusive. The reported leak rate can be related to age, with the oldest pipelines having the higher leak rates… Therefore, a conclusion that higher leak rates would occur at higher temperatures cannot be drawn based on the California study alone."***[310] *(emphasis added)*

This statement is a mischaracterization of the findings of the CSFM study. The California study noted that the high temperature pipeline included a number of fairly old pipelines, which is why its authors did a logistic regression to determine whether pipeline age was masking temperature effects. They found that "while holding various factors constant, including pipe age, operating temperature was positively related to the probability of a leak occurring external corrosion." [311] In other words, after running statistical tests accounting for pipeline age, the California study did find a statistically significant correlation between pipeline temperature and external corrosion.

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[308] California State Fire Marshalls, Pipeline Risk Assessment, 1993. Pg. 68, http://osfm.fire.ca.gov/pipeline/pdf/publication/pipelineriskassessment.pdf.
[309] DSEIS, at 4.13-22.
[310] DSEIS, 4.13-15.
[311] CSFM, pgs. 68-72.

The reason for a correlation between pipeline temperature and external corrosion is well known. As the DSEIS acknowledges, the chemical reactions that cause external corrosion occur at faster rates at higher temperatures.[312]

Moreover, the DSEIS suggests that the proposed Keystone XL pipeline's fusion bonded epoxy (FBE) coating distinguish it from the pipelines in the California study. In fact, the CSFM study included pipelines with FBE coatings. These pipeline were also relatively new – with a 1984 mean year of pipeline construction, their average age was 3.4 years over the course of the 1981 to 1990 study. [313] However, despite their recent construction and FBE coatings, they still had a surprising rate of external corrosion and overall incident rates. [314] The study noted that pipelines with FBE operated at the highest average temperatures – at 115.6 F. [315] These temperatures are below those expected on the proposed Keystone XL pipeline.[316]

The DSEIS incorrectly discounts evidence of higher corrosion and/or pipeline failure rates associated with high temperature heavy crude pipelines, including the higher corrosion rate in the substantially newer Alberta pipeline system relative to the aging U.S. pipeline system, the higher pipeline spill rates in the northern Midwest, and the CSFM study showing a direct relationship between temperature and external corrosion (a relationship that holds after accounting for pipeline age). After discounting all available evidence that pipelines operating under the conditions proposed for Keystone XL have greater risks of failure, the DSEIS prematurely concludes "that the ultimate rate of corrosion may not be assessed at this time with the available data."[317]

The DSEIS does not adequately evaluate the impact that the crude products carried by Keystone XL and the conditions at which the pipeline will operate will have on the projects integrity and the environmental impacts of spills associated with a higher rate of external corrosion over the pipeline's operating lifetime.

b. The DSEIS Fails to Adequately Assess the Risk of Stress Corrosion Cracking on Keystone XL

The DSEIS fails to adequately assess the risk of stress corrosion cracking (SCC) on the proposed Keystone XL pipeline. The DSEIS prematurely dismisses the risk of SCC with the unsupported claim that "no stress corrosion cracking failures have been reported for pipelines with FBE coatings in over 40 years of experience."[318] This assessment ignores the fact that SCC is difficult to detect. The first instances of SCC in Canada where only observed in 1985, while

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[312] DSEIS, 4.13-15.
[313] CSFM, pg. 93.
[314] CSFM, pg. 93.
[315] CSFM, pg. 93.
[316] CSFM, pg. 93.
[317] DSEIS, at 4-13-16.
[318] *Id.* at 3.13-13.

subsequent investigation suggested SCC may have been involved in spills going back to the 1970s.[319] In a recent interview, the Association of Liquid Pipeline's CEO acknowledged "stress corrosion cracking is difficult to detect", noting that the "NTSB has encourage industry to improve the ability to detect these cracks."[320]

The DSEIS describes stress corrosion cracking as a phenomena caused by the combine action of corrosion and applied stress.[321] While it note that pipeline expansion and contraction can occur in response to temperature changes, it does not evaluate the risks of this cyclic stress for Keystone XL, which has an operating temperature range significantly greater than pipelines moving lighter, less viscous crudes. Moreover, the DSEIS fails to consider the cyclic stress associated with pressure differentials across the Keystone XL pipeline, which exceed 1,100 pounds per square inch at pump station outlet points followed by a relatively rapid pressure drop to 50 pounds per square inch.[322]

c. The DSEIS Assessment of Spill Magnitudes for Project Is Flawed

The DSEIS's assessment of likely spill magnitudes for the Keystone XL pipeline is flawed. It extrapolates likely spill magnitudes on the project from Pipeline and Hazardous Safety Materials Administration's (PHMSA) incident database.[323] However, the majority of the U.S. hazardous liquid pipeline system is comprised of significantly smaller, lower capacity pipelines than the proposed Keystone XL. The importance of this distinction is clear when considering the project's SCADA leak detection system, which is only capable of detecting leaks in real time that are between 1.5 percent to 2 percent of the pipeline flow rate.[324] For an 830,000 barrel per day pipeline, this means that spills smaller than 12,450 barrels per day, or 522,900 gallons per day, will be unlikely to be detected in real time.

The DSEIS does not consider the performance thresholds of Keystone XL's computer-based, non-real time accumulated gain/loss volume trending leak detection systems and their impact on potential spill magnitudes. While the DSEIS observes that the non-real time leak detection "would be used to assist in identifying low rate or seepage releases below the 1.5 percent to 2 percent by volume detection threshold", it does not consider the time frame for the detection of a variety of leaks below that threshold assess spill magnitude scenarios accordingly.

Because Keystone XL is in both the United States and Canada, it will be obligated to comply with minimum safety standards of both countries. While the PHMSA regulations do not provide performance metrics for non-real time leak detection systems, Canadian pipeline are

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[319] National Energy Board Report of the Inquiry MH-2-95, Public Inquiry Concerning Stress Corrosion Cracking on Canadian Oil and Gas Pipelines, National Energy Board Canada, 1996, 7.
[320] Andrew Black, E&E News Interview, July 19, 2012, http://www.eenews.net/tv/transcript/1560.
[321] DSEIS, at 3.13-13.
[322] *Id.* at 3.13-12.
[323] *Id.* at 3.13-23.
[324] *Id.* at 3.13-24.

obligated to abide by CSA Z662 Appendix E. Keystone XL will be doubly obligated to comply with CSA Z662-11 as it is required both by regulation and by Special Condition 31. This standard requires non-real time leak detection systems to identify leaks greater than 2% within one week and leaks greater than 1% within a month. For a pipeline with Keystone XL's capacity, this translated to finding a spill of up to 116,200 barrels, or 4.9 million gallons, within a week. A one percent capacity leak could spill as much as 257,300 barrels, or 10.8 million gallons, before detection was required by Canadian regulations.

The DSEIS incorrectly extrapolates form U.S. spill data to assess the potential magnitude of spills from the project by using statistics from the entire U.S. hazardous liquid pipeline system. The U.S. hazardous liquid pipeline system is composed of pipelines that have significantly smaller average diameters and capacities than Keystone XL. The DSEIS notes that spills greater than 1,000 barrels are relatively rare of the U.S. hazardous pipeline system (comprising about 4 percent of pipeline accidents) and are generally association "with severe damage to or complete failure of a major pipeline component or monitoring system."[325]

This may be the case with small pipelines, but it is not the case with larger pipelines. This fact is recognized by a footnote in the DSEIS, which notes that for crude oil spills from pipelines 16-inch diameter and larger, large spills comprise 26 percent of incidents, compared to the 4 percent for the entire U.S. pipeline system.[326] For Keystone XL - a 36 inch diameter, 830,000 bpd pipeline – even these statistics likely significantly understate the proportion of the pipelines leaks which will ultimately prove to be very large.

The DSEIS does not adequately address the spill frequency or magnitude likely on the proposed Keystone XL pipeline over its operational history. Without an adequate evaluation of spill frequencies and magnitudes, it is not possible to adequately consider the impacts of potential spills on the project.

d. The DSEIS failed to consider TransCanada's operating history

The DSEIS failed to consider TransCanada's operating history and its impact on the potential environmental impacts of the Keystone XL pipeline. In many areas, the DSEIS assumes many of the risks associated with the project will be mitigated by the operator's construction, operation, pipeline integrity and spill response practices. However, the company's operating history is an important factor in the considering the risk and environmental impact of tar sands crude releases.

TransCanada has built two pipelines in the United States in recent years – the Keystone I pipeline and the Bison natural gas pipeline. Both of these pipelines operated under a series of

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[325] *Id.* at 3.13-23.
[326] *Id.* at 4.13-17, footnote 14.

special safety conditions and were described as state-of-the-art pipeline which would “meet or exceed world class safety and environmental standards.”[327]

The first Keystone pipeline (Keystone I) from Hardesty, Alberta to Wood River, Illinois and Cushing, Oklahoma was TransCanada’s first wholly owned and operated crude oil pipeline. In its environmental risk assessment for Keystone I, TransCanada forecast that Keystone I would leak no more than 1.4 times a decade and noted that it had agreed to 51 special conditions that would increase its safety.[328]

However, the Keystone I pipeline leaked 14 times in the United State – including one spill of as much as 21,000 gallons – and 21 times in Canada during its first year of operation.[329] Regulators at the Pipeline and Hazardous Materials Safety Administration (PHMSA) had to intervene, issuing a Corrective Action Order (CAO) temporarily shutting the pipeline down as an imminent threat to life, safety and the environment. This made Keystone I the newest pipeline in U.S. history to receive such an order.[330]

Bison natural gas pipeline is the second major pipeline constructed by TransCanada in the United States in recent years. TransCanada touted the extra safety measures it was taking for its “state-of-the-art” Bison natural gas pipeline, noting that it had agreed to special conditions, and claiming that the pipeline “will be in place for 20 or 30 years before they need any repairs.”[331] Two months after TransCanada avowed the safety of its Bison pipeline, a sixty foot section of the pipeline exploded.[332]

e. The DSEIS Fails to Consider TransCanada’s Organizational Safety Culture and Potential Impacts Associated with It

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[327] TransCanada, Keystone Pipeline Starts Deliveries to U.S. Midwest, June 30, 2010, http://www.transcanada.com/5407.html.

[328] State Department, Keystone I Final EIS, Appendix L: Pipeline Risk Assessment, June 2006, http://www.cardnoentrix.com/keystone/project/eis/Appendix%20L_Pipeline%20Risk%20Assessment.pdf

[329] State Department, Keystone XL FEIS, August 2011, 3.13-12-14; Mike De Souza, Feds recorded 100 pipeline spills and accidents in the last two years, Vancouver Sun, July 5, 2011, http://www.canada.com/business/Feds+recorded+pipeline+spills+accidents+last+years/5053005/story.html#ixzz2R64CUaXR.

[330] Pipeline and Hazardous Safety Materials Administration, Corrective Action Order, June 3, 2011, http://blog.nwf.org/wildlifepromise/files/2011/06/320115006H_CAO_06032011.pdf; Anthony Swift, The Keystone tar sands pipeline becomes the newest hazardous liquid pipeline to be deemed an immediate threat to public safety by regulators, June 6, 2011, http://switchboard.nrdc.org/blogs/aswift/the_keystone_tar_sands_pipelin.html.

[331] Richard Nemec, TransCanada’s Newest U.S. Asset: Bison Pipeline, Pipeline and Gas Journal, May 2011, http://www.pipelineandgasjournal.com/transcanada%E2%80%99s-newest-us-asset-bison-pipeline?page=show.

[332] Jeremy Fugleberg, TransCanada's new Bison gas pipeline blows out in Wyoming, Journal Star, July 25, 2011, http://journalstar.com/business/local/article_e284b5e7-8647-53dc-bcb0-53a7f035e3e4.html.

The DSEIS fails to consider TransCanada's culture of safety or evaluate the role that organizational safety failures will have on the frequency, magnitude and impact of releases from the project. In its investigation of the 2010 Marshal, Michigan tar sands spill, the National Transportation Safety Board ("NTSB") determined that the spill was causes by "pervasive organizational failures by a pipeline operator along with weak federal regulations."[333] The NTSB investigation showed in detail how failures in Enbridge's culture of safety and weak federal oversight at the Pipeline and Hazardous Materials Administration (PHMSA) led to the accident and exacerbated its environmental impact.[334] Defects in organizational safety culture have recently been recognized by both the NEB and the OECD as significant factors in the environmental risks of oil and gas pipeline projects.[335] The DSEIS should consider TransCanada's organizational safety culture as it relates to the potential environmental impacts of the proposed Keystone XL pipeline.

TransCanada's compliance with safety standards has been the subject of significant public scrutiny following the failures on Keystone I, the Bison pipeline, accounts of several whistleblowers, and the launch of an audit on the company's construction, inspection and integrity management practices.[336]

Evan Vokes, a TransCanada metallurgical engineer sent to sort out the problems with the Bison project, found examples of shoddy welding and poorly trained inspectors who were not identifying all of the welding problems.[337] In response to his concerns, his supervisors sent him what he described as "increasingly pressured emails about how things were OK to do it that way."[338]

Mr. Vokes provided documents to TransCanada senior executives that documented systemic failure to follow code and regulations in 2011.[339] However, in the face of inaction by management and after determining that TransCanada was consistently placing budget and

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[333] National Transportation Safety Board, Enbridge Incorporated Hazardous Liquid Pipeline Rupture and Release, July 10, 2012, http://www.ntsb.gov/news/events/2012/marshall_mi/index.html.
[334] *Id*.
[335] OECD, Corporate Governance for Process Safety: Draft Guidance for Senior Leaders in High Hazard Industries, March 2012.
[336] National Energy Board, Letter to Russ Girling, October 11, 2012, http://www.neb-one.gc.ca/clf-nsi/rsftyndthnvrnmnt/sfty/brdrdr/trnscnd2012_10-11-eng.pdf; National Energy Board, Letter to Russ Girling, October 30, 2012, http://www.neb-one.gc.ca/clf-nsi/rsftyndthnvrnmnt/sfty/brdrdr/trnscnd2012_10-30-eng.pdf.
[337] CBC, Quality concerns arose before TransCanada pipeline blast, Oct. 24, 2012, http://www.cbc.ca/news/canada/story/2012/10/24/transcanada-pipelines-bison-explosion.html.
[338] Nathan VanderKlippe, Energy board launches TransCanada audit, The Globe and Mail, Oct. 31, 2012, http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/energy-board-launches-transcanada-audit/article4801594/.
[339] Andrew Nikiforuk, Pipeline Whistleblower: Cracks in The System, The Tyee, Oct. 1, 2012, http://thetyee.ca/News/2012/10/01/Cracks-In-Pipeline-System/.

schedule considerations ahead of quality, he raised his concerns with Canadian pipeline regulators at the NEB.[340]

After a preliminary investigation corroborated many of Mr. Vokes' claims, investigators launched a sweeping audit of TransCanada's operations.[341] NEB regulators cited concern with TransCanada's non-compliance with NEB regulations and what may be an erosion of the safety culture at the company.[342] In a letter announcing the audit, regulators at the NEB observed:

> "The Board is concerned by TransCanada's non-compliance with NEB regulations, as well as its own internal management systems and procedures."[343]

On August 17th, 2012, the NEB found that TransCanada was not in compliance with minimum safety standards requiring that safety valves have secondary power sources.[344]

U.S. regulators with PHMSA inspecting the Bison project took issue with the quality-assurance of inspections, the qualifications of people working on the pipeline and the procedures used to test the coating on the pipe.[345]

Another whistleblower in the United States, Michael Klink, worked as a quality control inspector during the construction of the Keystone I pipeline. In an opinion editorial article submitted to the Lincoln Journal Star, he stated:

> "As an inspector, my job was to monitor the construction of the first Keystone pipeline. I oversaw construction at the pump stations that have been such a problem on that line, which has already spilled more than a dozen times. I am coming forward because my kids encouraged me to tell the truth about what was done and covered up.

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[340] Andrew Nikiforuk, Pipeline Whistleblower: Cracks in The System, The Tyee, Oct. 1, 2012, http://thetyee.ca/News/2012/10/01/Cracks-In-Pipeline-System/.
[341] National Energy Board, Letter to Mr. King, VP Engineering TransCanada, Oct. 11, 2012, http://www.neb-one.gc.ca/clf-nsi/rsftyndthnvrnmnt/sfty/brdrdr/trnscnd2012_10-11-eng.html.
[342] CBC, Regulator probing 'safety culture' at TransCanada Pipelines, Oct. 17, 2012, http://www.cbc.ca/news/canada/story/2012/10/16/transcanada-pipelines-whistleblower.html; CBC, Regulator probing 'safety culture' at TransCanada Pipelines: Investigation follows revelations from whistleblower, Oct. 17, 2012, http://www.cbc.ca/news/canada/story/2012/10/16/transcanada-pipelines-whistleblower.html.
[343] National Energy Board, Letter to Mr. King, VP Engineering TransCanada, Oct. 11, 2012, http://www.neb-one.gc.ca/clf-nsi/rsftyndthnvrnmnt/sfty/brdrdr/trnscnd2012_10-11-eng.html.
[344] National Energy Board, Letter to Mr. Russell, TransCanada, Aug. 17, 2012, http://www.neb-one.gc.ca/clf-nsi/rsftyndthnvrnmnt/sfty/brdrdr/so_t241_002_2012-eng.html.
[345] CBC, Quality concerns arose before TransCanada pipeline blast, Oct. 24, 2012, http://www.cbc.ca/news/canada/story/2012/10/24/transcanada-pipelines-bison-explosion.html.

> When I last raised concerns about corners being cut, I lost my job — but people along the Keystone XL pathway have a lot more to lose if this project moves forward with the same shoddy work.
>
> What did I see? Cheap foreign steel that cracked when workers tried to weld it, foundations for pump stations that you would never consider using in your own home, fudged safety tests, Bechtel staffers explaining away leaks during pressure tests as "not too bad," shortcuts on the steel and rebar that are essential for safe pipeline operation and siting of facilities on completely inappropriate spots like wetlands.
>
> I shared these concerns with my bosses, who communicated them to the bigwigs at TransCanada, but nothing changed. TransCanada didn't appear to care." [346]

According to the CBC, TransCanada has publicly admitted that it hasn't always followed an NEB regulation that ensures contractors can't pressure inspectors to sign off on work that is not up to code.[347] CBC also noted that TransCanada claimed noncompliance with that regulation is industry standard.[348]

The DSEIS should consider TransCanada's organizational safety culture and regulatory compliance history in its evaluation of the environmental impacts of Keystone XL. As the NTSB's investigation of the Marshall oil spill and other pipeline accidents demonstrates, large pipeline releases are often caused or abetted by regulatory non-compliance by the operator at the pipeline construction, operation, integrity management or spill preparation and response stages. As such, TransCanada's organizational culture of safety and history are an important consideration when evaluate the environmental impacts of the Keystone XL pipeline.

4. <u>The DSEIS Fails to Adequately Analyze TransCanada's Oil Pollution Act Facility Response Plan</u>

a. The Importance of Crude Oil Spill Response Analysis to the DSEIS Process

By far, the environmental risk that generates the most concern in the communities that would be impacted by KXL, and that has the highest profile with the general public, is the risk

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[346] Journal Star, Mike Klink: Keystone XL pipeline not safe, Dec. 31, 2011, http://journalstar.com/news/opinion/editorial/columnists/mike-klink-keystone-xl-pipeline-not-safe/article_4b713d36-42fc-5065-a370-f7b371cb1ece.html.

[347] CBC, Regulator probing 'safety culture' at TransCanada Pipelines: Investigation follows revelations from whistleblower, Oct. 17, 2012, http://www.cbc.ca/news/canada/story/2012/10/16/transcanada-pipelines-whistleblower.html.

[348] CBC, Regulator probing 'safety culture' at TransCanada Pipelines: Investigation follows revelations from whistleblower, Oct. 17, 2012, http://www.cbc.ca/news/canada/story/2012/10/16/transcanada-pipelines-whistleblower.html.

that TransCanada will spill millions of gallons of heavy diluted bitumen and then fail to respond quickly and thoroughly. This concern is founded on a long history of disastrous oil spills punctuated by a number of recent spills caused by oil company failures, including:

- BP's Deepwater Horizon explosion in the Gulf of Mexico;
- Enbridge's Line 6b rupture into the Kalamazoo River;
- Exxon's Silvertip Pipeline rupture into the Yellowstone River; and
- Exxon's Pegasus Pipeline rupture into the town of Mayflower, Arkansas.

When these spills are viewed against the drumbeat of life-taking natural gas pipeline explosions, Canadian tar sands industry spills, and frequent smaller U.S. pipeline ruptures, Americans have good cause to fear pipeline oil spills and demand that the Administration aggressively ensure that pipeline companies are able to respond to spills quickly and aggressively.

Given these recent spills and their substantial impacts, the DSEIS's abysmal analysis of TransCanada's oil spill response capacity is surprising and alarming. The public expects hard evidence of TransCanada's actual capacity to protect their families, homes, and communities from a KXL rupture. Rather than provide such evidence, the Administration relies on dry statistics about the frequency of spills, TransCanada's unsubstantiated claims about its spill response capability, and vague recommendations for improved agency oversight, all buried in a tidal wave of generic oil spill information that that says nothing about TransCanada's actual plans or capacity.

The DSEIS does not include or analyze TransCanada's federally required KXL oil spill response plan, and it also does not provide complete lists of on-the-ground spill response equipment and personnel along the KXL route. Instead, this information remains buried in TransCanada's files and the files of its spill response contractors. This failure means that the DSEIS provides no assurance that TransCanada can respond quickly and thoroughly to a worst-case rupture of its pipeline. It also means that the DSEIS cannot and has not considered alternative ways to improve TransCanada's planning or made any meaningful recommendations for improvements. Finally, this failure means that the DSEIS fails to provide information on which meaningful public spill response comments can be based. As such, the DSEIS fails to comply with NEPA, and it also fails the American people.

b. The DSEIS Must Include an Analysis of the KXL FRP to the Full Extent Required by NEPA

The DSEIS's discussion of spill response planning is included as part of Section 4.13.5, entitled "Recommended Additional Mitigation." Pipeline spill response planning is not "recommended additional mitigation." Instead, the Oil Pollution Act, 33 U.S.C. § 1321 ("Oil Pollution Act" or "OPA"), mandates that TransCanada prepare and submit a facility response plan ("FRP") to the Pipeline and Hazardous Materials Safety Administration ("PHMSA").[349] PHMSA is required by law to fully review and determine whether or not TransCanada's FRP is in compliance with the OPA[350] A failure by PHMSA to ensure that TransCanada has complied with federal law could result in a botched worst case oil spill response with disastrous environmental and financial impacts and consequences. As such, PHMSA's review of TransCanada's FRP is a major federal action subject to NEPA. To comply with NEPA, the DSEIS must fully analyze the FRP's impacts and unavoidable consequences and also consider alternatives to TransCanada's preferred plan. Because it treats the Oil Pollution Act's requirements as mere "recommended additional mitigation," rather than mandatory major federal action, the DSEIS fails to analyze the FRP to the extent required by NEPA and is legally deficient.

The DSEIS presents a confusing and unclear description of federal oil spill response planning statutory requirements that protect the public from potential KXL spills, and as a result fails to correctly analyze these actions as required by NEPA. Specifically, the DSEIS:

- Fails to distinguish the various "federal actions" that the federal government must take to regulate KXL oil spill planning;
- Fails to correctly analyze the procedural requirements and timing for these federal actions and thereby improperly excludes required analysis;
- Fails to analyze TransCanada's FRP as required by NEPA;
- Misleads citizens about the functioning of U.S. oil spill law; and
- Fails to provide project-specific information within the DSEIS upon which meaningful comments could be based.

Citizens want details about TransCanada's actual spill response plans for KXL, but the DSEIS provides only general descriptions of TransCanada's plans <u>for its existing pipelines</u> and generic "oil spill 101" information, neither of which include information specifically about KXL. In fact, the DSEIS repeatedly admits that it does not contain key project-specific information. Its rationale for omitting this information depends on a fundamentally flaw understanding of the FRP approval process and the integration of NEPA into this process. As a consequence, the DSEIS does not include any analysis of TransCanada's KXL OPA FRP.

For the sake of clarity, the DSEIS should contain a clear discussion that distinguishes the following three statutory provisions that regulate TransCanada's oil spill planning:

Oil Pollution Act "facility response plan" – The OPA is the federal government's primary law related to oil spill response and cleanup. It requires pipeline owners and operators to submit "facility response plans" for containment and cleanup of oil after a pipeline has ruptured.[351]

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[349] 33 U.S.C. § 1321(j)(5).
[350] 33 U.S.C. § 1321(j)(5)(E). PHMSA is required to formally determine whether it should "approve" the KXL OPA FRP or not.
[351] 33 U.S.C. § 1321(j)(5).

PHMSA's oil spill response regulations are contained in 49 C.F.R. Part 194 ("Part 194"), which was promulgated pursuant to the OPA and no other statutory authority.[352] Part 194 includes detailed requirements and guidelines for FRPs, and PHMSA is required by the OPA to "approve" FRPs that comply with federal law or reject those that do not. The DSEIS refers to the OPA FRP as a "Pipeline Spill Response Plan,"[353] which is a descriptive phrase used in PHMSA regulations but is not the name given to this plan by the OPA. Use of a term other than that used in the statute is confusing because it fails to clearly indicate the statutory authority for this plan. For clarity, these comments use the statutory term "Facility Response Plan" or "FRP" when referring to TransCanada's OPA spill response plan.

Pipeline Safety Act "emergency response plan" – The Pipeline Safety Act, 49 U.S.C. § 60101 *et seq*. ("PSA"), requires the following:

> Facility Operation Information Standards.--The Secretary shall prescribe minimum standards requiring an operator of a pipeline facility subject to this chapter to <u>maintain</u>, to the extent practicable, <u>information</u> related to operating the facility as required by the standards prescribed under this chapter and, when requested, to <u>make the information available</u> to the Secretary and an appropriate State official as determined by the Secretary. The information shall include –
>
> * * *
>
> (5) <u>an</u> emergency response plan describing the operator's procedures for responding to and containing releases, including--
> (A) identifying specific action the operator will take on discovering a release;
> (B) liaison procedures with State and local authorities for emergency response; and
> (C) communication and alert procedures for immediately notifying State and local officials at the time of a release . . . . [354]

This is the only provision in the PSA that references an emergency response plan. Moreover, the PSA contains no detailed standards or procedures related to spill response planning. To put this provision into context, it is important to note that 49 U.S.C. § 60102(d) is entitled, "Facility operation information standards," such that the subsection's primary objective is insuring that PHMSA has access to pipeline operator information. The plain language of this section does not require that PHMSA approve emergency response plans; it only requires that operators "maintain . . . and make information available" including "an emergency response

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[352] 58 FR 14523 (Mar. 18, 1993), as confirmed by 70 Fed. Reg. 8734 (Feb. 23, 2005). PHMSA's rulemaking for Part 194 does not list the PSA, 49 U.S.C. § 60102, as statutory authority and does not consider PSA requirements.
[353] DSEIS, at 4.13.75.
[354] 49 U.S.C. § 60102(d)(5) (emphasis added)

plan." Also, the language does not refer to a specific response plan required by any law or regulation, only that pipeline operators have "an emergency response plan." Thus, the PSA does not require that TransCanada prepare any specific response plan, only that it include one as part of its operations manual. Since the PSA contains no detailed requirements for spill response planning and does not require that PHMSA approve a spill response plan, PHMSA in fact does not approve any spill response plan pursuant to the PSA.

PHMSA's implementing regulations for 49 U.S.C. § 60102(d) are contained in 49 C.F.R. Part 195 ("Part 195"). Since the PSA requires only that TransCanada provide access to a spill response plan, Part 195 also contains no emergency response planning standards and does not even use the term "emergency response plan." Instead, Part 195 requires only that emergency "provisions" be included in a pipeline operator's operations manual.[355] The only language in Part 195 that even touches on removal of spilled material is the following:

> (e) Emergencies. The manual required by paragraph (a) of this section must include procedures for the following to provide safety when an emergency condition occurs:
>
> * * *
>
> (2) Prompt and effective response to a notice of each type emergency, including fire or explosion occurring near or directly involving a pipeline facility, accidental release of hazardous liquid or carbon dioxide from a pipeline facility, operational failure causing a hazardous condition, and natural disaster affecting pipeline facilities.
> (3) Having personnel, equipment, instruments, tools, and material available as needed at the scene of an emergency.
> (4) Taking necessary action, such as emergency shutdown or pressure reduction, to minimize the volume of hazardous liquid or carbon dioxide that is released from any section of a pipeline system in the event of a failure.
> (5) Control of released hazardous liquid or carbon dioxide at an accident scene to minimize the hazards, including possible intentional ignition in the cases of flammable highly volatile liquid.[356]

Thus, PHMSA's PSA regulations contain no standards for oil spill response planning and no requirement that PHMSA approve emergency response plans, but merely require that TransCanada's operations manual contain general safety provisions. As this regulation is applicable to all hazardous liquids pipelines, and not just petroleum pipelines, Part 195 does not include standards that specifically address the containment or removal of spilled petroleum.

[355] 49 C.F.R. § 195.402(a), (e).
[356] 49 C.F.R. § 195.402(e).

Since the PSA and Part 195 do not contain standards for removal of spilled crude oil and do not require that PHMSA approve an oil spill response plan, the PSA does not mandate the preparation of a distinct oil spill response plan. Instead, it requires only that operators provide access to a plan. In contrast, the OPA and its implementing regulations include standards for and require approval of FRPs, which are then used by pipeline operators to fulfill the PSA's information requirements. Thus, the DSEIS's assertion that TransCanada is required by law to prepare two different oil spill response plans is false.

Clean Water Act "Spill Prevention, Control, and Countermeasure Plan ("SPCC Plan") – Section 311 of the Clean Water Act ("CWA") regulates oil spills <u>only</u> during construction and mitigation activities, such as spills of diesel fuel from heavy equipment. It does not include any standards for containment or cleanup of crude oil spilled as a result of a pipeline leak or rupture. The U.S.E.P.A. approves SPCC Plans.

Thus, the SPCC Plan, PSA "emergency response plan" information requirement, and the OPA FRP are distinct mandates directed at different purposes. The SPCC Plan applies only during construction, the PSA "emergency response plan" requirement is an information requirement, and the OPA mandates the preparation and approval of an oil spill containment and cleanup plan for spills during pipeline operations. The DSEIS should not confuse the purposes of and actions required by these statutory requirements.

Yet, the DSEIS and TransCanada intentionally obfuscate federal law by stating that the "emergency response plan" required by the PSA for crude oil pipelines is separate from the FRP required by the OPA. There are a number of reasons why there cannot be two separate plans. First, as noted, the PSA and its implementing regulations do not contain standards for or require approval of an oil spill response plan. Second, the limited and very broad "emergency response plan" descriptions in the PSA and the very broad "emergency" planning requirements in Part 195 are entirely subsumed by the far more detailed oil spill response planning requirements in the OPA and Part 194. Since more detailed statutory requirements take precedence over general requirements, the FRP acts as the "emergency response plan" for the purposes of the PSA. Third, PHMSA did not cite the PSA as statutory authority for its oil spill response planning regulations in Part 194, but rather cited only the OPA.[357] This is evidence that PHMSA itself considers the OPA to be the <u>only</u> source of its oil spill response planning duties. Fourth, the existence of two separate and distinct oil spill response plans would be redundant and create a risk of confusion during implementation, and therefore is bad public policy. Thus, the primary source of authority for pipeline oil spill response plans is the OPA, not the PSA.

The DSEIS states: "[t]he PSRP would not necessarily need to be a separate report from the ERP."[358] In fact, the "PSRP" (OPA FRP) is the "emergency response plan" that pipeline

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[357] PHMSA rulemakings for Part 195 do not identify the OPA as statutory authority. *E.g.*, 61 F.R. 18512, 18518 (Apr. 26, 1996).
[358] DSEIS, at 4.13-75.

operators maintain and make available to PHMSA. Since only one spill response plan is required by federal law, this statement is incorrect.

The DSEIS should not confuse citizens by stating that there are two oil spill response plans when there are not. As a consequence, any document prepared by TransCanada claiming to be an oil spill response plan apart from the OPA FRP is merely a self-constructed creation with no legal authority and cannot be the basis for NEPA review of TransCanada's OPA FRP.

i. PHMSA's review of TransCanada's KXL FRP is a major federal action subject to NEPA

The OPA requires TransCanada to "prepare and submit to the President a plan for responding, to the maximum extent practicable, to a worst case discharge, and to a substantial threat of such a discharge, of oil or a hazardous substance."[359] In response to a pipeline company's submission, the law requires that:

> the President[360] shall –
> (i) promptly review such response plan;
> (ii) require amendments to any plan that does not meet the requirements of this paragraph;
> (iii) approve any plan that meets the requirements of this paragraph;
> (iv) review each plan periodically thereafter; . . . .[361]

The President's approval of new FRPs under 33 U.S.C. § 1321(j)(5) and his approval of significant changes to existing FRPs are "major Federal actions significantly affecting the quality of the human environment" as this term is defined by CEQ regulations.[362] Moreover, the federal

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[359] 33 U.S.C. § 1321(j)(5)(A)(i)
[360] The President has delegated his individual responsibility to approve plans to the Secretary of the U.S. Department of Transportation, who has in turn delegated this responsibility to the Pipeline and Hazardous Materials Safety Administration ("PHMSA"). Executive Order 12777 (October 18, 1991). The DOT implemented the OPA spill response planning requirement by promulgating 49 C.F.R. Chapter 194.
[361] 33U.S.C. § 1321(j)(5)(E).
[362] CEQ regulations define major federal actions to include, "Approval of specific projects, such as construction or management activities located in a defined geographic area. Projects include actions approved by permit or other regulatory decision . . . ." 40 C.F.R. § 1508.18(b)(4). Since the OPA expressly requires "approval" of FRPs, which approval is clearly a "regulatory decision," PHMSA's approval of TransCanada's FRP is a federal action for the purposes of NEPA. Such action is "major" because the effectiveness, or lack thereof, of TransCanada's FRP would "significantly" impact the environment for better or worse in the event of a major spill. Further, such spill could have substantial, controversial, and uncertain impacts on public health and safety, unique geographic areas, significant scientific, cultural, and historical sites, and threatened and endangered species. Moreover, submission of a legally defective FRP by TransCanada and approval of such FRP would violate the OPA, which was passed to protect the environment.

courts have expressly found that approval of an FRP is subject to NEPA.[363] Therefore, PHMSA's approval of an FRP for KXL is a major federal action. In fact, this approval is one of the most significant federal actions that triggered the preparation of the FEIS and DSEIS.[364] As such, NEPA requires that the DSEIS analyze: (1) the impact of the proposed FRP on the environment; (2) the unavoidable environmental effects should the proposed FRP be approved; and (3) alternatives to the proposed FRP.[365]

NEPA requires that each agency consider the impacts of and alternatives to its particular actions. Where an EIS is used to inform the decisions of multiple agencies, the joint EIS must consider the impacts of and alternatives to each agency's particular action or actions. An EIS that fails to inform an agency about the impacts and alternatives to its particular actions would not accomplish the purposes of NEPA. For example, the DSEIS must inform the U.S.A.C.E. about KXL's impacts to wetlands and alternative routing and construction techniques that may reduce wetland impacts. Likewise, the Secretary of State must consider impacts and alternatives related to the location of KXL's border crossing. Yet obviously an assessment of wetlands and border crossing impacts and alternatives is not the same as an assessment of the impacts of and alternatives to the proposed FRP. Therefore, the DSEIS must include a discussion not only of the potential impacts of PHMSA's approval of TransCanada's FRP on the environment, it must also consider alternatives to approval of the proposed FRP, including mitigation measures not already included in the FRP.

DOT NEPA rules also clarify that ERPs are federal actions for the purpose of NEPA. DOT Order 5610.1C (Sept. 18, 1979) ("DOT Order 5610.1C")[366] contains the DOT's NEPA procedural requirements that are applicable when other more specific requirements have not been promulgated. Section 4.a states:

> <u>Actions covered</u>. Except as provided in subparagraph c. below, the requirements of this Order apply to, but are not limited to, the following: all . . . regulatory actions, . . . approval of policies and plans (including those submitted to the Department by State or local agencies), . . . and any renewals or reapprovals of the foregoing.

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[363] *Spiller v. Walker*, No. A 98 CA 255 SS, 1998 U.S. Dist. LEXIS 18341 (W. D. Texas 1998) ("The Court concludes, however, that DOT's extensive and intricate oversight and approval of the [pipeline's] safety and emergency-response plan constitutes major Federal action significantly affecting the human environment."); *aff'd, Spiller v. White*, 352 F.3d 235 (5th Cir. 2003); *rehearing denied, Spiller v. White*, 2004 U.S. App. LEXIS 648 (5th Cir. 2004); *cert. denied*, *City of Austin v. Brownlee*, 2004 U.S. LEXIS 5526 (U.S., Oct. 4, 2004).

[364] DSEIS Table 1.9-1 lists all federal actions related to the project. Other than the Secretary of State's review of TransCanada's Application for a Presidential Permit to construct a border crossing for the pipeline, PHMSA's approval of the KXL FRP is easily the most substantial, highest profile and most controversial federal action triggered by the KXL proposal.

[365] 42 U.S.C. § 4332(C).

[366] Attached as Exhibit 96.

Thus, DOT rules also clarify that approval of FRPs is subject to NEPA.

ii. <u>The OPA, PSA, and PHMSA's regulations do not prevent submission of TransCanada's KXL FRP early enough to allow NEPA review</u>

The DSEIS includes the following <u>single</u> paragraph about the FRP:

> In addition to the ERP [purported PSA emergency response plan], a Pipeline Spill Response Plan (PSRP) [OPA FRP] would be prepared and submitted to PHMSA prior to initiating operation of the proposed Project, in accordance with requirements of 49 CFR Part 94. The PSRP would not necessarily need to be a separate report from the ERP. The PSRP would detail Keystone's spill response and describe the worst case scenario discharge, as well as the procedures in place to manage the discharge. The PSRP requires PHMSA review and approval; however, there is a 2 year grace period under which operation of the pipeline can proceed while PHMSA reviews and approves the PSRP. This period would allow PHMSA to review the proposed Project in its final, as-built state.

The DSEIS states that TransCanada is required to prepare two separate response plans that are "not necessarily separate. As previously discussed, this is an incorrect statement of federal statutory requirements. Further, the DSEIS implies that PHMSA is required to approve FRPs after the start of operations due to the "2 year grace period" such that it is not possible to review the FRP within the NEPA process. This statement has no foundation in federal law. Finally, the DSEIS implies that the plan must be prepared with knowledge of its "as-built state" such that it is not practical for TransCanada to prepare a proposed plan early enough to allow NEPA review. This assertion has no foundation in fact.

With regard to the 2-year period referenced by the DSEIS, the OPA states:

> Notwithstanding subparagraph (E), the President <u>may</u> authorize a … onshore facility to operate without a response plan approved under this paragraph, until not later than 2 years after the date of the submission to the President of a plan for the . . . facility, if the owner or operator certifies that the owner or operator has ensured by contract or other means approved by the President the availability of private personnel and equipment necessary to respond, to the maximum extent practicable, to a worst case discharge or a substantial threat of such a discharge. [367]

[367] 33 U.S.C. § 1321(j)(5)(F) (emphasis added); *see also*, 49 C.F.R. § 194.7.

The OPA expressly states that a pipeline may not operate unless it has a response plan that has been approved by the President, and that the only exception to this requirement is that the President may authorize a pipeline to operate without a response plan for up to two years after the date of submission of a plan if the President has not approved a submitted plan and if a pipeline's owner or operator certifies that it has the ability to respond to a worst case discharge.[368] Thus, PHMSA retains discretion to allow or prohibit operation of KXL without an ERP. There is no automatic "2 year grace period" provided by law. As such, nothing in the OPA prohibits PHMSA from requiring submission of an FRP prior to construction and operation to allow NEPA review. In fact, if PHMSA required early submission of an FRP, the "2 year grace period" would be needed only in unusual circumstances.

The "2 year grace period" is not a legal right, it is an administrative option that should not be used as a matter of course. OPA Section 1321(j)(5)(E)(i) requires that the President "promptly" review FRPs. Thus, the intent of Congress was to grant agencies limited discretion to allow facilities to continue to operate when an agency fails to approve an FRP prior to the start of operation, and to allow facilities in existence at the time the FRP requirement came into effect time to prepare their FRPs while continuing to operate. Congress did not intend to create a general rule that FRPs need not be approved until two years after the start of operation.

Unlike U.S.C.G. and U.S.E.P.A. regulations,[369] PHMSA's FRP regulations do not include any deadline for submission of an FRP for a new pipeline.[370] PHMSA's regulations do not require that FRP's be submitted for review prior to operation.[371] Instead, this rule is implied from the OPA's prohibition on operation without an FRP.[372] PHMSA apparently believes that because it has not specified a deadline for submission of FRPs, that therefore it cannot require pipeline operators to submit FRPs at any particular time. Such interpretation would mean that federal law allows pipeline operators to determine – in their sole discretion – when to submit an FRP as long as one is submitted before the start of operations.

In addition to being a remarkable abdication of federal authority, this interpretation is illegal because it ignores NEPA procedural requirements. As do the U.S.E.P.A and U.S.C.G., PHMSA has discretion to determine, either through guidance or regulation, when a pipeline operator must submit an FRP. Given this discretion, PHMSA must require submission of an FRP in time to allow NEPA review because:

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[368] 33 U.S.C. § 1321(j)(5)(G).
[369] 33 C.F.R. § 154.1025; 40 C.F.R. § 112.20.
[370] 49 C.F.R. § 194.119.
[371] *Id.*
[372] If an FRP is not submitted prior to operation, there would be no FRP pending approval such that the 2-year period would not apply.

- NEPA requires that “to the fullest extent possible: (1) the policies, regulations, and public laws of the United States shall be interpreted and administered in accordance with the policies set forth” in NEPA;[373] and
- NEPA review must be completed before a federal approval.

DOT Order 5610.1C states: “To the maximum extent possible, a single process shall be used to meet requirements for 'environmental studies, consultations and reviews.”[374] Section 17.A of the rule states: “A decision on the proposed action may not be made sooner than the times specified in CEQ l506.l0(b).” CEQ Rule 1506.10(b) prohibits decisions on proposed actions until after publication of a final environmental impact statement.

TransCanada cannot begin construction until after publication of a final environmental impact statement and receipt of required federal approvals. Since the OPA FRP is one of these approvals, PHMSA must require its submittal at a time that allows a full NEPA analysis.

iii. <u>Practical considerations do not prevent submission of TransCanada’s KXL FRP early enough to allow NEPA review</u>

TransCanada has claimed that it is not practically possible to submit a FRP to PHMSA for analysis in the DSEIS. This position is echoed by the DSEIS when it states: “[The two-year period] would allow PHMSA to review the proposed Project in its final, as-built state.”[375]

This position is specious. TransCanada’s Operations Manager, John Hayes, provided sworn testimony before the South Dakota Public Utilities Commission[376] that TransCanada typically begins preparation of its FRP about 18 months prior to the start of operation and submits this plan to PHMSA approximately one year before the start of operations. This testimony makes clear that it is not only possible but standard practice to prepare and submit FRPs well before the beginning of operations. Therefore, “as-built” information is not necessary for oil spill response planning. Mr. Hayes further testified that TransCanada planned to submit a proposed FRP for KXL by July 1, 2010, almost three years ago, making it likely that TransCanada has already prepared and perhaps even submitted a proposed FRP for PHMSA’s approval. In any case, there can be no doubt that TransCanada is fully capable of preparing its FRP years before the start of operations without reference to “as-built” information. Should as-built changes require modification of the FRP, these could be through PHMSA’s change process,[377] as is done by the U.S.C.G.[378] As such, there is no practical obstruction to submission of an FRP early enough to allow NEPA review.

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[373] 42 U.S.C. § 4332.
[374] DOT Order 5610.1C at 2, 3.
[375] DSEIS, at 4.13-75.
[376] Attached as Exhibit 97.
[377] 49 C.F.R. § 194.121.
[378] 33 C.F.R. § 154.1025.

We note that TransCanada does not intend to submit a new FRP for KXL, but rather will seek changes in its existing Keystone Pipeline System FRP. PHMSA approves new FRPs pursuant to 49 C.F.R. § 194.119 and approves changes to existing FRPs pursuant to 49 C.F.R. § 194.121. As TransCanada intends only to modify its existing FRP, many of its oil spill policies, methodologies, and requirements are already in existence; they simply have not been applied specifically to KXL within a publicly available plan. Since most of the spill response resources claimed to be available for KXL would be provided by TransCanada's existing spill response contractors and most of these resources are regional or even national, TransCanada's on-the-ground capabilities for KXL are likely already known to it or can be easily determined by its contractors. To the extent that TransCanada needs to plan to acquire additional resources, this is exactly the type of planning process that NEPA is intended to inform.

Although some aspects of KXL's design and route will be unknown prior to completion of the federal permitting process and construction, it is nonetheless possible and desirable to prepare a draft FRP that takes into account alternative routes and substantial design alternatives, because consideration of alternatives is part of NEPA's purpose. A review of the FRP in the DSEIS would in fact improve decision making for the overall project because this would allow consideration of spill response factors in pipeline routing, siting, and mitigation decisions.

Thus, there is no practical reason why TransCanada cannot submit a FRP early enough to allow full NEPA review, and doing so would substantially improve the NEPA process.

c. The Scope of NEPA Review Required for FRPs

The scope of the DSEIS's review of the KXL FRP is dependent on the policies and purposes of the OPA's FRP requirement. A more detailed review of FRP requirements and the scope of PHMSA's discretion is necessary because:

1) neither PHMSA nor the DOT have NEPA regulations or guidance specifically applicable to PHMSA's FRP process;[379] and
2) apart from the settlement agreement approved in *Spiller v. Walker*, it appears that PHMSA has never acted as a NEPA lead agency for any EIS or EA.

Due to PHMSA's lack of experience with NEPA it has not developed any formal administrative guidance to determine the proper scope of review of an FRP.[380] Accordingly, the following provides a brief summary of FRP statutory and regulatory requirements and PHMSA's scope of discretion. A more detailed discussion of PHMSA FRP requirements, and a comparison

[379] It appears that the only DOT NEPA guidance applicable to PHMSA is DOT Order 5610.1C, which is the default NEPA guidance applicable to all agencies within the DOT that do not otherwise have NEPA regulations.
[380] Environmental commenters point out the irony of the fact that the federal agency with sole responsibility for protecting the environment from injury by pipelines has almost never conducted a NEPA review for any of its actions.

of these requirements to U.S.C.G. and U.S.E.P.A. FRP requirements is included in *The Northern Great Plains at Risk: Oil Spill Planning Deficiencies in Keystone Pipeline System* (Nov. 23, 2010) ("Plains Justice Spill Response Study").[381]

The OPA imposes the following requirements on pipeline companies when they prepare FRPs:

> (D) A response plan required under this paragraph shall--
> (i) be consistent with the requirements of the National Contingency Plan and Area Contingency Plans;
> (ii) identify the qualified individual having full authority to implement removal actions, and require immediate communications between that individual and the appropriate Federal official and the persons providing personnel and equipment pursuant to clause (iii);
> (iii) identify, and ensure by contract or other means approved by the President the availability of, private personnel and equipment necessary to remove to the maximum extent practicable a worst case discharge (including a discharge resulting from fire or explosion), and to mitigate or prevent a substantial threat of such a discharge;
> (iv) describe the training, equipment testing, periodic unannounced drills, and response actions of persons . . . at the facility, to be carried out under the plan to ensure the safety of the . . . facility and to mitigate or prevent the discharge, or the substantial threat of a discharge;
> (v) be updated periodically; and
> (vi) be resubmitted for approval of each significant change.[382]

Thus, the OPA's substantive FRP requirements include:

1) consistency with the National Contingency Plan and Area Contingency Plans;
2) identification of a responsible company official and provision for immediate communications;
3) identification of private personnel and equipment necessary to remove "to the maximum extent practicable" a worst case discharge; and
4) a description of the training, equipment testing, drills, and response actions by company personnel.

The DSEIS should discuss each of these requirements. In addition, Part 194 imposes more detailed requirements. Key statutory and regulatory requirements for FRPs are discussed below.

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[381] Attached as Exhibit 98.
[382] 33 U.S.C. § 1321(j)(5)(D).

***Consistency with the National Contingency Plan and Applicable Area Contingency Plans* –** The OPA and PHMSA's regulations require that a pipeline operator demonstrate that its FRP is consistent with national and regional oil spill response plans.[383] These plans establish national standards and planning goals. However, the language of the OPA and Part 194 differs with regard to this requirement. The OPA states:

> (D) A response plan required under this paragraph shall--
> (i) be consistent with the requirements of the National Contingency Plan and Area Contingency Plans . . . .[384]

In contrast, Part 194 states:

> An operator must certify in the response plan that it reviewed the NCP and each applicable ACP and that its response plan is consistent with the NCP and each applicable ACP . . .

A certification unfounded on substantial evidence of consistency would not satisfy the OPA's requirement that a "response plan . . . shall be consistent . . . ."

***Determination of Response Zones* –** Due to the length of interstate pipelines, Part 194 requires that FRPs be based on delineated "response zones." Section 194.5 defines "response zone" as follows:

> Response zone means a geographic area either along a length of pipeline or including multiple pipelines, containing one or more adjacent line sections, for which the operator must plan for the deployment of, and provide, spill response capabilities. The size of the zone is determined by the operator after considering available capability, resources, and geographic characteristics.

The regulations allow operators to define their own response zones based on certain spill response factors. The regulations do not contain any objective standards against which PHMSA can evaluate a company's response zone demarcations. As such, the PHMSA Administrator has complete and unguided regulatory discretion when approving response zones.

***Determination of Worst Case Discharge* –** The OPA requires that an FRP's equipment and personnel requirements be based on preparation for a worst-case discharge scenario.[385] Section 1321(a)(24)(B) defines a worst case discharge for pipelines as "the largest foreseeable discharge

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[383] 49 C.F.R. § 194.107(b).
[384] 33 U.S.C. § 1321(j)(5)(D)(i).
[385] 33 U.S.C. § 1321(j)(5)(D)(iii).

in adverse weather conditions." PHMSA's regulations define "worst case discharge" by largely parroting the statutory language:

> Worst case discharge means the largest foreseeable discharge of oil, including a discharge from fire or explosion, in adverse weather conditions. This volume will be determined by each pipeline operator for each response zone and is calculated according to § 194.105.

Thus, worst-case discharges must be determined by a pipeline operator, subject to PHMSA review. Considerations of the impact of fire, explosions, and bad weather are included because these factors may impact a spill's geographic scope of damage as well as the amount of response equipment and personnel required.

In addition to this general definition, Section 194.105 provides a methodology for determining the volume of oil that would form that basis for the worst case discharge scenario:

> (a) Each operator shall determine the worst case discharge for each of its response zones and provide the methodology, including calculations, used to arrive at the volume.
> (b) The worst case discharge is the largest volume, in barrels (cubic meters), of the following:
> (1) The pipeline's maximum release time in hours, plus the maximum shutdown response time in hours (based on historic discharge data or in the absence of such historic data, the operator's best estimate), multiplied by the maximum flow rate expressed in barrels (cubic meters) per hour (based on the maximum daily capacity of the pipeline), plus the largest line drainage volume after shutdown of the line section(s) in the response zone expressed in barrels (cubic meters); or
> (2) The largest foreseeable discharge for the line section(s) within a response zone, expressed in barrels (cubic meters), based on the maximum historic discharge, if one exists, adjusted for any subsequent corrective or preventive action taken; or
> (3) If the response zone contains one or more breakout tanks, the capacity of the single largest tank or battery of tanks within a single secondary containment system, adjusted for the capacity or size of the secondary containment system, expressed in barrels (cubic meters).
> (4) Operators may claim prevention credits for breakout tank secondary containment and other specific spill prevention measures . . . .

The mere calculation of a volume does not fully encompass the statutory definition of this term, because the OPA requires analysis of not only the volume of oil spilled but the geographic extent of a worst case discharge. This distinction is important because the amount of response resources needed for a worst case discharge is more dependent on a spill's geographic extent than on the amount of oil spilled.[386] That is, the word "largest" refers not simply to the volume of a spill in barrels or gallons, but is also means its "largest" geographic extent. The requirement that explosions, fire, and weather all be considered is consistent with the need to define the geographic scope of a worst case discharge. These non-volumetric factors do not substantially affect the amount of oil that spills out of a pipeline after a rupture, but they may substantially impact the geographic extent of a spill by hindering containment activities or accelerating dispersal of oil into and through waterways. This definition is consistent with U.S. Coast Guard's practice of developing worst case spill scenarios.[387]

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[386] For example, a spill that only threatened waters of the U.S. but was contained to a small area by topography would require substantially lower amounts of response resources than a spill directly into a major river or one of the Great Lakes during severe thunderstorms or blizzards. Since the purpose of Section 1321 is to ensure that adequate equipment and personnel are available to respond to and clean up a real-world worst case oil spill, and it is impossible to estimate this need without consideration of the possible geographic extent of an oil spill, mere calculation of a worst case discharge volume cannot accomplish the purposes of the CWA.

[387] The U.S.C.G. develops specific worst case oil discharge scenarios, e.*.g*., U.S.C.G Sector Baltimore. Upper Chesapeake Estuary Area Contingency Plan (2009) § 9420.3, 9420.3. This ACP defines the worst case vessel discharge scenario within its scope of jurisdiction by considering the following factors:

1. Historical spill considerations - Based on vessel traffic patterns, types of vessels transiting the area and cargos carried, the worst case area scenario involves a 12 million gallon capacity tanker carrying No. 6 fuel oil (Bunker C) in a collision with a towed barge carrying 120 containers of non-hazardous cargo. A collision was chosen over a large vessel grounding because the soft bottom of the Chesapeake Bay and typical sea conditions would not cause a vessel to break apart and founder. The location is north of Smith Point, VA near the confluence of the Chesapeake Bay and the Potomac River. It was chosen for the following reasons:

a. Remoteness from response resources in the Baltimore and Norfolk area.

b. The area is surrounded by land so that shoreline would be impacted regardless of wind and current direction.

c. The incident is likely to impact Virginia waters and shores, in addition to those of Maryland, requiring coordinated efforts of state and federal agencies in both states.

d. The area is near numerous environmentally sensitive waters, marshes and tidal areas.

e. Tank vessels inbound for Baltimore or the oil transfer facilities at Piney Point routinely transit the area.

f. The region is sparsely populated and thus lacks the infrastructure (e.g. manpower, accommodations, port facilities, beach access, etc.) needed to support large scale cleanup operations.

2. Hazard assessment - Fire hazard, health hazard, economic and critical area impact including probable disruption of shipping to Baltimore and Washington, adverse impact on the commercial and charter fishing business in this region by the real or perceived threat to fish and shellfish, and impact on tourist and recreational industries.

3. Vulnerability analysis - Inclement weather, mechanical failure and human error are potential contributions to the incident.

4. Risk assessment - High traffic volume and channel convergence pose substantial risks.

Identification of Spill Response Resources – The heart of the OPA is its requirement that oil companies acquire and preposition spill response equipment and trained personnel that are capable of containing and cleaning up spilled oil. Section 194.107 contains the following response resource requirements:

> (a) Each response plan must include procedures and a list of resources for responding, to the maximum extent practicable, to a worst case discharge and to a substantial threat of such a discharge.
>
> * * *
>
> (c) Each response plan must include:
> (1) A core plan consisting of --
>
> * * *
>
> (v) Response activities and response resources . . .

In turn, Section 194.5 defines "maximum extent practicable" as:

> Maximum extent practicable means the limits of available technology and the practical and technical limits on a pipeline operator in planning the response resources required to provide the on-water recovery capability and the shoreline protection and cleanup capability to conduct response activities for a worst case discharge from a pipeline in adverse weather.

Section 194.5 defines "response resources," to mean:

> Response resources means the personnel, equipment, supplies, and other resources necessary to conduct response activities.

Section 194.115, which is the only section in Chapter 194 that describes required response resources, is provided <u>in its entirety</u> as follows:

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5. Seasonal considerations - All seasons present significant concerns. However, the summer would pose the most difficult set of circumstances as it would be the height of the recreational boating season as well as the primary time frame for fin fish spawning in this area.

The U.S.C.G. plays out this specific scenario in § 9440.3.1.1 by discussing the specific challenges and resource needs in a response to this scenario. Such scenarios provide evidence of actual planning for spill response and go beyond providing evidence of a general awareness of generic spill response planning tactics.

> (a) Each operator shall identify and ensure,[388] by contract or other approved means, the resources necessary to remove, to the maximum extent practicable, a worst case discharge and to mitigate or prevent a substantial threat of a worst case discharge.
> (b) An operator shall identify in the response plan the response resources which are available to respond within the time specified, after discovery of a worst case discharge, or to mitigate the substantial threat of such a discharge, as follows:
>
> | | Tier 1 | Tier 2 | Tier 3 |
> |---|---|---|---|
> | High volume area | 6 hrs | 30 hrs | 54 hrs. |
> | All other areas | 12 hrs | 36 hrs | 60 hrs. |

Significantly, **PHMSA's regulations contain no standards whatsoever for the amount of required response resources** but instead merely parrot the very general statutory requirement that the resources be those "necessary to remove" a worst case discharge.[389] That is, the regulations specify the timeframes in which resources must arrive and requires that a pipeline operator identify these resources, but the regulations do not specify the amount of resources required or provide any methodology for determining such amount. Regardless, FRPs must comply with the OPA.

The timeframes are defined based on whether or not an area is a "high volume area," which Section 194.5 defines as:

> High volume area means an area which an oil pipeline having a nominal outside diameter of 20 inches (508 millimeters) or more crosses a major river or other navigable waters, which, because of the velocity of the river flow and vessel traffic on the river, would require a more rapid response in case of a worst case discharge or substantial threat of such a discharge. Appendix B to this part contains a list of <u>some</u> of the high volume areas in the United States.

[388] In the statutory language, there is a comma after the word "identify." Section 1321(j)(5)(D)(iii) states that response plans shall "identify, and ensure by contract or other means approved by the President the availability of, private personnel and equipment necessary to remove to the maximum extent practicable a worst case discharge (including a discharge resulting from fire or explosion), and to mitigate or prevent a substantial threat of such a discharge . . . ." PHMSA's regulations remove this comma and instead insert a comma after the word "ensure," thereby changing the meaning of this language. The statute's plain language requires that FRPs identify resources, and that these resources may by ensured by contract. PHMSA's language appears to allow a contract to identify resources rather than the FRP itself. Such interpretation would be a violation of law.

[389] *Cf.* 33 U.S.C. § 1321(j)(5)(D)(iii).

Emphasis added. Appendix B contains a relatively short list of locations along rivers in the U.S., but as noted above, this list is not intended to be inclusive. "Major river" is defined as:

> Major river means a river that, because of its velocity and vessel traffic, would require a more rapid response in case of a worst case discharge. For a list of rivers see "Rolling Rivers, An Encyclopedia of America's Rivers," Richard A. Bartlett, Editor, McGraw-Hill Book Company, 1984.

Thus, where oil may be spilled into a fast flowing river sufficient in size to have vessel traffic, FRPs are required only to <u>identify</u> which resources would be at the spill within six hours, rather than twelve hours. The reason for this rule is that major rivers usually have fast currents with the result that oil may spread very quickly if not contained by booms. To protect each identified High Volume Area, PHMSA's regulations require that a pipeline company identify what response resources ("personnel, equipment, supplies, and other resources necessary to conduct response activities") would be on-scene at that High Volume Area within six hours of notification of a rupture.

This being said, **PHMSA's regulations contain no detailed mandatory requirements for how a pipeline company must calculate the amount of equipment and personnel needed to respond to spills into High Volume Areas, or anywhere else for that matter**. Given that there is no simple relationship between the amount and type of oil spilled and the amount of response equipment needed for such spill, it is clear that PHMSA in fact has no objective standards for determining how much spill equipment and personnel are needed to respond to a pipeline spill. Thus, the PHMSA Administrator has retained for herself unfettered and unguided discretion to determine if a pipeline company's estimates of equipment needs complies with federal law.

Appendix A to 49 C.F.R. Part 194 ("PHMSA Appendix A") provides non-mandatory "guidelines" for preparation of response plans that reference a limited set of materials prepared by other agencies. The introduction to Appendix A states:

> This appendix provides a recommended format for the preparation and submission of the response plans required by 49 CFR Part 194. Operators are referenced to the most current version of the guidance documents listed below. Although these documents contain guidance to assist in preparing response plans, their use is not mandatory:
> (1) The "National Preparedness for Response Exercise Program (PREP) Guidelines" (PREP), which can be found using the search function on the USCG's PREP Web page, http://www.uscg.mil;
> (2) The National Response Team's "Integrated Contingency Plan Guidance," which can be found using the search function at the National Response Center's Web site, http://www.nrt.org and;

(3) 33 CFR Part 154, Appendix C, "Guidelines for Determining and Evaluating Required Response Resources for Facility Response Plans."

PHMSA Appendix A is essentially a recommended outline for the contents of FRPs. It does not include any binding standards for FRPs, nor does it contain any detailed guidance for determining the amount of spill response equipment and personnel that must be provided by pipeline operators. Even though it incorporates by reference one document prepared by the Coast Guard and one by the National Response Team, use of these documents and the standards they contain is not mandatory. The third document[390] listed is of particular interest because it contains mandatory USCG FRP standards[391] for the type, general location, and amount of equipment required to be identified FRPs subject to USCG approval. Whereas PHMSA's regulations do not contain any mandatory equipment standards for the FRP's it approves, the USCG regulations provide USGC personnel with meaningful detailed standards for evaluation of USCG-approved FRPs.

It is remarkable that PHMSA's FRP regulations do not contain detailed standards for equipment or personnel needed to respond to oil pipeline spills, because determination of the sufficiency of response equipment is not a simple task. It appears that PHMSA allows pipeline companies to define for themselves the extent of their response zones and the type, amount, and location of response equipment and personnel needed to respond to these discharges, but then provides no meaningful standards that would allow PHMSA staff to determine whether or not a pipeline's FRP is in compliance with the CWA. Although PHMSA retains ostensible approval authority over pipeline FRPs,[392] absent more detailed standards it is impossible to know the specific standards that the PHMSA Administrator might use in the FRP approval process. This lack of detailed and mandatory pipeline FRP standards is a significant weak link in the federal regulatory chain that must be strengthened. PHMSA's failure to promulgate mandatory detailed standards for pipeline FRPs stands in marked contrast to both the EPA and USCG regulations implementing the same statutory authority.

d. There is an Urgent Need for the President to Provide Express Commitments Within the DSEIS to Improve the KXL FRP

Recent spills, such as the rupture of Exxon Mobil's Pegasus Pipeline on March 29, 2013, that released heavy Canadian crude into an American suburb, highlight both the basic truth that

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[390] 33 C.F.R. Part 154, Appendix C ("USCG Appendix C").
[391] *See, e.g.*, 33 C.F.R. § 154.1045(b) and (e), which respectively require the use of Appendix C when determining equipment operating criteria and when calculating the quantity of response resources required within specified timeframes to respond to a worst-case discharge. The U.S.E.P.A. has also promulgated a required quantified methodology for determining the type and amount of equipment required to respond to a worst case discharge. 40 C.F.R. Part 112, Subpart D, Appendix E (Determination and Evaluation of Required Response Resources for Facility Response Plans).
[392] 49 C.F.R. § 194.119.

pipelines rupture and the ongoing need for responsible and aggressive spill response planning. Moreover, these spills demonstrate that the industry is poorly prepared to respond rapidly to pipeline spills, and that part of the reason for this failure is the utter ineffectiveness of PHMSA FRP regulations and oversight. These spills also provide real-world experience against which to compare TransCanada's existing Keystone System FRP.

i. Recent spill history demonstrates the need for aggressive spill response capability

The recent spill in Mayflower, Arkansas, highlights the ongoing need for pipeline safety and spill response, but as its cause and spill response have not yet been fully analyzed, only limited conclusions can be drawn from it. The best studied recent example of a major pipeline spill and response is Enbridge's Line 6b spill near Marshall, MI, that ultimately damaged about 35 miles of the Kalamazoo River. The facts related to this spill are described and discussed in the National Transportation Safety Board's ("NTSB") report on this spill ("NTSB Line 6b Report")[393] and in the Great Plains at Risk Report.

On July 26, 2010, Enbridge reported that its 30-inch diameter 6B Pipeline had ruptured and released an estimated 843,444 gallons of crude oil (approximately 94 semi tanker trucks) of diluted bitumen in a rural area about one mile south of Marshall, Michigan.[394] Investigation showed that the oil flowed into a culvert, which led to Talmadge Creek, then followed the creek to the Kalamazoo River, ultimately contaminating about 30 to 35 miles of the River before it was contained. After the spill, the River flooded and stranded oil on floodplains, wetlands, backwaters, and islands. Importantly, the spill threatened to flow all the way to Lake Michigan, thereby fouling many more miles of river, as well as the lake's shoreline.

At the time of the rupture, the 6B Pipeline was transporting a very heavy crude oil from Canada, called "Cold Lake Blend," which is a mix of tar-like bitumen from the Canadian tar sands and a liquid material called "diluent." The diluent is mixed with the bitumen to make it more liquid so that it can be pumped through the pipeline. Diluent is often made using "natural gas liquids," which are light oils that are produced by natural gas wells as a byproduct.

The operating temperature of the pipeline at the time of the spill has not been disclosed, but bitumen blends are typically transported at higher temperatures, because elevated temperatures also make heavy oils less viscous. Elevated pressures and temperatures may also result in an immediate off-gassing of diluents, thereby creating a strong smell when the oil is exposed to air, with the result that heavy blended oils may revert to bitumen when spilled.

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[393] Attached as Exhibit 98.

[394] NTSB Line 6b Spill Report at xii; U.S. House of Representatives, Committee on Transportation and Infrastructure, Staff Report for September 15, 2010, Hearing on Enbridge Pipeline Oil Spill in Marshall, Michigan, September 14, 2010 (House Staff Memo).

The type of oil spilled is important to cleanup efforts because the properties of the spilled oil determine how it behaves when spilled, where it ends up, and the types of equipment needed to clean it up. Lighter petroleum products, such as gasoline and diesel fuel, evaporate quickly, with the result that a large amount of the spill ends up in the air and not in the water or on land, and the oil that does not evaporate floats on water. In contrast, only a small amount of the bitumen evaporates, and it can become heavy enough to sink in water.

As a result, cleanup efforts for lighter crude oils expect to recover a relatively small portion of the spilled oil, and if the spill is into water, the oil will need to be removed by skimming the oil from the surface of water. Further, spill response equipment and training typically focuses on removal of floating oil, in part because light oil spills, such as diesel fuel leaks from boats, are more common. In contrast, cleanup of very heavy crude oil can be expected to recover a higher proportion of the spilled oil because less of the oil evaporates or is dispersed into water. Further, the heaviest components of dilbit ultimately sink. The result is that cleanups of dilbit require removal of the oil by dredging, and not just by skimming.

The Cold Lake Blend spilled by the 6B Pipeline had an American Petroleum Institute (API) gravity rating of 11. In contrast, bitumen has an API rating of around 8 and diluents have an API rating of 69.3.[395] If a rating is over 10, then the oil will float when first spilled. However, once the oil is exposed to air, the diluent will begin to evaporate and the oil will become heavier, with the result that some of it will sink. In fact, a very large amount of the oil spilled by Line 6b sank, with the result that removal efforts are ongoing nearly three years after the spill

Time is of critical concern when responding to oil spills, because the longer the delay in stopping flows and capturing released oil, the farther the oil contamination and damage spreads, making cleanup more difficult and expensive. The National Transportation Safety Board (NTSB) provides great detail about the sequence of events.[396] Approximately 17 hours passed between the start of the spill and the time that Enbridge received notification of the spill from a natural gas utility employee. This means that the spilled oil was already at or near the Kalamazoo River before any spill containment activities began. The following is a summary timeline of events preceding Enbridge's phone calls to the federal government notifying it about the rupture.[397]

Sunday, July 25, 2010

5:58 PM: **Pipeline pump automatically shuts down** when Enbridge control center in Edmonton, Canada, receives **low pressure alarm**; the control center attributes the

[395] House Staff Memo; Environment Canada Cold Lake Diluent Reference Sheet from http://www.etc-cte.ec.gc.ca/databases/OilProperties/oil_prop_e.html.
[396] NTBS 6b Spill Report Section 1.2.
[397] House Staff Memo p. 3-6.

	alarm to a “column separation,” meaning that they thought a vapor bubble formed in the pipeline.
9:25 PM:	**First 911 calls** from residents near the rupture due to odor

Monday, July 26, 2010

4:04 AM:	**Enbridge restarts pipeline**
4:12 AM:	**Volume balance alarm** (less oil in pipeline downstream than upstream)
4:17 AM:	Second volume balance alarm
4:22 AM:	Third volume balance alarm
4:36-4:57 AM:	Several more volume balance alarms
5:03 AM:	**Enbridge control center turns off Pipeline pumps**
6:30-8:00 AM:	Residents notice strong odor on way to work
7:00 AM:	Local resident collects oil sample from Talmadge Creek
7:10 AM:	**Enbridge restarts pipeline pumps**
7:12-7:42 AM:	Five additional volume balance alarms
7:55 AM:	**Pipeline pumps shutdown and downstream valve closed**
9:49 AM:	Technician called to check a pump station about three-quarters of a mile from the rupture
11:18 AM:	A gas utility calls Enbridge to report on oil in Talmadge Creek
11:20 AM:	Enbridge begins closing valves upstream and downstream of the rupture
11:41 AM:	**Enbridge personnel confirm leak** and begin to respond to the spill
1:29 PM:	**Enbridge reports spill to the federal government**

From this timeline it appears that Enbridge operated the pipeline pumps for a total of approximately two hours after rupture. Further, Enbridge’s failure to interpret its SCADA data correctly allowed the dilbit to flow out of Talmadge Creek and miles down the Kalamazoo River, thereby resulting in a substantially more damaging and expensive spill than would have happened if the spill was discovered and isolated immediately.

Once Enbridge confirmed the spill, it began using its own spill response equipment and started calling in private clean up companies. Enbridge has not publicly disclosed the exact amount of spill equipment and personnel that arrived on each of the first three days of the spill.

Due to the very large amounts of equipment needed to respond to major spills, pipeline companies do not own the vast majority of equipment needed, but rather contract with private spill cleanup contractors who transport in equipment from locations across the U.S. These contractors first brought in equipment from southern Michigan, the Chicago and Detroit metropolitan areas, and western Ohio, but given the amount of equipment used, it is likely that much of the equipment ultimately used was brought in from the across the eastern U.S.

The timing and quantity of response resources can substantially impact the effectiveness of spill response. The location of spill equipment relative to the spill is important because rapid response can significantly reduce the impacts of a spill. Oil can move two to five or more miles down a river per hour, meaning that when oil spills into moving water it is important that an initial wave of personnel and equipment sufficient to contain the spill be on site within hours.

Enbridge was fortunate to the extent that the spill happened near caches of its own equipment and relatively near large spill cleanup contractors in Chicago and Detroit. Also, Enbridge benefitted from the fact that the pipe ruptured relatively close to cities and towns with sufficient lodging and food for a large number of temporary spill response workers. If this spill had been far from one of its equipment caches and services for response workers, its spill response would have been much slower.

The following table, based on Enbridge reports to the media, identifies the amount of certain types of equipment and personnel brought in during the first week of the response, but it also provides the largest amounts reported by Enbridge at any time for two months after the rupture.

Enbridge Report Date	Personnel	Boom Deployed (ft)	Boats	Skimmers	Vacuum Trucks	Frac Trucks	Tanker Trucks
First Week After Rupture							
26-Jul-10	50						
27-Jul-10	150						
28-Jul-10	250						
29-Jul-10	450	12,310	15	14	43	Yes	Yes
30-Jul-10	631	25,000	36		71	>64	12
31-Jul-10	683	60,000	40	39	76	77	17
1-Aug-10	730	69,000	43	48	79		19
Maximum Quantity of Personnel and Equipment Reported by Enbridge							
Through 30-Sep-10	**2,055**	**157,000**	**43**	**48**	**79**	**77**	**19**

Thus, Enbridge brought in a total of **over 2,000 personnel, over 150,000 feet (28 miles) of boom, 175 heavy spill response trucks, 43 boats, and 48 skimmers**. This being said, it is certain that Enbridge also deployed substantial numbers of spill response vans and trailers with portable equipment and hand tools, boom trailers, portable storage tanks and pumps, trailer tow vehicles, pickups and other light vehicles, dump trucks, excavators, and aircraft. The NTSB estimated, as of July 2012, that the cost of responding to this spill was $767 million,[398] but now it is widely estimated that the final cost will exceed $1 billion largely due to the cost of dredging bitumen.[399]

The response to this spill required a substantial amount of equipment. Containment of large spills into creeks and rivers typically require multiple boom and skimmer sites, each set up and serviced by crews, portable tanks, pumps and/or vacuum trucks and tank trucks. Most of the 48 skimmers deployed by Enbridge captured oil from different boom sites, and each skimmer would need to be serviced 24/7 by pumps, tanks, trucks, and the crew to operate them. Likewise, each vacuum truck would need a crew to operate and maintain it, and would likely need to be emptied into other tank trucks so that vacuuming could continue without interruption. This being said, Enbridge was not prepared to respond to submerged dilbit early in the spill response such that submerged oil spread under booms throughout a very large geographic area.

Because power equipment cannot access all areas contaminated with oil, oil spill cleanups require that large areas be protected by hand placement of booms or cleaned by hand using tools from spill response trailers and vans. This type of handwork is enormously labor intensive and requires substantial amounts of hand tools and supplies, such as absorbent pads. This work is often dirty and dangerous and time is of the essence, so workers need to be trained both in spill response techniques and safety.

The equipment listed by Enbridge plays specialized roles in spill cleanup efforts. A brief description of the types and intended purpose of this response equipment follows.

> **Boom –** Oil spill booms are floating barriers intended to contain oil spills in calm non-flowing waters and to channel oil toward skimmers or vacuums in moving water. Boom is categorized as either containment boom or absorbent boom, the difference being that absorbent boom is made of material that also absorbs spilled oil. Different types of boom are needed depending on whether the water is flowing or still, and depending on how rough the water is. Thus, boom intended for use in the ocean or Great Lakes is not appropriate for use on stream and rivers, and vice versa. Likewise, the type of boom needed for a major river is not the same as would be required for a creek. Boom is measured by length and height, with longer and higher boom used in open water, while shorter height and length boom is used in moving waters. Boom is not effective in containing submerged oil.

[398] NTSB Line 6b Spill Report at xii.
[399] E.g., Lancing State Journal, Enbridge: Oil Spill Cleanup Costs Nearing $1 billion (Mar. 21, 2013); available online at http://www.lansingstatejournal.com/article/20130321/NEWS01/303210069/Enbridge-Oil-spill-cleanup-costs-nearing-1-billion .

Boats – Unlike ocean spills where larger vessels participate in containment and cleanup, inland spills into lakes, streams, rivers, and wetlands requires the use of different types of boats, depending on the nature of the water. In large rivers, larger boats with powerful motors are required to position boom across river currents. In smaller river and lakes, boats intended for use in shallow water are needed. Work in wetlands or partially frozen lakes and rivers may require the use of airboats or other specialized craft. Since major spills into rivers also require the placement and maintenance of dozens of boom sites, the ability to ferry cleanup crew to islands and shorelines that are not accessible by land, and vessels to monitor the spread of oil and response efforts, spill responders may need dozens of boats.

Skimmers – Oil skimmers remove floating oil from water. As with boom, different types of skimmers are required for the ocean, lakes, rivers, and streams. Common types include weir, oleophilic (oil attracting), and suction skimmers, each of which uses a different technique to collect oil. On the ocean and lakes, boats use boom to gather or surround oil, which is then removed with skimmers. In rivers and streams, a series of booms are used to channel floating oil toward skimmers located near the shore where the water is still enough to allow skimming. Size and type are also important. A large skimmer suitable for use on the ocean or Great Lakes would not be usable in a smaller river or stream. Further, some skimmers, such as suction skimmers, work best in smooth water and tend to become clogged with debris so require constant attention. Skimmers are not 100% efficient at capturing only oil, but instead capture a mixture of oil and water, which is pumped into tanks for transportation to processing facilities that separate the oil and water so the oil can be reclaimed.

Vacuum Trucks – An important way to remove oil from inland waters and land is to vacuum it up. Typically, cleanup crews vacuum oil using vacuum trucks, but other types of portable vacuum units may also be used. Depending on the type of truck, vacuum trucks can collect oiled water, rocks, dirt and vegetation and may have air filters to limit chemical emissions from the captured oil. For obvious reasons, vacuum trucks are not typically used in open water spills, although it is possible to place them on barges. Unlike more specialized spill response equipment such as skimmers and boom, vacuum trucks are also used to clean tanks and for other industrial and commercial cleaning needs, and are also used in responses to spills from tanker trucks and rail cars. As a consequence, vacuum trucks are relatively common in industrial areas, but uncommon in rural areas.

Frac Trucks and Tanks –"Frac trucks" and "frac tanks" are mobile storage tanks, located either on trucks or towed, that are used to collect a variety of liquids, typically in oil field operations.

Tanker Trucks – Used to transport collected oil to disposal or recycling locations. As with vacuum trucks, tanker trucks capable of transporting oil are relatively common in industrial areas and in regions with producing oil wells.

Temporary Storage Tanks – Although not quantified by Enbridge, a variety of other types of portable and fixed temporary oil storage tanks are also required for oil spill cleanup operations. As noted, mixed oil and water is collected by skimmers or vacuums and then pumped into nearby tanks or tank trucks. Next, this mix is transported from skimming and vacuuming sites to a larger fixed tank, that may or may not be at the processing facility. When a large amount of oil is spilled, the process of capturing oil at many locations and gathering it for final processing requires the use of large numbers of temporary tanks of many sizes.

One of the lessons learned from the Line 6b spill is that construction of dams to contain spilled oil may be far more effective than tactics that focus on removal of floating oil. The equipment and materials needed for dam construction is not the same as required for removal of floating oil from open water. There can be no doubt that responding to a major oil spill from a large pipeline presents substantial logistical challenges and requires a very large amount of personnel and equipment. Further, the types and pre-positioned locations of equipment are critical to limiting the damage caused by a spill and the overall success of a spill response, because an immediate rapid response limits both damage caused by the spill and the difficulty, cost, and effort of removing widespread oil.

In response to the Line 6b spill, the National Transportation Safety Board issued a report[400] that found that Enbridge's "initial containment efforts and tactics proved ineffective in preventing substantial quantities of oil from spreading and traveling miles downstream of the rupture."[401] The NTSB described how Enbridge crews ineffectively used oil spill containment tactics designed to stop the spread of oil floating on open water or slow moving rivers, rather than the spread of dilbit in fast moving creeks and rivers.[402] The NTSB found:

> Enbridge crews primarily deployed sorbent booms in the fast-flowing Talmadge Creek, which, according to industry and Federal guidance, is an ineffective method of containing oil except in stagnant waters. Sorbent booms are generally used for small spills or as a polishing technique to capture sheen escaping from skirted oil booms, not as a principal containment method for a large release. Had more effective containment measures been placed at strategic locations along Talmadge Creek—such as installing plywood sheet underflow dams over the seven culvert pipe stream crossings located between the release site and the Kalamazoo River—less oil might have entered the Kalamazoo River.[403]

[400] *See*, Ex. 98.
[401] NTSB Line 6b Spill Report at 105.
[402] *Id*. at 106-07.
[403] *Id*. at 107.

Moreover, Enbridge was fortunate because materials required for making a dam happened to be located at its pump station but not as part of its spill response inventory.[404]

In the final analysis, Enbridge's response to its Line 6b spill was a planning failure. Enbridge operators misinterpreted data related to pumping dilbit, its spill response planners had prepositioned too little equipment and the wrong materials to respond to a dilbit spill, and its crews were poorly trained to respond to a dilbit spill. In fact, the Chair of the NTSB in summarizing Enbridge's response is reported to have said, "Their employees performed like Keystone Kops and failed to recognize their pipeline had ruptured and continued to pump crude into the environment."[405] But if Enbridge employees were the actors and Enbridge managers the directors of this tragedy, then as discussed below, PHMSA acted as its producer.

ii. <u>NTSB Report on the Enbridge Line 6b Spill highlights significant regulatory perversions in PHMSA's FRP Regulations and the practical impossibility of effective implementation</u>

The NTSB Line 6B Report also examined the effectiveness of PHMSA FRP regulations. The NTSB found that PHMSA regulations do not "provide any specific guidance for the amount of resources that must arrive on the scene of a discharge."[406] It noted that PHMSA in its rulemaking for Part 194 had opted to let operators individually determine this amount. The NTSB also concludes that it is "improbable that PHMSA would be able to perform an adequate review of facility response plans or enforce Federal requirements that pipeline operators identify and ensure that adequate response resources are available to respond to worst-case discharges."[407] Put another way, PHMSA's response resource regulations are unenforceable. The NTSB also found that, "[e]ssentially, the regulations allow the pipeline industry to dictate the requirements of an adequate spill response and to determine whether those requirements have been met."[408] As a consequence, communities along the pipeline route can expect no greater amount of spill response resources from TransCanada than those that TransCanada, in its sole discretion, believes is due them.

To demonstrate that meaningful standards are practicable, the NTSB compares PHMSA's response resource regulations to those of the U.S.C.G. and the U.S.E.P.A. It concludes, "PHMSA's regulatory requirements for response capability planning do not ensure a high level of preparedness equivalent to the more stringent requirements of the Coast Guard and the EPA," and "PHMSA's regulations for oil pipeline response planning are clearly inferior when compared to similar Coast Guard and EPA requirements."[409] The NTSB recommended that "PHMSA

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[404] *Id*.
[405] Upstream Online, US: Enbridge like 'Keystone Kops' in spill (July 10, 2012).
[406] *Id*. at 109.
[407] *Id*.
[408] *Id*. at 113.
[409] *Id*. at 110.

amend 49 CFR Part 194 to harmonize onshore oil pipeline response planning requirements with those of the Coast Guard and the EPA."[410]

The NTSB found that PHMSA has only 1.5 full-time employees managing about 450 response plans, far fewer than either the U.S. Coast Guard or U.S.E.P.A, despite the fact that it receives significantly greater funding from the Oil Spill Liability Trust Fund,[411] which, ironically, is not funded by dilbit shippers such as Enbridge.[412] It also found that PHMSA had approved Enbridge's FRP within two weeks of its receipt without comment and that only a "cursory" review of the plan could have been conducted within this time period. It does not state that the part of the Enbridge Lakehead System FRP applicable to the Line 6b, the Chicago Region Response Zone,[413] is comprised of 359 pages of information, and that this response zone is just one of four included in the entire FRP, which covers Enbridge's entire U.S. pipeline system in an area that stretches from North Dakota to Michigan to Oklahoma.[414] Given the length and complexity of this document, it is almost certain that all PHMSA staff did was complete PHMSA's Facility Response Plan Review form[415] to confirm that the FRP contained all required parts. Moreover, the NTBS Line 6b Report also found that PHMSA does "not perform on-site audits to verify the content and adequacy of plans before approving them. In contrast, both the Coast Guard and the EPA conduct on-site audits and plan reviews after the initial review and approval of the submitted plan."[416] Thus, PHMSA in all likelihood just bean counts whether an FRP has all required parts, rubber stamps whatever pipeline companies' submit, and then ignores FRP's until the process repeats itself.

The NTSB report makes abundantly clear that PHMSA's spill response regulations and its implementation of these regulations is a travesty of the OPA. In response to this evidence, the NTSB reported, "PHMSA stated that it plans to include a review of lessons learned when it reviews the Enbridge facility response plan due for renewal <u>in 2015 or when Enbridge next amends its plan</u>."[417]

Remarkably, the DSEIS ignores all of this evidence about the unreliability of PHMSA's FRP administration and cites the NTSB report <u>only</u> in the context of its investigation into whether dilbit represents a greater threat than other types of oil.[418] As for the DSEIS's conclusions about the Line 6b spill, it draws <u>only</u> the following two bland conclusions:

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410 *Id*.
411 *Id*. at 113.
412 I.R.S. National Office Technical Memorandum 201120019 (Jan. 12, 2011) at 3 ("Accordingly, tar sands imported into the United States from Country by Company are not subject to the excise tax on petroleum imposed by § 4611.")
413 Attached as Exhibit 99.
414 Enbridge Liquids Pipeline System (Lakehead System) FRP Cover Sheet at 4.
415 Attached as Exhibit 100.
416 *Id*.
417 *Id*. at 112.
418 DSEIS, at 4.13-7.

- "As the response to the Marshall Michigan Dilbit spill continues to mature and evolve, the lessons learned from the response and recovery efforts should be considered to facilitate the implementation of proper response planning and response strategies to improve the overall response to Dilbit spills."

- "When developing the ERP, Kalamazoo River Spill lessons learned would be considered, including ensuring consultants are contracted as appropriate to facilitate a large-scale and prompt response; developing source containment plans including strategies and tactics; minimizing response times with appropriate equipment; identifying equipment resources required to respond to sunken and submerged oil, and ensuring personnel are appropriately trained."

This language mirrors PHMSA's utterly noncommittal and bureaucratically passive response to the NTSB.

If PHMSA's implementation of the OPA is a travesty, then the DSEIS's reliance on PHMSA's administration of the KXL ERP as "recommended mitigation" is deeply cynical and represents profound bad faith with the communities threatened by KXL and the American people.

To rectify this breach of faith, the Administration must require TransCanada to submit a draft of the Keystone System FRP that includes all of the changes proposed by TransCanada related to KXL, accept public comment on this draft pursuant to NEPA, and commit to specific substantive improvements within the DSEIS.

e. The DSEIS Fails to Analyze the KXL FRP as Required by NEPA

The DSEIS admits that it does not consider KXL-specific oil spill response requirements because these are included only in the FRP, which the DSEIS implies cannot be included in this NEPA process due to legal and practical constraints. Instead, the DSEIS includes (1) a general discussion of oil spill planning in Section 4.13.5; and (2) a mocked up ERP provided by TransCanada that is based on the Keystone Pipeline System FRP for its existing pipelines. The information provided in these documents is academic, non-specific, and/or unsupported by substantial evidence, and therefore is completely inadequate under NEPA.

i. <u>The DSEIS is fundamentally flawed because it provides and discusses none of the changes to the Keystone Pipeline System FRP required to operate KXL</u>

Because the DSEIS takes the position that the FRP need not be analyzed as part of the DSEIS, the DSEIS does not include any of the actual FRP or analyze any of the changes to the Keystone Pipeline System FRP required for operation of KXL. As a consequence, it is impossible for us, any other commenter, or even any federal or state agency to comment on the FRP. In particular, since the DSEIS admits that the FRP is not available for review, it is impossible for PHMSA to conduct a NEPA analysis for its review of TransCanada's FRP. Therefore, the DSEIS's review of PHMSA's major federal action is fundamentally flawed. As well, to the extent that the FRP serves as mitigation for the the State Department's Presidential Permit decision, other major federal actions, and the project as a whole, the DSEIS fails to provide any basis for comment on or analysis of critical mitigation of great public concern.

ii. <u>The spill response information provided in the DSEIS is not sufficient under NEPA</u>

DSEIS Section 4-13.5.2, Spill Response, bases its analysis on a document prepared by TransCanada called an "Emergency Response Plan" that is included in Appendix I ("App. I ERP"), even though this document has no legal authorization separate from that for TransCanada's FRP. Not surprisingly, the generic nature of TransCanada's mocked up plan is strongly reflected in DEIS Section 4-13.5.2.

A. DSEIS Section 4.13.5.2 is almost entirely generic and the information provided is insufficient for a NEPA analysis

DSEIS Section 4.13.5.2 includes almost nothing but general descriptions of standard spill response practices, as well as descriptions of general legal requirements, spilt up into the following sections:

- Section 1 – Notification Procedures
- Section 2 – Response Actions
- Section 3 – Response Teams
- Section 4 – Spill Impact Considerations

Notification

The notification procedures section is merely a summary of federal OPA notification requirements applicable to all crude oil pipelines. Although TransCanada has its own reporting procedures, control center, and command structure, so do all other oil pipeline operators, and all of them must comply with the same general OPA FRP requirements. Since the DSEIS does not discuss TransCanada's internal notification requirements in any detail, the descriptions included are entirely generic and provide no basis for critical analysis of TransCanada's specific KXL FRP changes required to comply with OPA notification standards.

The DSEIS reports extensively on a very simple information drill run by TransCanada for its Keystone System FRP that required notification in accordance with OPA regulatory requirements (there are no detailed requirements for notification procedures in PHMSA's PSA regulations). It is not clear if this drill was announced or unannounced. The DSEIS brags that the objectives of the drill were accomplished in 17 minutes, thereby implying that the pipeline would be shut down and all required parties notified within 17 minutes of a spill. This being said, an actual site inspection was not performed as part of the drill and neither was an actual shutdown. As made clear by the Line 6b spill, response delay results primarily from operator error, the length of time it takes to confirm a spill on-site, and the time it takes to mobilize sufficient response equipment and personnel, none of which were tested by this drill. The drill merely confirmed that TransCanada staff can read call lists, dial telephones, and send faxes.

Response Actions

This section is entirely generic and could apply to any pipeline and any pipeline operator. There is no project-specific information. Instead, the DSEIS states that response details would be included in a "Project-specific ERP to facilitate rapid response in the event of an oil release,"[419] which would be the OPA FRP, thereby confirming that the DSEIS itself contains no project-specific information.

Response Teams

This section also contains entirely generic information, to the extent that "Keystone" and the names of the pipelines referenced in the discussion could be changed to "Enbridge" and its pipelines and the DSEIS discussion would still be entirely applicable. Moreover, this section of the DSEIS refers extensively to PHMSA's OPA regulations in 49 C.F.R. Part 194 and recognizes that all project-specific information would be included in this document, thereby again confirming that there is only one spill response plan prepared by TransCanada and it is the OPA FRP. The DSEIS mistakenly asserts that the "Keystone ERP would be used as a template for the Keystone XL ERP," because the FRP for KXL would not be a separate document but instead would be a change to the existing Keystone Pipeline System FRP. Thus, the existing FRP would not serve as a "template" for a new document.

This discussion also references PHMSA's meaningless equipment requirement provision, 49 C.F.R. § 194.115, which specifies response times for equipment, but provides no standards for calculation of the amount of equipment required or calculation of the time required to transport the equipment to site. The DSEIS merely refers to "necessary resources."[420] Given the NTSB report's harsh criticism of this meaningless regulation, reliance on it provides no assurance that TransCanada will in fact have adequate response resources pre-positioned appropriately to mitigate the environmental impacts of a KXL rupture. Moreover, the DSEIS's acknowledgement that it contains no information about project-specific equipment and personnel means that it is impossible to comment meaningfully on TransCanada's actual ability to respond to a KXL oil spill.

The DSEIS does acknowledge that "worst case discharge" means more than merely calculating the amount of oil released, because it states that a worst case discharge analysis "consists of calculating and identifying where the WCD may potentially occur, plans to ensure that adequate personnel and equipment resources are available to respond, and scenario

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[419] DSEIS, at 4.13-71.
[420] SDEIS at 4.13-72.

development."[421] This being said, the DSEIS provides no estimate of the worst case discharge amount, the approximate locations of discharges, the amount of equipment and personnel required for such response, the potential geographic spread of a spill comprised of this amount of oil, or any project-specific scenario development. The DSEIS's discussion of geographic scope is entirely academic and includes no quantified estimate for how far and how fast an oil spill might spread in a worst case discharge scenario.[422] Given that both the U.S.C.G. and the U.S.E.P.A. provide methodologies for measuring such geographic impact,[423] the DSEIS should estimate this, as well.

The DSEIS discusses equipment only to the extent that it cut and pasted a generic equipment list that contains no quantification into DSEIS pages 4.13-72 and 73. Again, this generic equipment list identifies the types of equipment that all petroleum pipelines utilize in the event of a spill.

Sadly, the DSEIS Section 4.13 fails to discuss the Enbridge Line 6b spill in any detail and instead states in passive voice:

> When developing the ERP, Kalamazoo River Spill lessons learned would be considered, including ensuring consultants are contracted as appropriate to facilitate a large-scale and prompt response; developing source containment plans including strategies and tactics; minimizing response times with appropriate equipment; identifying equipment resources required to respond to sunken and submerged oil, and ensuring personnel are appropriately trained.

Merely stating that knowledge gained would be incorporated into the FRP is insufficient. The DSEIS must consider the specific lessons learned in its analysis of the KXL FRP and demonstrate how TransCanada is actually incorporating these lessons into the FRP. Absent such detail, it is impossible for commenters to determine if TransCanada and PHMSA have in fact learned any lessons and what these lessons might be.

Spill Response Considerations

This section is completely generic to the point that it could have been cut and pasted from an "oil spill 101" fact sheet. There is nothing in this section that allows meaningful comment on TransCanada's FRP.

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[421] SDEIS at 4.13-73.
[422] SDEIS at 4.13-19-20.
[423] The U.S.C.G. and U.S.E.P.A. oil spill distance calculations are found respectively at 33 C.F.R. § 154.1035(b)(4)(iii); 40 CFR Part 112 Appendix C §§ 1.5, 2.5, 2.6, 5.4.

B. The cherry-picked sections of TransCanada's mocked up "Emergency Response Plan" provide no meaningful basis for NEPA review of oil spill response planning for KXL

There appears to be no requirement in federal law for a spill response plan to remediate crude oil spills from KXL other than the OPA FRP. As such, the document submitted by TransCanada is not required by law and is not subject to approval by PHMSA pursuant to any formal statutory requirement. Since it is not the FRP required by the OPA, it cannot substitute for the FRP in a NEPA review of the FRP. This being said, we comment on this document for what it is worth.

Initially we note that the contents of the App. I ERP were selected based on the State Department Information Request 5.6.5, the text of which is included in TransCanada's response to the Information Request, which response is included in Appendix I as a cover sheet for the App. I ERP. The State Department information request states: "We understand that under current regulations, Keystone will not be required to <u>submit</u> an Emergency Response Plan (ERP) until 6months prior to Project operation." (Emphasis added.) We note that this statement assumes a completely different regulatory timeframe than stated at DSEIS page 4.13-68, which states: "PHMSA regulations require <u>approval</u> for an ERP for the proposed Project at least 6 months prior to beginning pipeline operation." (Emphasis added.) Thus, the DSEIS states that the App. I ERP must be <u>approved</u> at least six months prior to operation, whereas the Information Request states that the App. I ERP need not be <u>submitted</u> until 6 months before the start of operations. The State Department should actually review applicable federal regulations, determine what they say, and cite to them.

The State Department information request defines its purpose and scope as follows:

> Keystone should provide a draft ERP that reasonably describes the key procedures, coordination activities, anticipated contacts, equipment to be used, possible cleanup activities, and other information needed to understand how Keystone would respond to an accidental release of crude oil during operation of the Project. This draft could be developed using previously approved ERP's, such as the ERP for the Keystone Pipeline Project.

In response, TransCanada states:

> Attached are responsive portions of the Keystone Pipeline Emergency Response Plan. This plan will be updated to include Keystone XL-specific emergency preparedness and emergency response information prior to Keystone XL project commencing operations.

Thus, TransCanada has not provided a draft KXL plan, but rather portions of a <u>Keystone Pipeline</u> emergency response plan that TransCanada says will be updated to include Keystone

XL-specific information. This is confirmed by the fact that even though the App. I ERP has no title sheet explaining what it is, it is entitled "TransCanada-Keystone" (not "Keystone XL") in each footer. The State Department apparently found TransCanada's response acceptable, thereby essentially letting TransCanada determine the scope of spill response information that should be made available to the public.

This procedure is odd and inappropriate since PHMSA has in its files the current, complete, and formally approved OPA FRP for the Keystone Pipeline System, such that PHMSA has the ability and as a cooperating agency the legal responsibility to provide this information for the DSEIS. Although the existing OPA FRP is not by itself sufficient to allow meaningful comment, its disclosure is nonetheless necessary since TransCanada intends to update it to include planning for KXL. The State Department's deference to TransCanada and PHMSA's failure to provide information is also strange in light of the fact that PHMSA has previously disclosed, pursuant to Freedom of Information Act Requests, January 2009 and September 2009 versions of TransCanada's entire actual FRP ("January 2009 and September 2009 Keystone System FRPs"[424]),[425] the latter of which is only one year older than the document provided by TransCanada.

The State Department should explain why it relied on TransCanada to provide a document of dubious regulatory authority instead of requesting that PHMSA provide a formal plan approved by and in its possession. Moreover, the App. I ERP is dated September 2010 and was provided to the State Department on September 3, 2010, making it now over two and a half years old. As such, there is little wonder that the DSEIS Fails to apply the Enbridge Line 6b spill lessons learned, because the spill happened a little more than one month before TransCanada submitted the App. I ERP to the State Department. As such, that the App. I ERP could contain no "lessons learned" from this spill, because the lessons were not clear at that time. Now they are. Thus, TransCanada has provided no information indicating that the Line 6b spill has resulted in any changes in its spill response planning.

We note that TransCanada's response to the the State Department Information Request admits that the App. I ERP has no KXL-specific information in it and that this document applies exclusively to existing Keystone System pipelines. As such, it cannot serve as a basis for meaningful NEPA comment on the KXL FRP, any more than providing TransCanada's Application for a Presidential Permit for the first Keystone Pipeline would provide a basis for NEPA comment on its KXL Presidential Permit Application.

The App. I ERP includes the following sections:

- Section 1 – Notification Procedures
- Section 2 – Response Actions

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[424] Attached as Exhibits 101 and 102, respectively.

[425] Both of versions of the FRP specifically cite 49 C.F.R. Part 194 in Sections 1.2. As such, they are prepared and approved pursuant to OPA requirements.

- Section 3 – Response Teams
- Section 4 – Spill Impact Considerations
- Appendix A – Response Equipment/Resources
- Appendix B – Disposal Plan
- Appendix C – Basics of Oil Spill Response

Each of these sections is discussed in turn.

Section 1 – Notification Procedures

The notifications section includes a general set of internal and external notification protocols and lists of agency names and phone numbers for external notifications. It is generally similar to the notification sections in the January and September 2009 FRPs, but the internal notifications appear to have been changed to require that all reports of a spill go through the Keystone Oil Control Center (the system-wide controller for all Keystone System pipelines) rather than providing phone numbers for direct calls to spill contractors. The external communications section is similar, however, the App. I ERP omits contacts in North Dakota but includes them for Texas and Montana, which indicates (1) that TransCanada's spill response planning in 2010 included the Gulf Coast Segment and KXL such that it probably also long ago drafted an FRP for KXL; and (2) the possibility of conflicting requirements between plans if in fact TransCanada prepares multiple spill response plans for approval.

With regard to standardization, both the U.S.C.G. and U.S.E.P.A. require standardized FRP formats so that the EPA On-Scene Coordinator and other EPA staff can quickly access information regardless of the company or facility that provides it, as well as to ensure some uniformity of response requirements.[426] In contrast, PHMSA has only a recommended format contained in Appendix A to Part 194. Given the significant differences between TransCanada's prior FRPs and FRPs submitted by Enbridge, it appears that PHMSA leaves format largely to the discretion of the consultants who draft the plans for pipeline operators.

Section 2 – Response Actions

The information in this section is entirely generic and could be applied to any pipeline in the U.S. It appears to be boilerplate printed out by an oil spill consultant and therefore provides no assurance that TransCanada has thought about how to customize its current FRP for use along the KXL route. In fact, the word "Keystone" never appears in the text and the word "TransCanada" appears only twice as a general reference. There are no geographically specific response actions or any other project-specific details. The following are examples of the lack of specificity or inapplicability that characterizes this document:

[426] 33 C.F.R. § 154.1030; 40 C.F.R. Part 112, Subpart D, Appendix F.

- The “Earthquake Specific Response” section focuses almost entirely on workplace safety (*e.g.*, “If you are indoors, stay there. Do not run outside.”) and refers to pipelines only to the extent to say that they should be patrolled after an earthquake. There is no discussion about the complications to spill response that might result from an earthquake or how the relative risks of earthquakes in different segments of the route should impact spill response planning.
- The “Severe Winter Storm Specific Response” section is only about a quarter of a page comprising seven bullet points, all but two of which are related to paying attention to the weather. The pipeline specific bullet points include checking for storm damage and making any necessary repairs. The App. I ERP contains no discussion about the severe challenges of mobilizing resources, conducting outdoor spill response, or housing and feeding thousands of workers in the northern Great Plains in the winter, especially during blizzards.
- The App. I ERP includes a “Volcanic Eruptions Specific Response” section, even though the nearest “active” volcano is the ancient caldera at Yellowstone National Park approximately 300 miles from the closest point on KXL.[427] However, this volcano hasn’t erupted in approximately 640,000 years.
- The “Release to Groundwater Specific Response” does not mention any particular groundwater, such as the Ogallala Aquifer, or location-specific considerations related to groundwater.

Further, all of the brief oil containment, recovery, and disposal/waste management discussion is entirely generic and could be lifted from a general oil spill response training manual. There is no project information included.

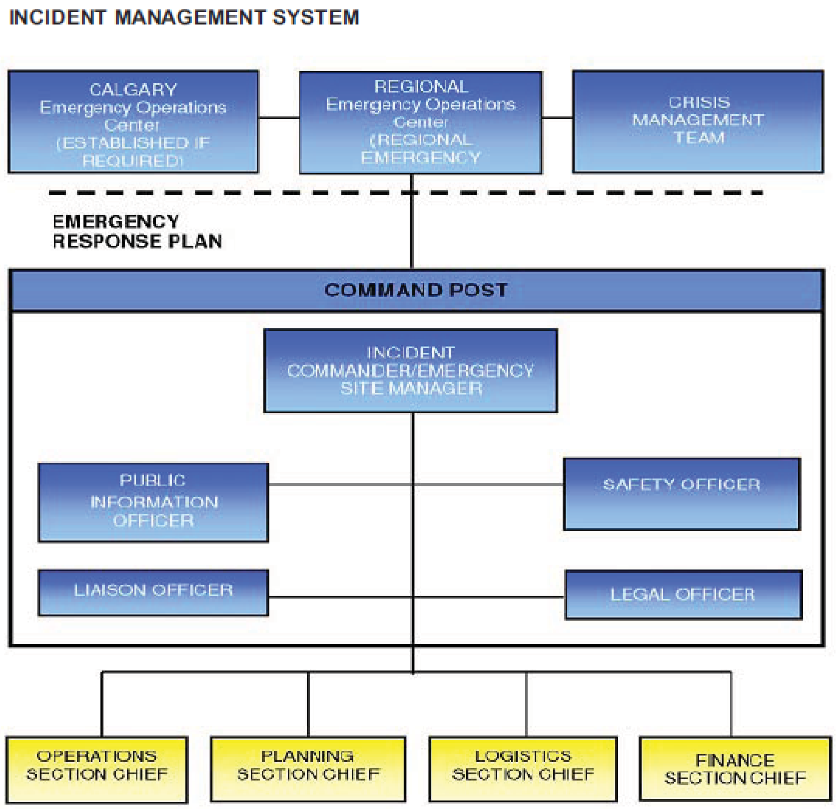
Thus, Section 2 of the App. I ERP contains nothing but a contractor-generated boilerplate that could be printed out for any pipeline in the U.S. As such, nothing in this section provides project-specific information on which substantive comments related to a spill response for KXL could be premised.

Section 3 – Response Teams

Section 3 is also almost entirely generic. It is comprised primarily of descriptions of management hierarchies and job descriptions, most of which do not appear to be specific to TransCanada and in fact may reflect an incident response hierarchy that a contractor would establish. Figure 3.1, below, includes the most comprehensive view of the App. I ERP’s description of command structures.

[427] http://www.nationalatlas.gov/dynamic/dyn_vol-us.html.

FIGURE 3.1
INCIDENT COMMAND SYSTEM



As can be seen, with the exception of the word "Calgary" in the upper left-hand box, the rest of the schematic could apply to nearly any incident command structure for any facility anywhere. The personnel job descriptions are also entirely generic and appear to be contractor boilerplate and include no project or geographically specific directions.

As a consequence of its generic nature, Section 3 provides no basis for meaningful comment on TransCanada's KXL OPA FRP or its project-specific plans.

Section 4 – Spill Impact Considerations

App. I ERP, Section 4 is entirely generic. It contains no statements specific to KXL or any other particular pipeline and no geographically specific information, but instead consists entirely of basic oil spill response information such as might be included in a beginning responder class. Because this section contains no project-specific information, it is impossible to comment on the merits of TransCanada's KXL FRP.

Appendix A – Response Equipment Resources

Appendix A contains some pipeline-specific equipment information for TransCanada's existing pipelines in the form of: (1) descriptions of TransCanada's self-owned equipment; and (2) the equipment owned by its spill response contractors. This information is similar to the information provided in the January and September 2009 FRPs and is only slightly newer. In fact, the Company Owned Equipment List in Figure A.1 appears to be identical to that found in the 2009 Keystone Pipeline System FRPs, and the identified spill response contractor is the same. Therefore, the analysis in the Great Plains at Risk Report continues to be accurate and should be addressed by the State Department. Only the major deficiencies in Appendix A are discussed here.

The App. I ERP states that TransCanada owns one trailer in each of its five response zones for its existing pipeline system.[428] The App. I ERP does not describe its response zones or state where these trailers are located, but the response zone definitions and the trailer location for just response zone 1 are provided by the 2009 Keystone System FRPs. The response zones are:

Zone	States	Trailer Locations
1	North Dakota, South Dakota, Nebraska	Yankton, SD
2	Kansas, Missouri, Illinois	?
3	Cushing Extension, Kansas, Oklahoma	?

The two other zones identified in the App. I ERP are likely Canadian Zones. Therefore, the App. I ERP does not include spill response commitments for KXL. In addition, TransCanada maintains one smaller trailer per response zone containing primarily oil spill boom. As detailed in the Great Plains at Risk report, for each response zone, the major equipment acquired by TransCanada includes: one response trailer, one boom trailer (together the trailers contain 2,000 feet of different types of boom), two boats, 298 bbls of temporary storage capacity, and two skimmers. TransCanada has not identified the locations of the tow vehicles for these trailer or related response personnel, even though the location of a tow vehicle and personnel at the time of a spill can significantly impact how quickly a trailer can arrive at a spill site.

The NTSB found that this amount of equipment was wholly inadequate to serve as the first waive (Tier I) resources for the Line 6b spill. This being said, Enbridge had far more equipment prepositioned than is planned by TransCanada, because Enbridge maintains spill response equipment at each of its pump stations as well as regional response trailers and equipment caches. In fact, since the Line 6b Spill happened close its Marshall Pump Station, Enbridge had its equipment close at hand, but it still proved to be entirely inadequate. Therefore, it appears that TransCanada has not learned any lessons from the Line 6b spill, or are not willing to share what they have learned.

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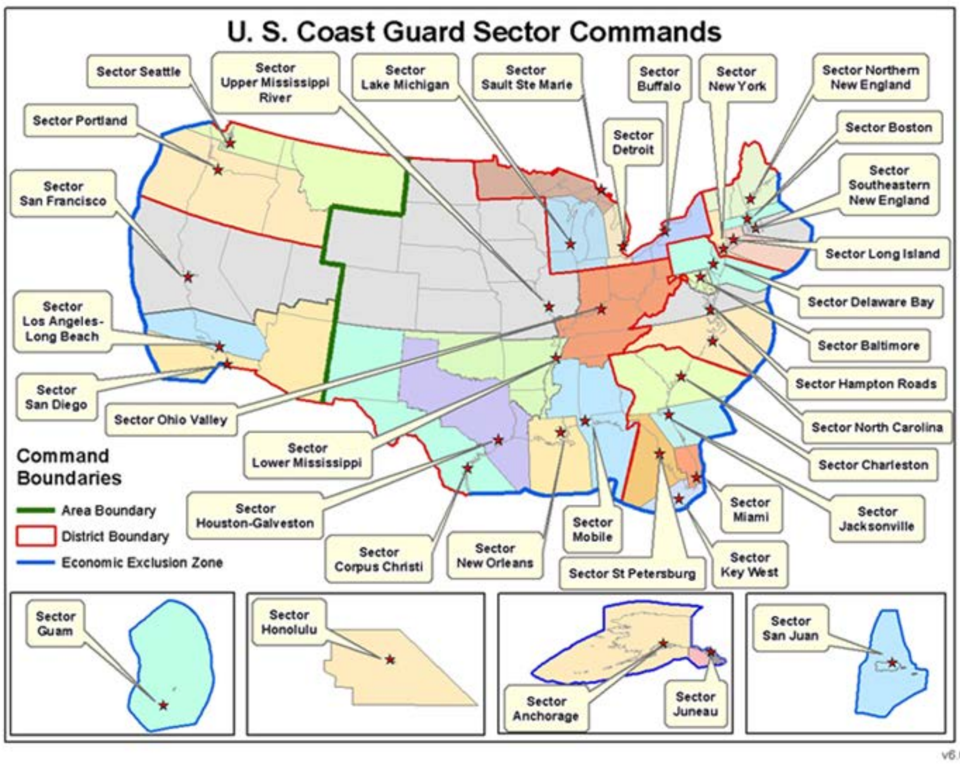
[428] App. I ERP App. A Figure A.1.

TransCanada's primary spill response contractor is National Response Corporation ("NRC"). The App. I ERP does not contain lists of response resources available to NRC. Instead, the App. I ERP includes Figure A.2 that shows NRC's U.S.C.G. Oil Spill Response Organizations ("OSRO") classification.[429] It claims to be certified for spills in all types of waters except the Great Lakes. Figure A.3 confirms that NRC's OSRO classification is determined by the U.S.C.G., and also shows the equipment that NRC claims to have and the time it would take it to transport this equipment to a spill from KXL. TransCanada assigns NRC's classification to each response zone, even though the USCG OSRO classification is not determined for each response zone, but rather is assigned to USCG Upper Mississippi River Sector as a whole(see map below), which includes all of the states through which KXL would pass.



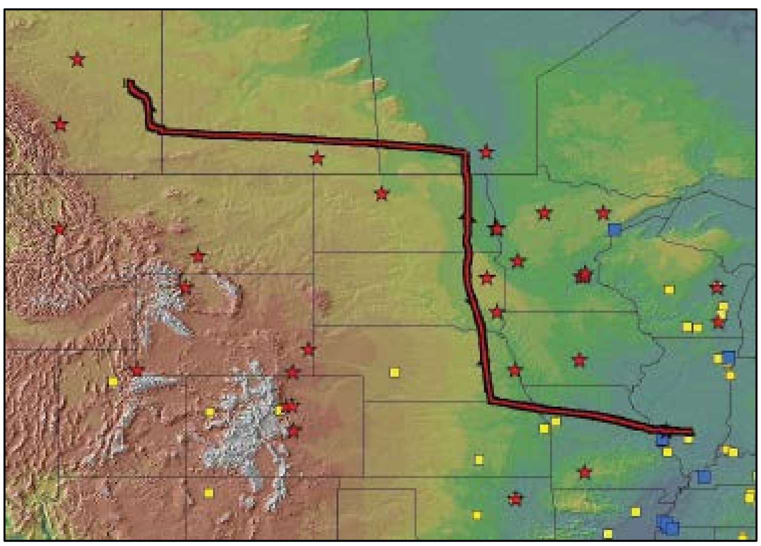
Given that TransCanada owns very little of its own spill response equipment, it appears to rely wholly on NRC's USCG OSRO classification for its spill response requirements. This reliance on NRC's classification is completely irrational.

U.S.C.G. OSRO classifications are based on the distance that the equipment is from a "Captain of the Port" city. The reason that the U.S.C.G. uses this metric is that it is primarily

[429] The introductory text for this Figure states: "The USCG has classified OSROs according to their response capabilities, within each Captain of the Port (COTP) zone, for vessels and for facilities in four types of environments."

concerned with spills from vessels, so it uses coastal port locations as proxies to determine how long it takes for equipment to reach a leaking vessel. For example, the Captain of the Port City for Sector Lake Michigan is Milwaukee. Spill response equipment located in Chicago would be given a mobilization time equal to the sailing time from Chicago to Milwaukee. Given that it is impossible to predict where an oil tanker might spill, this metric makes sense. But this metric makes no sense whatsoever when applied to a pipeline in Montana, South Dakota, or Nebraska. The Captain of the Port City for the Upper Mississippi River Sector is St. Louis. Thus, the U.S.C.G. rates NRC based on the distance that its equipment is from St. Louis. Thus, all that NRC has proven to the U.S.C.G. is that it can move a certain amount of equipment to St. Louis within the timeframes required by the U.S.C.G. to receive its OSRO rating. St. Louis is approximately 375 straight-line miles or 433 highway miles from Steele City, NE, the closest point on KXL's route. St. Louis is well over a thousand straight-line miles or 1,450 highway miles from KXL's proposed border crossing. It is absurd to think that a U.S.C.G. rating based on equipment deployment times to St. Louis is applicable to a crude oil spill in Montana.

App. I ERP Appendix A also provides a map (excerpt below) of the locations of equipment NRC owns as well as the locations of its subcontractors.



This map shows that NRC itself owns no equipment in Montana, South Dakota, or Nebraska, and that none of its subcontractors have locations anywhere near most of the KXL route. This lack of equipment in states along the KXL route is confirmed by the NRC website, which shows no NRC equipment in any of the KXL route states.[430] Since NRC primarily specializes in coastal cleanups, this is not surprising. It appears that NRC no longer lists its subcontractors on its website; however, the Great Plains at Risk Report shows that NRC had few subcontractors along

[430] http://www.nrcc.com/Services/Pages/Equipment.aspx

the KXL route as of 2009, and the NRC equipment map, above, indicates that it had fewer resources along the route in 2010 than it did in 2009.

Finally, the extent of NRC's preparation for an oil spill along the KXL proposed route is also called into question by the low cost of NRC's services. According to TransCanada's FERC Form No. 6: Annual Report of Oil Pipeline Companies and Supplemental Form 6-Q: Quarterly Financial Report (April 15, 2011)[431], in 2010, TransCanada paid NRC only $112,500 for its services. Since payments to spill response contractors are akin to insurance, this is very cheap insurance suggesting that TransCanada is not paying for much upfront investment by NRC. In contrast, TransCanada's Annual Form 6 for 2011 shows no payment to NRC greater than $100,000 (the lower limit for reporting).[432]

Although not listed in Appendix A, the App. I ERP identifies two additional spill response contractors, O'Brien's Response Management Inc. in Slidell, Louisiana, and ENSR Corporation in Fort Collins, CO. Since O'Brien's describes itself as a response management firm (for example, it drafted the App. I ERP), and ENSR is an environmental engineering firm, and because neither of these firms are identified as providing equipment, it is likely that TransCanada does not rely on their owned or contracted equipment to show compliance with federal law.

Thus, the App. I ERP contains no evidence that TransCanada or its spill response contractors have any significant amount of spill response equipment within hundreds of miles of the proposed KXL route. Moreover, this document's reliance on a U.S.C.G. oil spill response rating as proof that a company has adequate spill response resources in the northern Great Plains is a strong indication that TransCanada's oil spill response allegations are completely unfounded. Given that the DSEIS admits that nothing in the App. I ERP is project-specific to KXL, all of the DSEIS's assertions that TransCanada is prepared to respond to an oil spill simply have no meaningful evidentiary basis within the DSEIS. Moreover, this lack of information means that it is not possible to comment meaningfully on TransCanada's actual oil spill response capability, except to note that the limited evidence provided in the DSEIS indicates that TransCanada has little to no demonstrated response capability along the proposed KXL route.

Appendices B and C – Disposal Plan and Basics of Oil Spill Response

Both of these sections are completely generic and provide no project-specific information, such as actual locations of potential disposal sites or application of spill response

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[431] Attached as Exhibit 103.

[432] TransCanada 2011 FERC Form No. 6: Annual Report of Oil Pipeline Companies and Supplemental Form 6-Q: Quarterly Financial Report (April 15, 2011) at 351, detail at 604.1. TransCanada's 2012 annual Form 6 filing does not include any data for payments for services data. Therefore, it appears that that either FERC does not require or make public, or TransCanada no longer provides data, for page 351, Payments for Services Rendered by Other than Employees.

principles to locations along the proposed KXL route. Therefore, they provide no basis for meaningful comment on the OPA FRP.

iii. The DSEIS fails to consider critical spill response issues

As poor as the information in the DSEIS is, it also fails because it does not analyze critical oil spill response issues, including a number of issues highlighted by the NTSB Line 6b Report.

A. No analysis of site-specific spill response considerations

Success or failure of spill response is highly dependent on local conditions, yet the DSEIS's analysis of spill response fails to provide or discuss any site-specific information as it relates to spill response. This omission is critical because it does not allow comment on spill response planning for sensitive resources. Yet, TransCanada has available to it detailed maps, called "Environmental Sensitivities Maps," that it uses in its spill response planning. A list of these maps is included in Figure 6.2 of the 2009 Keystone System FRPs.[433] These maps show sensitive resources together with the pipeline and surrounding geographic features. Inclusion of these maps in the DSEIS would allow citizen comment and questions on TransCanada's specific spill response plans for areas of special concern.

B. No analysis of worst case discharge methodology, especially relative to remote spill detection management failures

As previously discussed, many oil spills from pipelines, including major spills such as the Line 6b spill, are not detected first through central control center analysis of SCADA data. Instead, spills are as likely to be detected by citizen reports to local authorities. As amply demonstrated by the Line 6b spill, pipeline operators do not always correctly interpret SCADA data with the result that a pipeline operator may continue pumping crude oil for a substantial amount of time after a rupture occurs. Yet, the DSEIS fails to consider the impact of SCADA system management failures on worst case discharges. PHMSA regulations require that KXL use the following methodology to determine the volume of a worst case discharge:

> The pipeline's maximum release time in hours, plus the maximum shutdown response time in hours (based on historic discharge data or in the absence of such historic data, the operator's best estimate), multiplied by the maximum flow rate expressed in barrels (cubic meters) per hour (based on the maximum daily capacity of the pipeline), plus the largest line drainage volume after shutdown of

[433] Commenters gained access to a limited set of these maps through a FOIA request, but they are not attached due to their size.

> the line section(s) in the response zone expressed in barrels (cubic meters).[434]

This regulation does not define the term "maximum release time." The 2009 Keystone Pipeline System FRPs describe TransCanada's methodology as follows:

> The Worst Case Discharge for this response zone was calculated electronically using elevation data, pipeline statistics, and designed operational levels. The first calculation completed was the volume released prior to the shutdown of the pipeline system. This volume is noted as "Pumping Rate Volume" and is equal to 8,740 barrels. Using the designed operational levels, the pumping rate volume is calculated by taking the pumping rate of 662,400 barrels per day and multiplying by the shutdown time of 19 minutes. The 19 minutes of shutdown time consists of 10 minutes of evaluation time, where the controllers decide that there is a problem and the line needs to be shut down, 9 minutes of pump station shutdown, which must be completed in a certain order to prevent damage to the system. To ensure that the volume is not underestimated, the 19 minutes of shutdown time is multiplied by the full pumping rate, 460 barrels per minute, even though, as pump stations are shut down the rate will decrease throughout the 9 minutes of shutdown.

Thus, TransCanada assumes 10 minutes of "evaluation time," during which operators determine there is a rupture, and 9 minutes of "shutdown time," during which operators turn off pumps.[435]

It is clear that TransCanada's methodology assumes no operator error or delay, such that its "evaluation time," which is the term it appears to use instead of "maximum release time," is not the "maximum" time but rather the expected time assuming no operator error or equipment malfunctions.

Due to the importance of the worst case discharge volume to spill response planning, the DEIS should analyze the "maximum release time" for KXL considering the possibility of operator error and equipment malfunctions.

C. No analysis of dilbit spill response capability

The NTSB Line 6b Report highlighted the difficulty and expense of removing submerged bitumen leftover after the lighter elements of the spilled dilbit had either evaporated and separated into or on the water column and/or for the bitumen to weather so as to become heavier

[434] 194.105(b)(1).

[435] 2009 Keystone Pipeline System FRPs, Appendix B, Worst Case Discharge Analysis and Scenarios, Response Capability Scenarios at 3, 7, 11, 19.

than water. Due to its failure to anticipate the tendency for the heavy components of dilbit to sink, the Enbridge Line 6b FRP completely failed to plan for removal of sunken oil even though the likelihood of this being necessary was undoubtedly known before the spill. The importance of planning for dilbit spills is one of the critical "lessons learned" from this spill.

Given the extensive nature of the DSEIS's analysis of the physical and chemical nature of dilbit found in Section 3.13, it is odd that the DSEIS failed to consider the impact of dilbit spills on spill response and cleanup activities in detail. Removal of sunken oil requires dredging, either using machinery or hand tools. In either case, such activities severely impact benthic habitats and displace large quantities of sediment into the water column. As noted by the EPA in its response to the Line 6b Spill, removal of submerged oil risks displacing toxic chemicals in aquatic superfund sites or other toxic waste accumulations. Since removal of submerged oil can have substantially more environmental impacts than removal of floating oil, the DSEIS must analyze these impacts.

Although the DSEIS identifies some of the impacts and challenges caused by submerged dilbit,[436] it fails to discuss or evaluate TransCanada's actual capacity to remove sunken oil. Instead it says:

> As the response to the Marshall Michigan Dilbit spill continues to mature and evolve, the lessons learned from the response and recovery efforts should be considered to facilitate the implementation of proper response planning and response strategies to improve the overall response to Dilbit spills."[437]
> When developing the ERP, Kalamazoo River Spill lessons learned would be considered, including ensuring consultants are contracted as appropriate to facilitate a large-scale and prompt response; developing source containment plans including strategies and tactics; minimizing response times with appropriate equipment; identifying equipment resources required to respond to sunken and submerged oil, and ensuring personnel are appropriately trained.[438]

Then the DSEIS makes the following general recommendations about future spill response planning:

> The emergency response plan and oil spill response plan should address a submerged oil as well as floating oil in a surface water release scenario. The USDOT Pipeline Response Plan should be reviewed in coordination with USEPA and include contingency plans to address a submerged oil response and cold weather

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[436] DSEIS, at 4.13-60.
[437] *Id.*
[438] *Id.* at 4-13.73.

> response. Section 4.13.5.2, Spill Response, focuses on a traditional oil spill response and not a strategy to address submerged oil or cold weather.
> Pre-positioned response assets should include equipment that could address submerged oil. Response strategies, such as pre-positioning of equipment to address submerged oil should be considered and may be fine-tuned with USEPA consultation.
> Spill drills and exercises should include strategies and equipment deployment to address floating and submerged oil.[439]

Since the OPA FRP must be reviewed under NEPA, the DSEIS may not simply make general statements about possible impacts and provide general recommendations for future action. Instead, it must analyze the impact of submerged oil spills on the types of aquatic habitats crossed by the proposed KXL route, the impacts of submerged oil response activities on the environment, and TransCanada's actual plans and capacity to remove submerged oil. The lessons have been learned from the Line 6B Spill, which happened almost three years ago, such that the DSEIS can no longer simply defer consideration of these lessons to some undetermined future date. Instead, it must incorporate the best current knowledge into its impact and mitigation analyses.

D. No analysis of spill response plans in sparsely populated areas and during all seasons

Most of the KXL's proposed route passes through sparsely populated areas. This fact has a number of substantial impacts on spill response, including: (1) a reduced likelihood of rapid citizen discovery of spills; and (2) an increase in logistical challenges related to housing and feeding the thousands of response personnel required for response to a major spill. Unlike the Line 6b Spill, which was located in and near densely populated cities and towns, most of the proposed route for KXL is sparsely populated, with the result that any response to a major spill would quickly overwhelm local infrastructure. The extremely small amounts of local infrastructure along the route is a critical limiting factor for spill response, especially during winter time. A spill response would require either establishment of work camps, as TransCanada intends to do during construction, or relying on very long commutes that would complicate deployment and decrease productivity. TransCanada has disclosed its planning for worker camps during construction, but provides no information about how it would house and feed oil spill response personnel and how long it would take to establish necessary infrastructure to do so. Unlike construction planning that can avoid winter and adverse spring and fall weather, a spill response must be implemented regardless of the season or weather. Therefore, the DSEIS should fully analyze TransCanada's plans, equipment, and resources needed to respond to a crude oil spill in sparsely populated areas in all seasons.

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[439] DSEIS, at 4.13-80.

E. No analysis of compliance with the National Contingency Plan or Area Contingency Plans

The OPA requires that the OPA FRP be consistent with the National Contingency Plan ("NCP") and applicable Area Contingency Plans ("ACP"), which for KXL include the Regions 7 and 8 ACPs. The DSEIS contains no discussion of the consistency of TransCanada's response planning with the NCP and Regions 7 and 8 ACPs. The App. I ERP provide no detailed discussion about TransCanada's efforts to ensure that its oil spill response planning is consistent with the NCP or the Regions 7 and 8 ACPs. Instead, it just states: "A thorough examination of published Area Contingency Plans (ACPs) was conducted to identify sensitive areas in all the response zones."[440] The App. I ERP also requires consultation of the applicable ACP as a spill <u>response</u> activity[441] and states that the TransCanada "may" consult the applicable ACP to determine "environmental/socio-economic sensitivities."[442] These references to environmentally sensitivity planning do not cover the full scope of the NCP and ACPs, and are too vague to demonstrate "consistency." Thus, the DSEIS contains no meaningful evidence demonstrating that TransCanada's spill response planning complies with the OPA through a showing consistency with the NCP and Regions 7 and 8 ACPs.

5 <u>The DSEIS Fails to Adequately Analyze Impacts in Canada</u>

a. NEPA Requires an Analysis of Trans-Boundary Impacts

The Council for Environmental Quality (CEQ) regulations explicitly state that an EIS must assess the cumulative impacts of the project when added to "all other past, present and reasonably foreseeable future actions regardless of what agency (Federal or non-Federal) or person undertakes such other actions." 40 C.F.R. §1508.7. A 1997 CEQ guidance clarifies that "NEPA law directs federal agencies to analyze the effects of proposed actions to the extent they are reasonably foreseeable consequences of the proposed action, *regardless of where those impacts might occur*."[443] CEQ concludes that "agencies must include analysis of *reasonably foreseeable transboundary effects* of proposed actions in their analysis of proposed actions in the United States."[444]

Courts have recognized the need to analyze trans-boundary impacts in an EIS. The Supreme Court has held that impacts must be analyzed when there is "'a reasonably close causal relationship' between the environmental effect and the alleged cause." *Department of Transportation v. Public Citizen*, 541 U.S. 752, 767 (2004). In *Gov't of the Province of Manitoba*

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[440] App. I ERP at 4-18.
[441] *Id*. at 2-7.
[442] *Id*. at 4-3.
[443] Council on Environmental Quality Guidance on NEPA Analyses for Transboundary Impacts, July 1, 1997, at ¶4, available at http://ceq.hss.doe.gov/nepa/regs/transguide.html
[444] *Id*. at ¶ 6 (emphasis added).

v. Salazar, 691 F. Supp. 2d 37, 51 (D.D.C. 2010), the court relied on the CEQ Guidance and held that the Defendants were required to consider the Canadian impacts of their U.S. water supply project. In *Border Power Plan Working Group v. Department of Energy*, 260 F.Supp.2d 997 (S.D. Calif. 2003) the court found Defendants were required to consider the trans-boundary impacts of certain power turbines in Mexico in their EIS on a U.S. transmission line. That was because the line was the only "current means" evidenced by the record through which the turbine could transmit its power, and the turbines and transmission lines were "two links in the same chain." *Id.* at 1017.[445]

b. The DSEIS Fails to Adequately Analyze Trans-Boundary Impacts

The DSEIS includes Section 4.15.4.3, "Environmental effects of oil sands development in Alberta," which mirrors the brief discussion of Canadian impacts contained in the 2011 Final EIS. The DSEIS includes some additional updates on some regional planning and basic science that has occurred since 2011. However, it remains inadequate, and lacks any objective, critical analysis of tar sands environmental impacts.

For instance, the U.S. State Department highlighted data from 2009 from the Alberta Biodiversity Monitoring Institute, which states the low level of development in the region. The State Department failed to include critical contextual information. This low level of impact for the entire region is what you would expect given that the oilsands are in the early stages of development — only four per cent of the reserve has been developed to date. Also, tarsands production and associated environmental impacts have increased over 30% since 2009. Even at this low level of cumulative disturbance, woodland caribou herds in the region are expected to go extinct within a few decades. Given that the Keystone Xl pipeline will require a 36% increase in tar sands development and operate for over 40 years, presenting historical data without including projected impacts will not provide decision makers with an accurate understanding of the environmental consequences of Keystone XL in Canada.

While the State Department relied on Government of Alberta information from 2010, the State Department failed to mention the following impacts from tar sands development:

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[445] Many other courts have held that NEPA requires analysis of impacts in foreign countries. See, e.g., *Sierra Club v. Adams*, 578 F.2d 389, 396 (D.C. Cir. 1978) (requiring an analysis of impacts to local Indian groups of a highway in Panama, and "assuming" NEPA is applicable to projects in Panama); *Nat'l Org. for Reform of Marijuana Laws (NORML) v. U.S. Dept. of State*, 452 F. Supp. 1226, 1233 (D.D.C. 1978) (applying NEPA to US participation in an herbicide-spraying program in Mexico); *Ctr. for Biological Diversity v. Nat'l Sci. Found.*, C 02-5065 JL, 2002 WL 31548073 (N.D. Cal. Oct. 30, 2002) (applying NEPA to an acoustic research program on the high seas); *Hirt v. Richardson*, 127 F. Supp. 2d 833 (W.D. Mich. 1999) (applying NEPA to a shipment of weapons-grade plutonium from New Mexico to Canadian border).

- Low-flow risks in the Athabasca River to due climate change and increased withdrawals from tar sands mines.[446] There is currently no protection for the Athabasca River if the tar sands industry wants to withdraw water during critical and increasingly common low-flow periods.
- Long-term toxicity risks from tailing ponds. The Government of Alberta has yet to effectively address the tremendous environmental and financial liabilities associated with tar sands tailings.[447]
- Inadequate reclamation liability management. The current scheme is overly risk tolerant to marginal economic tar sands production, leaving Alberta taxpayers underwriting billions of dollars of off-the-balance-sheet liabilities.[448]
- Even at current levels, let alone those required to fill Keystone XL, local woodland caribou populations are likely to go extinct within several decades.[449]
- Industry modeling confirms that expected cumulative environmental impacts of future tar sands will surpass legislated environmental thresholds. Despite this, the U.S. State Department analysis did not consider upstream cumulative effects of the Keystone XL pipeline.[450]
- Challenges associated with inadequate environmental monitoring were not mentioned despite it being a tool in determining appropriate tar sands production levels.[451]
- Contextual information on GHG emissions were absent, and no mention was made of the significant role that tar sands expansion will play in causing Alberta and Canada to miss their greenhouse gas emission targets.[452]
- Changes in federal and provincial environmental laws and permitting regime for pipelines and tar sands projects. Since the August 2011 FEIS, the most significant changes in Canadian environmental law in three decades occurred.[453]

The DSEIS also includes Section 4.15.4.4, "Protected Bird Species in Canada." This section is identical to the 26 August 2011 Final EIS. It fails to mention the impact of future tar sands development on protected bird populations. Research suggests that 6 to 166 million birds

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[446] Jennifer Grant, "New oilsands mine to go ahead despite lack of promised Athabasca River protection," Pembina Institute, 25 Mar 2013, http://www.pembina.org/blog/699
[447] Pembina Institute. 2013. Beneath the Surface: a review of key facts in the oilsands debate. Published January 28, 2013. http://www.pembina.org/pub/2404
[448] *Id.*
[449] Simon Dyer, "Federal recovery strategy confirms protecting habitat is key to protecting caribou," Pembina Institute, 15 Oct 2013, http://www.pembina.org/blog/651
[450] Pembina Institute, The case against the proposed Shell Jackpine oilsands mine expansion, 22 Oct 2013, http://www.pembina.org/pub/2378
[451] *See*, fn.447.
[452] Pembina Institute. 2013. The Climate Implications of the Proposed Keystone XL Oilsands Pipeline. Published January 17, 2013. http://www.pembina.org/pub/2407
[453] Jennifer Grant, "Weaker federal laws will increase pressure on Alberta to deliver on environmental management," 1 May 2012, Pembina Institute, http://www.pembina.org/blog/625

will be lost over the next 30 – 50 years from the direct impacts of tar sands development.[454] Despite the availability of quantitative data on avian mortality from tar sands operations, this information was not included in the largely qualitative State Department assessment.[455]

6. The DSEIS Failed to Adequately Analyze Impacts in Nebraska

The proposed reroute through Nebraska does not avoid the Sandhills, and like the first proposed route, it crosses the High Plains Aquifer, including the Ogallala Group. The proposed reroute poses significant threats to the natural resources of Nebraska. *See* Section II.C.2, discussing the numerous problems with Nebraska's re-route of the pipeline.

A pipeline spill would have major impacts on the aquifers that would be virtually immitigable. Despite TransCanada's claims that spill would be "localized", no studies have been conducted for a major or worse-case-scenario accident in the Ogallala aquifer. Whether a spill is major or "localized," it would greatly impact the drinking water of communities and landowners across the Nebraska.

The proposed reroute also crosses many areas of fragile soils in Northern Nebraska, including 94 miles of what NDEQ and TransCanada have defined as the Sandhills, which does not even include Keya Paha County and the Nebraska Entry Point. In fact, the previously denied route crossed 92 miles of the Sandhills.

Moreover, agricultural operations will be permanently damaged by the pipeline's construction, with the most drastic effects impacting irrigation systems and cattle grazing. Yet, there is no requirement that TransCanada compensate farmers and ranchers for economic damages, and TransCanada is not required to compensate landowners for damages to property resulting from future pipeline problems.

Finally, the local economy will not benefit as advertised by TransCanada, and independent research underscores this point. Few jobs will be brought to local communities. The steel used for the pipeline will not be locally sourced; instead, it will be imported from Wellspun, an Indian company. In addition, annual local property taxes on the pipeline will be at their highest value for the first full year of valuation. After that, tax revenues will depreciate over a seven-year period, leaving the pipeline untaxed and generating no revenue for the local economy for the remainder of the pipeline's operational life, which could be 40 years or more.

In sum, the new pipeline route through Nebraska puts significant natural resources at risk,

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[454] Pembina Institute, Natural Resources Defense Council, Boreal Songbird Initiative, Danger in the Nursery: impacts on birds of tar sands oil development in Canada's Boreal forest, 2 Dec 2008, http://www.pembina.org/pub/1760

[455] Kevin Timoney and Robert Ronconi, 2010, Annual bird mortality in the bitumen tailings ponds in Northeastern Alberta, Canada, Wilson Journal of Ornithology 122(3): 569-576 http://www.ceaa.gc.ca/050/documents_staticpost/59540/82534/Bird_Mortality.pdf

including water resources that the nation relies for food. In addition, the costs to communities of pipeline construction and operation will not result in any significant benefits to the local economy. Landowners have no mechanism for compensation from damages and the pipeline does not present significant permanent job opportunities to local Nebraskans. As such, the new Nebraska route must be rejected.

In addition, the DSEIS' evaluation of economic and social impacts to the State of Nebraska is inadequate. There is no consideration whatsoever of the social impacts of a pipeline on the residents of the area or the residents of the state at large. This is an incredibly divisive issue, which has resulted in alienation of neighbors in communities. It can result in feelings of powerlessness and hostility toward government due to a belief that government has turned its back on its own citizens in favor of a foreign pipeline company. There is no consideration of the need for mental health services in the aftermath of such a decision. These issues need to be considered in evaluating the social impacts of the pipeline.

There is also no economic evaluation other than the idea that it would generate economic benefit. There was no analysis of economic impacts from potential crop loss, only that TransCanada would provide compensation for such losses. The risk assessment is completely inadequate. There is no assessment of the impacts of a spill on Nebraska's agricultural economy.

There is no valid assessment of the economic risks to Nebraska's most cherished resources, in particular, the risks to the aquifer. University of Nebraska Lincoln agricultural economists are currently conducting studies that model the valuation of water in an aquifer. These values in conjunction with a risk assessment would provide a better economic analysis of this project. There is also no analysis of whether TransCanada's offer of a $200 million insurance policy is adequate, particularly in light of clean-up costs from the Enbridge pipeline spill in Michigan in 2010 that exceed $800 million.

7. <u>The DSEIS Does Not Adequately Analyze the Direct, Indirect, and Cumulative Impacts of All Connected Actions</u>

The State Department's analysis of the impacts of, and alternatives to, all connected actions fails to meet NEPA's hard look requirement.

a. NEPA Requires an Analysis of All Connected Actions in a Single EIS

NEPA requires connected actions "to be considered together in a single EIS." 40 CFR 1508.25(a)(1); *Thomas v. Peterson*, 753 F.2d 754 (9th Cir. 1985). Connected actions include "interdependent parts of a larger action and depend on the larger action for their justification." 40 C.F.R. § 1508.25(a)(1)(iii). "NEPA instructs that significant cumulative impacts are not to be made to appear insignificant by breaking a project down into small component parts." *Utahns for Better Transp.*, 305 F.3d at 1182, *as modified on reh'g*, 319 F.3d 1207 (10th Cir. 2003) (citing 40 C.F.R. §1508.27(b)(7)); *Pres. Endangered Areas of Cobb's History, Inc. v. U.S. Army Corps of Engineers*, 87 F.3d 1242, 1247 (11th Cir. 1996)(the Corps cannot avoid NEPA by artificially dividing a major federal action into smaller components, each without a 'significant' impact.")(citing *Coalition on Sensible Transportation, Inc. v. Dole,* 826 F.2d 60, 68 (D.C.Cir. 1987)). Most circuits apply an independent utility test "to determine whether multiple actions are so connected as to mandate consideration in a single EIS." *See, e.g., Wilderness Workshop v. U.S. Bureau of Land Management,* 531 F.3d 1220, 1228-31 (10th Cir. 2008).

Further, NEPA regulations specify what an agency must provide if it lacks information in an EIS:

> When an agency is evaluating reasonably foreseeable significant adverse effects on the human environment in an environmental impact statement and there is incomplete or unavailable information, the agency shall always make clear that such information is lacking.
>
> (a) If the incomplete information relevant to reasonably foreseeable significant adverse impacts is essential to a reasoned choice among alternatives and the overall costs of obtaining it are not exorbitant, the agency shall include the information in the environmental impact statement.
>
> (b) If the information relevant to reasonably foreseeable significant adverse impacts cannot be obtained because the overall costs of obtaining it are exorbitant or the means to obtain it are not known, the agency shall include within the environmental impact statement:
>
>> (1) A statement that such information is incomplete or unavailable; (2) a statement of the relevance of the incomplete or unavailable information to evaluating reasonably foreseeable significant adverse impacts on the human environment; (3) a summary of existing credible scientific evidence which is relevant to evaluating the reasonably foreseeable significant adverse impacts on the human environment, and (4) the agency's evaluation of such impacts based upon theoretical approaches or research methods generally accepted in the scientific community. For the purposes of this section, "reasonably foreseeable" includes impacts which have catastrophic consequences, even if their probability of occurrence is low, provided that the analysis of the impacts is supported by credible scientific evidence, is not based on pure conjecture, and is within the rule of reason.

40 C.F.R § 1502.22.

b. The DSEIS' Consideration of Connected Actions

The DSEIS identifies three connected actions: the Bakken Marketlink Project, the Big Bend to Witten 230-kilovolt (kV) electric transmission line, and electric distribution lines and substations associated with the proposed pump stations.

The Bakken Marketlink Project is proposed by Keystone Marketlink, LLC, a wholly owned subsidiary of TransCanada Pipelines Limited. The project would include the construction and operation of facilities near Baker, Montana, and in Cushing, Oklahoma, to transport domestically produced crude oils originating from the Bakken formation in Montana and North Dakota. The Bakken Marketlink Project's plans for Montana include a 5-mile pipeline, meter manifolds, booster pumps, two 250,000-barrel tanks[456] that would be used to accumulate crude from connecting third-party pipelines and terminals, and one 100,000-barrel tank that would be used for operational purposes. The Bakken Marketlink Project's plans for Oklahoma include booster pumps and two new storage tanks at the proposed Keystone XL Cushing tank farm. The Bakken Marketlink Project would allow up to 100,000 bpd of domestic crude oil to be uploaded onto the Keystone XL Pipeline, with commitments for the transport of 65,000 bpd already established.[457]

The Big Bend to Witten 230-kV Transmission Line is proposed by Basin Electric Power Cooperative to meet the power requirements for the proposed pump stations in South Dakota. The proposed project would include construction and operation of an approximately 76-mile long transmission line in south-central South Dakota, as well as a new substation (Lower Brule Substation) and expanded substation (Witten Substation). The transmission line would be constructed within a 125-foot-wide right of way. The DSEIS notes that the U.S. Department of Agriculture's Rural Utility Service (RUS) is responsible for NEPA compliance and is preparing an Environmental Assessment with scoping for the proposed Transmission Line Project.[458]

Multiple private power companies or cooperatives would construct/expand and operate the electrical distribution lines and substations needed to power the 20 pump stations along the Keystone XL Pipeline. The electrical distribution lines are estimated to total approximately 377 miles. The DSEIS notes that the local power providers would be responsible for obtaining the necessary permits, approvals, or authorizations from federal, state, and local governments.[459]

c. The DSEIS' Analysis of Connected Actions Violates NEPA

In violation of its responsibilities under NEPA, the State Department avoids meaningful analysis of the connected actions in the DSEIS by deferring to environmental reviews to be conducted by other agencies and/or stating that impacts of the connected action are likely to be similar to those of the proposed Keystone XL Project.

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[456] In Section 2.1.12, the DSEIS incorrectly states that the Bakken Marketlink Project would consist of "one 250,000-barrel tank…and a 100,000-barrel tank" (2.1-75) near Baker, Montana. However, Figure 2.1.12-1 shows **two** 250,000-barrel tanks and one 100,000-barrel tank. Furthermore, subsequent references to the Bakken Marketlink Project indicate that the project would include a total of **three** new storage tanks near Baker, Montana (*See* 3.1-24, 3.2-7, 3.5-33, 3.6-13, etc.).

[457] DSEIS, at 2.1-75.

[458] *Id.* at 2.1-77.

[459] *Id.* at 2.1-83.

The DSEIS acknowledges its own deficiencies, noting that "additional relevant information related to connected actions is pending and will be included in this review as part of the Final Supplemental EIS."[460] The DSEIS goes on to explain in Section 2.1.12:

> Preliminary information on the design, construction, and operation of these projects is presented below. Although the permit applications for these projects would be reviewed and acted on by other agencies, the potential impacts of these projects have been analyzed in the Supplemental EIS based on currently available information and are addressed within each resource assessed in Chapter 4, Environmental Consequences. However, in some cases only limited information was available on the design, construction, and operation of the projects. The reviews of permit applications by other agencies would include more detailed environmental reviews of the connected actions.[461]

However, an examination of the Environmental Consequences chapter in the DSEIS reveals that potential impacts of the connected actions have not been meaningfully analyzed. Instead, the State Department avoids performing a substantive assessment by referring to the potential impacts of the proposed pipeline in another section. For example, in the DSEIS section discussing Water Resources, the State Department makes the following conclusions for each of the connected actions:

> **Bakken Marketlink Project:** "the potential impacts associated with expansion of the pump station site to include the Bakken Marketlink Project facilities would likely be similar to those described above for the proposed Project pump station and pipeline ROW in that area."[462]
>
> **Big Bend to Witten 230-kV Transmission Line:** "Hydrogeologic conditions and fate and transport of releases would be similar to conditions described for alluvial aquifers in the proposed pipeline area."[463]
>
> **Electrical Distribution Lines and Substations:** "Hydrogeologic conditions and fate and transport of releases would be similar to conditions described for the proposed pipeline area adjacent to the planned transmission lines."[464]

This same conclusion is repeated nearly verbatim in the Soils, Cultural Resources, Fisheries, and Land Use sections of the DSEIS for the three connected actions. *See, e.g.*, Soils,

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[460] *Id.* fn. 6, at 2.1-75.
[461] *Id.* at 2.1-75.
[462] *Id.* at 4.2-23 to 24.
[463] *Id.* at 4.2-24.
[464] *Id.*

4.2-11; Water Resources, 4.3-23 and 24; Fisheries, 4.7-14; Land Use, Recreation, and Visual Resources, 4.9-12; Cultural Resources, 4.11-15 and 16. This is an inadequate analysis of the direct and indirect impacts of connected actions and thus, does not comply with NEPA.

A reading of the DSEIS analysis of Cumulative Impacts by Resource in Section 4.15.3 also reveals a lack of substantive analysis. Each subsection contains the following statement, repeated verbatim except for the resource referenced:

> Impacts to [resource] from the construction and operation of the connected actions (Bakken Marketlink Project, Big Bend to Witten 230-kV Transmission Line, and Electrical Distribution Lines and Substations) are not substantially different from the proposed Project.[465]

Further, a look at the Summary of Potential Impacts in Table 4.16-1 also indicates that a thorough analysis of connected actions was not undertaken. Nearly every entry under the heading, Connected Actions, describes impacts relative to those of the proposed Project. This determination enables the DSEIS to overlook the project-specific environmental impacts from connected actions, as well as the additive effects of impacts from connected actions alongside impacts from the proposed pipeline. To fulfill its NEPA responsibilities, the State Department must perform a thorough, independent analysis of environmental impacts from connected actions without simply referring to potential impacts from the proposed Project.

The State Department also attempts to shirk its duties under NEPA by deferring to the "more detailed environmental reviews of the connected actions" to be conducted by other federal and state agencies. However, as aforementioned, all connected actions must be considered together in a single EIS. Most importantly, there is no indication that many of these connected actions, such the nearly 400 miles of power lines that would be permitted by local power providers, would undergo any further NEPA analysis. These power lines have the potential to impact endangered species such as the Whooping crane. The impacts of these connected actions must be analyzed now by the State Department, before there is an irretrievable commitment of agency resources.

The DSEIS analysis of the land use, recreation, and visual resources impacts of the Bakken Marketlink Project contains the following passage:

> The permit applications for this project would be reviewed and acted on by other agencies. Those agencies would conduct more detailed environmental reviews of the Bakken Marketlink project. Potential impacts to land use, recreation, or visual resources of the

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[465] *See*, Geology, 4.15-31; Soil, 4.15-33; Water Resources, 4.15-38; Wetlands, 4.15-42; Terrestrial Vegetation, 4.15-44; Wildlife, 4.15-47; Fisheries, 4.15-51; Land Use, Recreation, and Visual Resources, 4.15-61; Socioeconomics, 4.15-65; Cultural Resources, 4.15-67; Air Quality and Noise, 4.15-69.

> Bakken Marketlink project would be evaluated and avoided, minimized, or mitigated in accordance with applicable regulations during the environmental reviews for these projects.[466]

The DSEIS similarly invokes other agencies in its discussion of potential impacts from connected actions in Wetlands, 4.4-14 and 15; Fisheries, 4.7-14; Threatened and Endangered Species and Species of Conservation Concern, 4.8-35; Cultural Resources, 4.11-15 and 16; Air Quality and Noise, 4.12-22. The State Department must take a hard look at the project, including all connected actions, before the project is issued a Presidential Permit. The agency cannot avoid its legal obligations by merely claiming connected action impacts will be analyzed by other agencies granting a future permit, or by claiming connected actions will comply with applicable mitigation measures and regulations.

A meaningful analysis of alternatives to the connected actions is also evaded in the DSEIS. The State Department must analyze various alternatives and the alternatives' potential impacts. Again, the agency defers to environmental reviews that will be conducted in the future: "An additional and separate NEPA environmental review of the alternatives to the proposed transmission line would be conducted after the alternative routes are further defined."[467] Furthermore, the DSEIS concludes that the impacts of the connected actions "would be essentially the same as the proposed Project," and therefore, are not further evaluated in the alternatives analysis.[468] This is a plain violation of the State Department's responsibilities to assess alternatives to the connected actions themselves.

> If a draft statement is so inadequate as to preclude meaningful analysis, the agency shall prepare and circulate a revised draft of the appropriate portion. The agency shall make every effort to disclose and discuss at appropriate points in the draft statement all major points of view on the environmental impacts of the alternatives including the proposed action.[469]

The DSEIS also fails to examine the impacts of increased shale oil extraction in Montana and North Dakota, which would be enabled by the Bakken Marketlink Project. The rapid development of U.S. tight oil has resulted in a growing demand for transportation capacity out of the Bakken formation area. As the Market Analysis section of the DSEIS notes, this transportation demand has been mostly met by rail. Adding pipeline transport capacity through the Bakken Marketlink Project would allow for further development of the Bakken formation. The direct, indirect, and cumulative impacts of this accelerated development in Montana and North Dakota must be addressed. This includes, but is not limited to, an increase in the use of

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[466] DSEIS, at 4.9-12.
[467] DSEIS, at 2.1-78.
[468] *Id.* at 5.2-2.
[469] 40 C.F.R. § 1502.9

hydraulic fracturing, increases in GHG emissions, and its displacement of alternative fuels and renewable energy development and sales.

The State Department should use the information provided in its Market Analysis, in addition to other authoritative sources, to assess whether there is a purpose and need for the Bakken Marketlink Project. According to Table 1.4-8 in the DSEIS, there will be a total capacity of 1,235,000 bpd in rail off-loading projects providing access to Gulf Coast refineries by 2015.[470] The U.S. Energy Information Administration's Early Release of the Annual Energy Outlook 2013 predicts that U.S. tight oil production will decline after 2020, resulting in flattening of production after 2030.[471] The State Department should evaluate whether current and foreseeable rail transport capacity will accommodate projected production volumes from the Bakken. The rail alternative must be considered for the Bakken Marketlink Project, in addition to the larger Keystone XL Pipeline Project.

Finally, the State Department must analyze and inform the public as to how the additional sources of conventional crude oil will interact with the tar sands crude oil being transported from Alberta, and whether any operational or design changes will be necessary. For example, the agency should examine whether the currently-planned pumping stations will be sufficient to accommodate the additional sources and additional capacity; whether the different chemical composition of oil from the Bakken project shippers will present different threats and impacts in the event of a leak or rupture; whether the amount of diluent or heating that is required to move the crude through the pipeline will change; what additional facilities, operational plans, or emergency response plans will be necessary.

d. The DSEIS Fails to Analyze the Gulf Coast Pipeline as a Connected Action

The State Department violated NEPA by failing to consider the entire Keystone XL Pipeline between the U.S.-Canada border and the Gulf Coast in a single EIS. TransCanada previously proposed Keystone XL to transport 830,000 bpd of tar sands crude oil 1,384-miles from Alberta, Canada, to the Texas Gulf Coast. TransCanada repeatedly stated that it would not be economically feasible to break the project into multiple parts. For example, an Information Request in an NEB proceeding asked:

> *Could the first phase of Keystone XL, the Gulf Coast Segment, proceed without the other? What circumstances could warrant that scenario?*

TransCanada responded:

[470] DSEIS, at 1.4-34.
[471] U.S. Energy Information Administration, *Annual Energy Outlook 2013 Early Release Overview*, at 10, available at http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2013).pdf.

(No, there are no circumstances under which the first phase of the Keystone XL Pipeline, the Gulf Coast Segment, could proceed without the other, the Steele City Segment. Keystone would not be able to fulfill its contractual obligations to provide transportation service under the Keystone XL Pipeline TSAs from Hardisty to the USGC unless all phases of the Keystone XL Pipeline are completed. Keystone would not proceed to construct solely the first phase of the Keystone XL, the Gulf Coast Segment, except as an initial construction phase of the complete Keystone XL Pipeline.[472]

However, following the January 2012 denial of its Presidential Permit, TransCanada notified the State Department that it could separate the KXL project into two parts, reapply for a Presidential Permit for the northern section, and proceed with the southern segment as a stand-alone project. TransCanada claimed that the southern portion, which it now calls the Gulf Coast Pipeline, has independent utility. The Gulf Coast Pipeline did not undergo any project-specific NEPA analysis before commencing with construction in 2012.

By failing to consider both sections of Keystone XL in a single EIS, the State Department has artificially and improperly segmented the project into smaller parts so as to avoid a full evaluation of its impacts. *Utahns for Better Transp.,* 305 F.3d at 1182, *as modified on reh'g,* 319 F.3d 1207 (10th Cir. 2003) (citing 40 C.F.R. §1508.27(b)(7)); *Pres. Endangered Areas of Cobb's History, Inc. v. U.S. Army Corps of Engineers*, 87 F.3d 1242, 1247 (11th Cir. 1996)(the Corps cannot avoid NEPA by artificially dividing a major federal action into smaller components, each without a 'significant' impact.")(citing *Coalition on Sensible Transportation, Inc. v. Dole*, 826 F.2d 60, 68 (D.C.Cir. 1987)).

The Gulf Coast Pipeline and the Keystone XL pipeline are connected actions. They are literally connected to each other; they were originally proposed as a single project, and while the Gulf Coast Pipeline may have some degree of independent utility in terms of capacity, its full capacity of 830,000 barrels per day can only be met by the construction of the Keystone XL Pipeline, also with a capacity of 830,000 bpd.

Furthermore, improper segmentation occurs where the "completion of the first project may cause the benefit/cost ratio on the second to rise sharply." *Coalition on Sensible Transportation, Inc. v. Dole*, 826 F.2d 60, 70 (D.C. Cir. 1987). The completion (or imminent completion) of the Gulf Coast Pipeline would cause the benefit/cost ratio on Keystone XL to rise sharply. Therefore, the two projects are connected actions that must be considered in a single EIS.

[472] TransCanada Response to Enbridge Information Request No. 1.22, NEB Ref. No. A1K5T6.

8. <u>The DSEIS Fails To Adequately Analyze The Air and Water Quality Impacts of Refining The Project's Crude Oil</u>

The DSEIS, like the EIS before it, fails to properly analyze and disclose the impacts that the project will have on air and water quality due to the refining of Western Canadian Sedimentary Basin ("WCSB") tar sands and other crudes in receiving refineries. The project will supply 600,000 to 830,000 barrels per day ("bpd") of WCSB tar sands to Petroleum Administration for Defense District ("PADD") 3 refineries in the Gulf Coast region. DSEIS at 4.15-72. It will also supply up to 155,000 bpd of crude to PADD 2 refineries in the Midwest. DSEIS at 4.15-71. Yet the DSEIS makes the perplexing claim that these supplies to refineries will not cause any adverse air quality impacts, and it fails to analyze water quality impacts at refineries at all.

As an initial matter, the DSEIS improperly classifies the impacts from refining of project crude as cumulative impacts, discussing them in Section 4.15, "Cumulative Effects Assessment." However, the air quality impacts from the refining of crude transported by the project are indirect impacts of the project, not cumulative impacts. Indirect impacts are "reasonably foreseeable" impacts "caused by the action" that "are later in time or farther removed in distance." 40 C.F.R. § 1508.8(b). On the other hand, a cumulative impact is "the incremental impact of the action when added to *other* past, present, and reasonably foreseeable future actions." 40 C.F.R. § 1508.7 (emphasis added). Here, the air and water quality impacts from refining of project crude, including any induced refinery expansions, are caused by *this* project, not other projects. Thus, the DSEIS should fully analyze these impacts as indirect effects of the project, not as cumulative impacts.

The DSEIS's analysis of air quality impacts due to the refining of project crudes is entirely inadequate. The DSEIS claims that there will be "little, if any" refinery air quality impacts because the quantity and quality of crude delivered to the refineries will not change. As described below, both of these assumptions are flawed. The DSEIS also presents flawed emissions estimates extrapolated from the proposed Hyperion refinery and the recently-completed Motiva refinery expansion, and improperly relies on Clean Air Act permitting as mitigation. Furthermore, the DSEIS fails entirely to evaluate the risk of accidental releases at receiving refineries, which will increase due to the corrosive nature of tar sands crude. Finally, the DSEIR does not contain any analysis of whether refining tar sands crude will adversely affect the wastewater produced by refineries.

a. The DSEIS Fails to Properly Analyze Whether the Processing of Additional Crude Oil at Receiving Refineries Will Cause Negative Air Quality Impacts

Based on the market analysis, the DSEIS assumes that the project will not increase the *quantity* of crude being refined by inducing refinery expansions or the construction of new refineries. DSEIS at 4.15-75. However, as there are no conditions on the Project requiring a crude substitution at existing refineries, it is unreasonable to rule that out as a possibility. The DSEIS admits that under that scenario, the project would increase air pollutant emissions. DSEIS at 4.15-71. Thus, the DSEIS must fully analyze the impact any increases in refining capacity at PADD 2 and 3 refineries will have on surrounding air quality.

b. The DSEIS Fails to Properly Analyze Whether the Change in Quality of Crude Being Processed at Receiving Refineries Will Cause Negative Air Quality Impacts

Even assuming it is true that the project would not increase the quantity of crude being processed at U.S. refineries, the project would still have significant air quality impacts in the areas near existing refineries. The DSEIS states that the "current supply of heavy crude oil delivered to PADD 3 from current overseas sources is either declining or at risk for political reasons." DSEIS at 4.15-77. In the absence of this heavy crude, and due to the influx of domestic light sweet crudes, refineries may switch to processing lighter crudes. In fact, some refineries in the Gulf Coast are already retooling to be able to process more light sweet crudes from Eagle Ford. Because refineries may actually process more light sweet crudes in the absence of the Project, the DSEIS must not simply assume that the tar sands that would flow through Keystone XL would be replacing other heavy, sour crudes. To the extent that the project crude will be replacing lighter crudes, the DSEIS must analyze the emissions that would not otherwise occur at those refineries.

Furthermore, the project will have significant air quality impacts even if the project crude replaces other heavy crudes. Tar sands diluted bitumen is different from conventional crudes—and even from other heavy Venezuelan and Mexican crudes—that are currently being processed at these refineries in a number of ways, which are described below. *See* Air Quality Impacts of the Keystone XL Project at Refineries in PADD 3 ("Fox Report")[473] at 6-7. In fact, the DSEIS implicitly admits that the crude carried by the project differs from other types of heavy crude by conducting a separate analysis of whether transporting WCSB dilbit poses any additional spill or leak risks. *See* DSEIS at 3.13-3 and Table 3.13-2. However, the DSEIS fails entirely to compare the air quality effects of switching from the current slate of crude or a likely future slate of crude to the crude supplied by the project.

The DSEIS, assuming that the tar sands that would flow through Keystone XL would replace heavy sour crude from Mexico and Venezuela, claims that the API gravity and average sulfur content of the crude oil slate would be the same with or without the project, and thus that there will be no adverse air quality impacts. DSEIS at 4.15-75. However, these sorts of "gross" data are insufficient to estimate the air quality impacts of the project. Fox Report at 9, 18-19. The DSEIS claims that changes in overall sulfur content are not correlated with emissions of sulfur oxides. DSEIS at 4.15-6. But merely comparing average sulfur content is not a proper method of estimating emissions. According to Dr. Phyllis Fox, a preeminent expert on refinery emissions, "sulfur is not simply sulfur, but is made up of a complex collection of individual chemical compounds such as hydrogen sulfide, mercaptans, thiophene, benzothiophene, methyl sulfonic

[473] *See*, Appendix II: Phyllis Fox, Air Quality Impacts of the Keystone XL Project at Refineries in PADD 3 (April 22, 2013).

acid, dimethyl sulfone, thiacyclohexane, etc. Each crude has a different suite of individual sulfur chemicals. The impacts of ‘sulfur’ depend upon the specific sulfur chemicals and their relative concentrations, not on the ‘gross’ amount of total sulfur. The fact that the total sulfur content of the crude slate is the same is irrelevant.” Fox Report at 9.

The only comparison of more detailed chemical properties of tar sands crudes with other crudes is in Table 3.13-2, which does not contain the information necessary to evaluate the potential air quality impacts. Fox Report at 9, 18-19; *see* DSEIS at Tale 3.13-2 (showing numerous gaps for various characterization data). The table omits many important constituents, such as trace metals, nitrogen, benzene, toluene, ethylbenzene, and xylenes. Fox Report at 8. In short, the DSEIS is missing the essential information about both the current and projected future crude slates at receiving refineries necessary to evaluate the impacts of the project.

In fact, heavy tar sands crudes have different physical and chemical properties than the conventional crudes currently being refined in PADD 3. Fox Report at 18-19. According to Dr. Fox, tar sands bitumen “contains 102 times more copper, 21 times more vanadium, 11 times more sulfur, six times more nitrogen, 11 times more nickel, and 5 times more lead than conventional heavy crude oil.” Fox Report at 19; *see also* DSEIS at 3.13-2. These pollutants can cause acid rain, bioaccumulation of toxic chemicals in the food chain, the formation of ground-level ozone and smog, visibility impairment, and odor impacts. Fox Report at 19.

The project will also cause more emissions because tar sands diluted bitumen requires more energy to refine. Fox Report at 1, 19, 21. Thus, to produce the same products, more fuel must be burned at fired sources at refineries and at offsite electric generating units. Fox Report at 1, 19, 21. For example, diluted bitumen requires more heat for distillation in the crude unit. Fox Report at 21. It also contains higher concentrations of catalyst contaminants than typical heavy crudes, which require more energy to remove. Fox Report at 22-24. It is hydrogen-deficient compared to conventional crude and thus requires substantial hydrogen production and addition during refining, which again requires more energy. Fox Report at 24. Diluted bitumen will also require additional coking capacity. Fox Report at 24-26. All of these characteristics of diluted bitumen increase energy demand, which will in turn increase combustion emissions, including those from heaters and boilers. Fox Report at 26. The DSEIS fails entirely to analyze this impact of the project, which will lead to increased criteria air pollutants and hazardous air pollutants. Fox Report at 1.

Any increase in ozone precursors is especially worrying because eight of the 15 PADD 3 refineries with direct pipeline access to the project are in ozone nonattainment areas. Fox Report at 17, Ex. B. Two other refineries in Louisiana with indirect access to the project crude are also in ozone nonattainment zones. Fox Report at 17, Ex. B. Thus, the increase in ozone precursors will contribute to existing violations of the NAAQS ozone standard in these areas. The DSEIS fails entirely to discuss this significant impact of the project.

The DSEIS must also analyze the increased air pollution caused by the diluents that will be used in the crudes transported by the project. To decrease the viscosity of tar sands bitumen so that it can travel via pipeline, it must be mixed with high levels of diluent, which itself can have air quality impacts. Fox Report at 1. The DSEIS fails to disclose the composition of the specific diluents that will be used in project-delivered crude. As a general matter, diluent contains high levels of volatile organic compounds ("VOCs"), sulfur compounds, and hazardous air pollutants, such as benzene, toluene, ethylbenzene, and xylenes. Fox Report at 12-13. Diluent also contains high concentrations of volatile mercaptans, which are highly odiferous and toxic. Fox Report at 14. These pollutants may be released into the air as they evaporate from tanks and as fugitive equipment leaks at refineries. Fox Report at 14. The DSEIS fails to acknowledge—let alone analyze—the increase in VOCs and hazardous air pollutants that the project will cause at refineries that will process tar sands. Again, an increase in VOCs, which are ozone precursors, is especially worrying because many of the receiving refineries are in ozone nonattainment zones. Fox Report at 17, Ex. B.

In sum, the project, even if it just replaces conventional heavy crudes from other sources, will adversely impact air quality in the areas surrounding the refineries. Compared to many conventional heavy crudes, tar sands bitumen is heavier and dirtier, will require more energy to refine, and will contain more diluent if shipped via pipeline. The State Department must analyze all of these impacts of the project, and model the estimated increases in air pollution in areas near receiving refineries.

c. The DSEIS' Reliance on Estimates of Emissions for the Motiva Refinery Expansion and the Proposed Hyperion Refinery to Estimate the Project's Impacts Is Flawed

Instead of containing a robust analysis of the air quality impacts the project will surely have, the DSEIS, for "illustrative purposes," presents a brief summary of the estimated emissions for the proposed Hyperion refinery expansion in PADD 2. DSEIS at 4.15-77. The DSEIS also claims that the emissions from the Motiva expansion in PADD 3 are similar to those from the proposed Hyperion expansion. *Id*. As an initial matter, the DSEIS's calculations contain a mathematical error or were calculated using an undisclosed procedure that is not obvious from the context. Fox Report at 28-29, Ex. C. The calculations should be revised or further explained. Furthermore, the DSEIS does not include the information about these expansions in the text or in appendices, thus depriving the public of essential information.

The DSEIS fails to explain why the emissions from the Hyperion or Motiva refineries are representative of emissions caused by an expansion of capacity to refine tar sands crude in PADD 3 refineries. The Motiva refinery expansion was not designed specifically to process tar sands and is thus not necessarily a good predictor of the impacts of the project. More important, both the Motiva expansion and proposed Hyperion refinery were categorized as new facilities, and are thus subject to strict emissions controls. Fox Report at 29-30. The DSEIS assumes that the PADD 3 refineries receiving the WCSB crude would be similarly "upgraded" and "use modern technology," DSEIS at 4.15-77, yet it fails to explain what those terms mean. In fact, many PADD 3 refineries are outdated and do not have current emission controls or updated metallurgy. Fox Report at 29.

Furthermore, the emissions derived from the Hyperion and Motiva expansions permitting process are not the actual emissions that are (or will be) occurring at those refineries. Instead, these estimates are the results of a netting analysis, in which reductions due to shutdowns of other existing units were used to offset increases. Fox Report at 31. Furthermore, the method used to estimate VOC emissions for permitting are outdated and notoriously inaccurate. Fox Report at 14-17. Thus, they are inappropriate to use as estimates for the project's impacts. The DSEIS should use real emissions measurements, not permitting estimates, to estimate the project's impacts.

Even assuming that the emissions from the proposed Hyperion refinery are representative of the emissions the project will cause, the DSEIS's analysis is patently inadequate. The annual emissions, which the DSEIS presents in one sentence with no additional detail, are quite large: up to 1,604 tons of nitrogen oxides, 4,148 tons of carbon monoxide, 4,290 tons of sulfur dioxide, 2,170 tons of particulate matter, and 1,718 tons of VOCs. DSEIS at 4.15-78. As described in previous comments, refineries in the Port Arthur and Houston areas are the most likely to receive tar sands crude from the project. Yet the DSEIS make no attempt to analyze what these increases will mean on the ground in these areas. This analysis is especially important for criteria pollutant nonattainment areas, such as Houston, which are already burdened by significant amounts of air pollution. Nor does the DSEIS attempt to estimate the increases in hazardous air pollutants that the project will cause in refinery areas. Instead, it circles back to its flawed assumption that the project will not cause any increase in air pollution because the crude transported by the project would be replacing or displacing crude from other sources. DSEIS at 4.15-78. The DSEIS must thoroughly investigate, analyze, and model the pollution that will occur in specific areas receiving project crude rather than rely on a back-of-the-envelope estimates that provide a single number for project emissions.

d. The DSEIS Continues to Improperly Claim that the Project's Air Quality Impacts Will Be Mitigated by Clean Air Act Permitting

The State Department continues to claim that it need not evaluate the air quality impacts of the project because all refineries are subject to the controls of the Clean Air Act. DSEIS at 4.15-74. Under that logic, no project subject to the Clean Air Act would ever have air quality impacts. To the contrary, a statement that a project will be subject to permitting under other statutes cannot substitute for analysis of environmental impacts under NEPA.

As a factual matter, permitting will not prevent significant air quality impacts. The air permitting processes in the Gulf States, especially Texas and Louisiana, are ineffective in controlling air pollution because applicants are often able to avoid triggering permitting in the first place though bogus netting analyses ("flex" permitting), piecemealing of projects, failure to disclose debottlenecking emission increases, and the use of invalid or outdated emission offsets. Fox Report at 3. Recent and pending refinery changes to accommodate these new tar sands crudes have been treated by Texas as minor modifications or minor amendments to flex permits and have not required any evaluation of air quality impacts. Fox Report at 4.

Furthermore, to the extent that the refineries receiving project crude are under consent decrees, those settlements do not reflect the highest level of pollution control required under the Clean Air Act. Fox Report at 4-5. For example, the consent decrees for most PADD 3 refineries do not require selective catalytic reduction or oxidation catalysts, which are the best control method for nitrogen oxides and carbon monoxide emissions. Fox Report at 4-5.

The DSEIS's reliance on permitting to avoid the obligation to analyze air quality impacts is legally and factually flawed. The DSEIS must actually analyze the impacts of the project on air quality in the area of the refineries.

e. The Project Increases the Likelihood of Accidental Releases at Receiving Refineries

Because tar sands diluted bitumen has different chemical properties than conventional heavy crude, it could create significant safety hazards at receiving refineries, which are not equipped handle the unique chemical composition of WCSB crudes without significant upgrades. Fox Report at 27. Similar changes in crude slates caused the explosion at the Chevron refinery in Richmond, California, on August 6, 2012. Fox Report at 27-28. That accident affected over 15,000 people from the surrounding area. Fox Report at 28. The DSEIS must evaluate the risk of similar accidental releases at refineries that will process the crude transported by the project.

f. The Project Will Increase Levels of Polluted Wastewater Produced by the Refineries

Wastewaters generated from processing tar sands crudes in PADD 3 refineries will contain higher concentrations of many pollutants, including metals, sulfur compounds, ammonia, chemical oxygen demand (COD), oil and grease, suspended solids, salts, benzene, phenols, and sulphides. Fox Report at 26-27. Thus, as with air quality, a switch to refining tar sands crude will increase water pollution at refineries. The DSEIS fails to analyze this impact of the project at all.

9. <u>The DSEIS Fails to Adequately Analyze Environmental Justice, and the State Department Has Failed to Engage Environmental Justice Communities in the Process</u>

The DSEIS fails to perform necessary environmental justice analysis to consider disproportionate impacts of existing toxic hot spots in people of color and low-income communities in Texas refinery-industrial areas such as Port Arthur, East Houston-Manchester, Beaumont, and others impacted by Keystone XL.

President William Clinton's February 11, 1994 Executive Order No. 12898, affirms and prescribes fundamental requirements for federal agencies including the DOS to insure that all federal programs and federally funded agencies shall not be allowed to increase the disproportionate burdens of environmental hazards in communities of color and low-income neighborhoods, including industrial-impacted communities such as, for example, Port Arthur, Beaumont, and East Houston-Manchester, Texas.

However, instead of analyzing the refinery emissions and their impacts on public health and environmental justice communities, the State Department simply claims that the crude slate would be essentially the same so that the change in emissions would be negligible. In fact, even compared with refining other heavy sour crudes, refining the same amount of tar sands in Gulf Coast would cause significantly more pollution in low income communities and communities of color surrounding the refineries that would process the tar sands from Keystone XL, many of which are located in ozone non-attainment areas – surely constituting a disproportionate burden of environmental hazards.

Further, Title VI of the Civil Rights Act of 1964, 42, U.S.C. § 2000d and its implementing regulations which are codified at 40 C.F.R. Part 7 ("Title VI") prohibits discrimination in programs using federal funds – including the environmental review process for Keystone XL. U.S. Department of State should fully comply with Title VI of the Civil Rights Act of 1964. In a revised DSEIS, DOS should conduct an impartial environmental justice analysis of the disproportionate impacts of existing toxic hot spots in people of color and low-income communities in Texas refinery-industrial areas such as Port Arthur, East Houston-Manchester, Beaumont, and others, giving the public adequate opportunity for public input on this analysis. In addition, CEQ states in its environmental justice guidance that, "[m]itigation measures identified in an EIS … should reflect the needs and preferences of affected low-income populations, minority populations, or Indian tribes to the extent practicable."[474] CEQ urges agencies to, "carefully consider community views in developing and implementing mitigation strategies" and "elicit the views of the affected populations" on mitigation measures, and agencies should do so *throughout* the public participation process.[475,476] (Emphasis added.)

To comply with the Civil Rights Act of 1964 and CEQ's environmental justice guidance, the DOS should have held hearings in Port Arthur or Houston, TX in order for affected EJ communities to explain the potential impacts to these communities. DOS must engage the impacted communities directly about their mitigation preferences and emergency management and needs, as CEQ's environmental justice guidance directs the State Department to do.[477] The State Department can begin engaging communities by enhancing public participation efforts.

a. Health Impacts from Oil Refineries Processing Tar Sands Crude Were Downplayed and Ignored in the EIS process

Adverse health impacts can occur from exposure to toxic, hazardous and noxious

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[474] Council on Environmental Quality's guidance document, "Environmental Justice: Guidance Under the National Environmental Policy Act," (CEQ 1997 at page 16).
[475] *Id.*
[476] We discuss the need for community meetings or field hearings in the public participation discussion, below. Such meetings or hearings would provide an opportunity to gather community views and preferences with respect to appropriate mitigation.
[477] CEQ guidance, *supra*, at page 16.

chemicals and wastes. As described in the Fox report and in the section of these comments addressing refinery pollution (above), Keystone XL would cause an increase in processing of tar sands, which would cause increases in hazardous air pollutants, VOCs and other ozone pre-cursors, and a range of other pollutants – an especially significant concern in the communities of color and low-income neighborhoods surrounding the refineries that would likely process the tar sands, many of which are located in 8-hour ozone non-attainment areas.

The Canadian tar sand crudes also contain high levels of heavy metals (including lead, nickel, chromium, boron, arsenic, zinc, and vanadium), solid residues, carcinogenic components, developmental toxins, birth defect toxins, neurological toxins, reproductive toxins, immunological toxins, endocrine disrupting toxins, cardiovascular toxins, respiratory toxins, gastrointestinal toxins, liver toxins, kidney toxins, musculoskeletal toxins, skin or sense organ toxins, and others. Many of the chemicals listed above are known to be toxic to humans, animals, fish, plants, and microbes at particular levels of exposure.[478]

Community members living in affected neighborhoods of the Port Arthur's and East Houston's industrial pipeline and refinery districts will be adversely exposed, in some cases for years, to harmful substances through a variety of pathways, including breathing contaminated ambient air outdoors, enduring skin exposures from toxic vapors, ingestion of contaminated soil by children, tracking contaminated soils into living quarters, drinking contaminated water, eating garden grown contaminated foods, toxic vapor intrusion into poorly sealed living quarters, dangers due to fire and explosion hazards from pipeline spills and leaks, and other impacts due to the operations of the TransCanada's Keystone XL tar sands industrial pipeline and the local Texas oil refineries processing the dirty tar sands crude oil.

The failure by the State Department to conduct a complete review of the pollution and public health impacts of refining hundreds of thousands of barrels per day of tar sands in low income communities and communities of color already facing high levels of pollution appears to be an attempt to minimize the apparent impacts to affected EJ communities and flies blatantly in the face of EO 12898.

At least 12 Texas Gulf Coast refineries may seek tar sands: 3 Valero refineries, 2 Exxon, and 7 other refineries. In many of the communities where these refineries are located, they are among the largest polluters of regulated air toxics and criteria pollutants under the federal Clean Air Act.[479]

A. 4 Jefferson County refineries - Port Arthur and Beaumont:

Exxon Beaumont refinery - 6034 tons criteria emissions

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[478] Letter from Neil Carman, et. al to John Robinson, Director Office of Civil Rights Department of State (October 20, 2011). Attached as Exhibit 105.

[479] Criteria pollutant emissions for Jefferson, Harris, and Galveston County, TX can be found in: Letter from Neil Carman, et. al to John Robinson, Director Office of Civil Rights Department of State (October 20, 2011).

Valero Port Arthur refinery - 5834 tons

Motiva Port Arthur refinery - 3927 tons

Total Port Arthur refinery - 2019 tons

Total criteria air emissions for above four refineries: 17,814 tons emitted in 2009

B. 5 Harris County refineries - Houston Ship Channel:

Shell Deer Park refinery - 7940 tons

Exxon Baytown refinery - 7398 tons

Pasadena Refining - 4055 tons

Houston Refining - 2350 tons

Valero Houston refinery - 613 tons

Total criteria air emissions for above five refineries: 22,356 tons emitted in 2009

C. 3 Galveston County refineries - Texas City, Texas:

BP Texas City refinery - 7523 tons

Valero Texas City refinery - 1900 tons

Marathon Texas City refinery - 996 tons

Total criteria air emissions for above three refineries: 10,419 tons emitted in 2009

Large oil refineries in Texas typically have significant toxic emissions compared to other industrial facilities and are related to serious public health impacts of air emissions due to carcinogens like benzene and other toxic substances. Texas refineries rank among the dirtiest sources of toxic air pollution in Texas among nearly 2,000 industrial factories in the state, which was totally downplayed and ignored in the FEIS by the DOS. Benzene-containing “aromatics” are among the more toxic substances emitted by oil refineries. Soot is also highly toxic and is emitted from many combustion units at refineries such as the heaters, boilers, cracking units, sulfur recovery units, flares, and other units. Refineries routinely emit dozens of toxic substances including carcinogens like benzene, benzo[a]pyrene and lead. Adding to the already-disproportionate environmental impacts faced by the communities surrounding many of these refineries is a major environmental justice concern that must be analyzed by the State Department, looking not just at the impacts from Keystone XL but how they would fit in with the significant burdens already faced by low income communities and communities of color.

b. The DSEIS Fails to Adequately Analyze Impacts in Houston[480]

As one of the country's largest cities and primary ports, Houston unsurprisingly possesses one of the largest air pollution problems in the United States. There are over 400 chemical manufacturing facilities in Houston, including 2 of the 4 largest refineries and the largest petrochemical complex in the country (Texas Observer, 3/3/2007). Due at least in part to the absence of zoning laws in Houston, Houstonians often live precariously close to large industrial facilities. Poor and minority residents are far more likely to be located near industrial or waste facilities, and therefore bear much of the burden of Houston's largely industrial based economy. This raises a number of health, safety, and environmental justice.

This issue is perhaps most difficult in East Houston, which is home to the United States' largest concentration of petrochemical plants and at least 30 refineries and petrochemical plants (Dallas News and Texas Observer). In fact, according to A Closer Look at Air Pollution in Houston, Identifying Priority Health Risks: The Mayor's Task Force on The Health Effects of Air Pollution, (herein The Mayor's Task Force Report), half of all point sources of pollution in Houston are found in the eastern region. This pollution is compounded by substantial non-point source air pollution created by The Port of Houston and the Ship Channel that winds through East Houston and a large concentration of high volume freeways, including Interstate highways 10, 610 and 45 and State Highway 225 (and 35 in the southeastern portion) (Mayor's Task force Report).

In The Mayor's Task Force Report, East Houston neighborhoods were found to have significantly higher levels of "definite risk" air pollutants than in the rest of Greater Houston. While 80% of Houston census tracts have 3 or less of these pollutants at a level of definite risk, 90% of census tracts in East Houston contain four or more definite risk pollutions at a high level. Half of the census tracts with 6 or more definite risk pollutants at high-risk levels are located in East Houston. This is particularly alarming when considering that pollutants may have cumulative effects. Additionally, a study by the University of Texas School of Public Health revealed that "children living within two miles of the Ship Channel had a 56 percent higher risk of contracting acute lymphocytic leukemia than children living more than 10 miles from the channel," (Houston Chronicle, 1/17/07). Furthermore, East Houston, or the neighborhoods surrounding the Ship Channel, are comprised of predominantly low-income and minority populations, making it a prime area of environmental justice concerns. The State Department should be sure to include the cumulative effects of the existing pollution in this region along with the pollution caused by refineries processing tar sands from Keystone XL.

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480 Environmental Justice in The East Houston Ship Channel: Rethinking the Chavez High School Location http://soa.utexas.edu/files/gis/EnvironmentalJusticeHoustonShipChannel.pdf.

10. The DSEIS Fails to Analyze Impacts to Threatened and Endangered Species Under NEPA and the ESA

In prior comment letters, we have notified the agencies about the need to incorporate analysis of impacts to species that are protected as threatened or endangered under the Endangered Species Act, 16 U.S.C. §§ 1531-1544 ("ESA"). Many impacts of the Keystone XL pipeline to threatened and endangered species ("TES") have not been adequately analyzed in any prior environmental review. This is true for the DSEIS and 2012 Biological Assessment ("BA") as well.

The DSEIS and BA lack information about the pipeline's impacts to threatened, endangered, and sensitive ("TES") species – including the whooping crane, piping plover, interior least tern, western prairie-fringed orchid, pallid sturgeon, and American burying beetle – that must be disclosed and analyzed under NEPA. As with prior environmental reviews, the DSEIS and BA lack:

- Survey information regarding the locations of TES within areas affected by the pipeline. Although the DSEIS notes that field surveys have been or will be conducted for specific species (black-footed ferret, interior least tern, piping plover, Western prairie fringed orchid, small white lady's-slipper, greater sage-grouse, sharptailed grouse, and American burying beetle), the DSEIS does not actually disclose the results of such surveys where they are complete. Instead, the DSEIS states that survey information is included in the BA. However, this information is not provided in the BA, as it has been withheld from disclosure to the public. *See* BA at Appendices H-P (withholding results of species surveys as "confidential"). The results of all field surveys must be disclosed under NEPA. 40 C.F.R. § 1500.2(d); *id*. §1500.1. *id*. § 1506.6(b), and the ESA. A determination of whether the pipeline is the national interest, given its impacts to TES, simply cannot be made without this factual information. There is no basis for failing to provide this information, and its absence undermines the analysis under NEPA as well as under the ESA. There is no way to verify the agencies' conclusions regarding the pipeline's effects to TES species – including its determinations that the pipeline will have acceptable impacts to TES species – without it.

- The total amount of TES habitat that would be affected, temporarily and permanently, including occupied habitat as well as habitat that is suitable and may be occupied in the future. This information has never been provided and remains lacking in the DSEIS and BA.

- The number of miles of all transmission power lines to service pump stations for the pipeline, and where these power lines will be sited in relation to TES and sensitive species occurrences or recovery areas. This information remains lacking from the DSEIS and BA. While some information regarding the locations of pump stations is provided, BA at Appendix A, the precise locations of *all* power lines that would service the pump stations are not. Under NEPA and the ESA, the power lines are connected actions and interrelated with and interconnected to the project, and hence the federal agencies must disclose and consider their effects. 40 C.F.R. § 1508.25(a)(1) (Connected actions include "interdependent parts of a larger action and depend on the larger action for their justification"); *id*. § 1500.2(d); *id*. §1500.1. *id*. § 1506.6(b); *see also* 50 C.F.R. § 402.02 (definition of "action area" under the ESA includes "all areas to be affected directly or indirectly by the Federal action and not merely the immediate area involved in the action").

- Analysis of the effects of power lines to TES is delegated to local power providers. Local power providers have no obligation to comply with NEPA or ESA section 7(a)(2), and may withhold information from requesters regarding the precise locations of power lines and/or listed species. For example, the DSEIS states that the construction of new electrical distribution lines will "incrementally increase the collision hazard for migrating whooping cranes because a portion of the proposed Project area is located within the primary migration corridor [whooping cranes." A previous FWS analysis of "suitable migration stopover habitat in relation to … preliminary routes for associated transmission lines" for Keystone XL "identified 74 locations within the primary migration corridor where new transmission lines could potentially increase collision hazards for migrating whooping cranes."[481] Yet, information about such locations and the risk to whooping cranes and any other affected species (such as sandhill cranes) is not disclosed or discussed in the DSEIS. Details about the locations of new collision hazards within the migration corridors for TES and other wildlife species is lacking. Also lacking is information about the expected effects to TES and other wildlife species if recommended measures are not implemented – *e.g.*, what will be the effect to whooping cranes if power lines are not buried but diverters or reflectors are used instead? Diverters and reflectors are not 100 percent effective.[482] Particularly when combined with the absence of TES and sensitive species survey data, *see* above, the DSEIS and BA simply fail to analyze the environmental consequences of the pipeline to species that will be affected by power lines.

- Locations of pipeline waterbody crossings or the crossing methods that would be utilized. Waterbody crossing methods for specific waterbodies remain are absent from the SDEIS. And, although the DSEIS states that the horizontal directional drill ("HDD") method will be used at some waterbody crossings, it does not

[481] *See*, FWS, *Rationale for concurrence with species NLAA determinations in the Final Biological Assessment for the Keystone XL pipeline project* (undated), attached as Exhibit 106.
[482] *See*, *e.g.*, Marcus L. Yee, California Energy Commission, Testing the Effectiveness of an Avian Flight Diverter for Reducing Avian Collisions with Distribution Power Lines in the Sacramento Valley (2008), attached as Exhibit 107.

disclose precisely where such waterbody crossings would be located, or rigorously analyze the risk of "frac-outs" that can result from the use of the HDD waterbody crossing method at those places. The DSEIS dismisses these effects on the basis that they are unlikely. However, frac-outs are more common than the DSEIS would suggest. For example, the Connecticut Department of Environmental Protection has found that frac-outs occur in at least half of the projects it has regulated.[483] Even if infrequent, the agency is required to consider the effects of frac-outs at specific locations in the event that they do occur.

- Information regarding the effects of spills to listed species. Unlike the previous Biological Assessment prepared for the Keystone XL project in 2011, the new Biological Assessment (2012) acknowledges that the pipeline will result in releases, spills, and leaks. Nevertheless, both the DSEIS and BA still fail to consider the effects to listed species when such spills do occur. *See* BA at 2.0-61 – 2.0-63. Instead, the BA devotes its consideration of this impact to a discussion of how clean-up measures will be employed in the event of a spill. *Id*. However, tar sands spills are very difficult, even impossible, to remove from the environment once they occur. Hence, the absence of any consideration of the effects to listed species when spills occur is in error. Moreover, the DSEIS and BA also fail to disclose critical information regarding spills and the required response to them, as the relevant document – Appendix D to the BA (the Spill Prevention, Control and Countermeasure (SPCC) Plan and Emergency Response Plan (ERP)) – was not disclosed along with the DSEIS.

- Analysis of the pipeline's effects in combination with conditions in the areas that will be affected by the project throughout its lifespan. Such conditions include the intensifying impacts of climate change, human population growth and development, and a proliferation of pipelines within the affected area, combined with analysis of the pipeline's cumulative effects. A vast range of human activities have already altered the affected landscapes, including agricultural production, urban development, mining, timber harvesting, energy development, transportation, infrastructure improvements. Innumerable activities, similar in nature to what was described above, are reasonably foreseeable within the vicinity of the affected area based on expected population increases, and associated urbanization, economic development, and infrastructure improvements including transportation, utilities, and other pipelines. Yet, the DSEIS and BA are devoid of any analysis of the pipeline's cumulative effects to TES when combined with the effects of these activities.

[483] *See*, excerpts from Island East Decision (Dec. 19, 2006), attached as Exhibit 108 (noting that "[i]t has been the experience of the Department that frac-outs occur in at least half of the HDD projects75 it has regulated").

Despite the need for all of this information, the agencies have not provided it in the DSEIS or BA. Its absence necessitates preparation of another draft supplemental EIS and BA, as this is the stage when such information must be disclosed and analyzed by the agencies.

There are additional flaws that must be corrected in another supplemental NEPA analysis or a FSEIS as well:

- The DSEIS and BA define the environmental analysis based on a constrained interpretation of the affected environment. While the "project area" is not defined in the DSEIS, this term appears to refer to the direct footprint of the pipeline path and its immediate vicinity. However, both NEPA and the ESA require the agencies to rigorously consider the project's effects to resources wherever they occur, and not based on an arbitrary delineation. NEPA requires analysis of and a hard look at all "impacts" from Keystone XL, regardless of where such effects occur. ESA section 7(a)(2) consultation specifically requires consideration of effects in the "action area," which is defined to include "*all* areas to be affected directly or *indirectly* by the Federal action *and not merely the immediate area involved in the action*." 50 C.F.R. § 402.02. By limiting the analysis of the pipeline's environmental consequences to the "project area," some of the pipeline's worst environmental impacts are omitted from consideration. For example, the assessment of potential impacts to interior least terns and piping plovers is limited to the locations where the pipeline will cross waterbodies and where these species have been found to occur. However, there is no basis for limiting environmental analysis to waterbody crossings and their immediate vicinity. When spills occur – as has been made evident with recent spills by Keystone I, the Kalamazoo River, Arkansas, and other examples – the oil migrates throughout the affected watershed(s). There is no rationale for basing the environmental review on the pipeline footprint and its vicinity when oil spills migrate outside of these areas. Another example is the lack of any analysis of the impacts of the pipeline or mining of tar sands bitumen in Alberta, which is impacting two endangered species: woodland caribou and whooping cranes. Closely related to this problem is the lack of analysis of the pipeline's environmental consequences in combination with environmental conditions currently as well as throughout the pipeline's lifespan.

- The DSEIS suffers for the lack of analysis about the pipeline's impacts if construction occurs during TES active seasons. For example, although the DSEIS acknowledges that construction during the active season for interior least terns could result in nest abandonment or predation, *see* DSEIS at 4.8-12, the proposed action includes no *requirements* that construction occur outside of the active season (April 15-August 15). Similarly, there are no requirements that Keystone bury power lines, install bird diverters and reflectors to protect, *e.g.*, whooping cranes, interior least terns, and piping plovers. This is unacceptable. Without such parameters being mandatory, the agency must disclose and rigorously analyze the impacts to listed species' ability to survive and recover from these pipeline impacts. In this connection, it must be noted that simply deeming such measures (such as bird diverters) as "conservation measures" does not make them nondiscretionary to protect species that are protected as endangered or threatened. Conservation measures are only mandatory if they are incorporated into a biological opinion. However, because the agencies are failing to complete formal consultation in accordance with the ESA for any species other than the American burying beetle, there will be no biological opinion which includes such measures as "conservation measures" under the ESA, which would make the measures non-discretionary. As a result, the DSEIS must, but fails, to analyze the pipeline's impacts to listed TES in the event that such measures are not implemented.

- Another flaw concerns the temporal scope of the environmental reviews for Keystone XL. Environmental reviews for Keystone XL have been based on an anticipated lifespan of 50 years, but such analyses should assume that the pipeline will be in operation for much longer. *See* KXL FEIS (2011) at 2-64 (noting that pipeline operators may simply extend the duration of pipeline systems by replacing sections of pipe and replacing or upgrading equipment and facilities at pump stations). Indeed, TransCanada has proposed a "much longer" life span for Keystone XL than 50 years, and the agencies have acknowledged that "it is not possible to identify a specific number of years that the proposed Project may be in service." *Id*. Other pipelines have outlasted their projected lifespans – *e.g.*, the Exxon's Pegasus pipeline, which is 65 years old and leaked on March 29, 2013 from a rupture that was 22 feet long and two inches wide, causing devastating effects to wildlife. As pipelines age, they rupture and spill more easily. Hence, the project spill rate for Keystone XL – about twice per year for 50 years, *see* KXL FEIS (2011) at Executive Summary – will likely change as the pipeline ages. Thus, to fully account for the pipeline's effects to any affected environmental resources, the agency should assume that the pipeline would be in operation for much longer than 50 years and revise its environmental reviews of the project accordingly.

Finally, although these comments regarding the pipeline's effects to TES are focused primarily on NEPA issues, we maintain that the ESA requires the agencies to complete formal consultation with FWS to develop a biological opinion that considers the adverse effects to TES from the pipeline and provides an incidental take statement to account for the take that will result. When the actual impacts of the pipeline are considered, it is clear that several species will be adversely affected by the pipeline and its impacts will include "take" of wildlife. At a minimum, such species include whooping crane, piping plover, interior least tern, western prairie-fringed orchid, and pallid sturgeon. The agencies will be in violation of ESA section 7(a)(2) and section 9 without completing formal consultation for these species. Such consultation should be completed concurrently with a revised DSEIS and circulated for public review and comment, in accordance with NEPA's implementing regulations. 40 C.F.R. 1502.25(a) ("To the fullest extent possible, agencies shall prepare draft environmental impact statements concurrently with and integrated with environmental impact analyses and related surveys and studies required by … the Endangered Species Act … ."); *id*. § 1507.1(a)(6) (requiring the State Department to "[i]dentify other environmental review and consultation requirements" so that it may prepare them "concurrently with, and integrated with, the [EIS]").

11. <u>The DSEIS Fails to Adequately Analyze Impacts to Wildlife</u>

a. The DSEIS Fails to Properly Consider Wildlife Impacts in the Event of Pipeline Spills

The inclusion of additional discussion regarding impacts of dilbit spills in this DSEIS further illustrates the very troubling concerns this fuel sources raises. In order to fully consider the impacts of this proposed project, the State Department must provide an adequate analysis of impacts that potential pipeline spills would have on wildlife. It has not done so.

The Mayflower, Arkansas spill has dramatically illustrated the risks of a spill to wildlife and called further attention to the deficiencies in the SEIS. This spill, which was relatively small compared to the disastrous Kalamazoo spill and impacted primarily developed residential areas along with surrounding wetland areas and a perhaps a section of Lake Conway, still had a significant impact on wildlife. Eleven days after the spill had occurred, 140 animals were being treated after being exposed to diluted bitumen,[484] although individuals on the scene speculated that hundreds or perhaps even thousands of affected animals had not been captured for treatment. The impacts of a spill like this on sensitive; endemic; culturally significant; or threatened, endangered, or otherwise protected wildlife species is significant and this draft SEIS fails to take a hard look at the specifics of this risk to wildlife.

As discussed in greater detail elsewhere our comments regarding the risk of spills to waterways, we have already seen the catastrophic impacts of a tar sands spill in the Kalamazoo River. Approximately 4,000 animals were treated for injuries as a result of the spill and many required significant care before being released back into the environment.[485] Responders estimated that, "whatever the final tally of dead wildlife is, the real number will be almost three times higher because some oil in hard-to-get-to floodplain areas is being allowed to break down over time — oil that could potentially contaminate animals."[486] Countless animals such as turtles and geese died slow deaths as a result of the 2010 Kalamazoo spill.

The DSEIS often references Enbridge's Line 6b's spill in the Kalamazoo, the only major dilbit spill in the U.S. "By examining the effects from the 2010 Enbridge spill, the potential

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[484] EPA/Mayflower Incident Unified Command Joint Information Center, *Cleanup Operations Continue in Mayflower, AR* (April 10, 2013).
[485] *See*, Ex. 98 at 63 (A wildlife response center was established with the cooperation of Enbridge, the U.S. Fish and Wildlife Service, and the Michigan Department of Natural Resources and the Environment. The response center cared for and released about 3,970 animals—of 196 birds treated, 52 were not released).
[486] <u>http://www.mlive.com/news/kalamazoo/index.ssf/2010/10/wildlife_rehab_continues_after.html.</u>

impacts to wildlife from a spill of similar size/magnitude can be evaluated."[487] However, it does not seriously consider that because the proposed Keystone XL pipeline would carry substantially more dilbit than Line 6b, it follows that any spill from this line would likely result in an even more massive release of dilbit into the environment. The DSEIS flags this issue, noting that "magnitude of effects varies with multiple factors, the most significant of which include the amount of material released, the size of the spill dispersal area, the type of crude oil spilled, the species assemblage present, climate, and the spill response tactics employed."[488] However, it does not analyze what this means in the context of this pipeline spilling, it just mentions this issue in general terms. Because a spill from the substantially larger proposed Keystone XL pipeline would likely result in an even larger release of dilbit than the release in the Kalamazoo, the State Department must not just rely on Kalamazoo as its measure of a catastrophic spill but must consider an even more substantial release of dilbit into the environment. To this end, additional modeling and analysis that factors in what we have learned from both the Kalamazoo and Mayflower spills, is needed.

The DSEIS mentions that some of the wildlife impacts of this proposed pipeline spilling include oiling which could result in smothering, coating of feathers resulting in hypothermia, and oil weighing down animals so they cannot move.[489] It also mentions chemical and toxicological wildlife impacts including mortality resulting directly from contact with the tar sands oil; sub-acute toxicity resulting in disorientation and interference with feeding and reproduction, reduced disease resistance, and tumors; interference with biochemical and genetic processes; and "many other acute or chronic effects."[490] The DSEIS also notes that the impacts of dilbit spills on wildlife are long lasting. "Dilbit released into an aquatic environment could sink to the bottom of the water column…[and] result in a persistent source of oil."[491]

Table 4.13-5[492] purports to evaluate potential impacts to resources but this table is wholly subjective. The DSEIS offers no scientific justification for the conclusions drawn, which largely diminish the very significant concerns the public has regarding wildlife and terrestrial habitat; water, wetlands, aquatic habitat/organisms; and land use. A new and scientifically based analysis of impacts to these resources is necessary.

The greatest defect of the DSEIS's analysis of the wildlife impacts of the proposed Keystone XL Pipeline spilling is that the analysis attempts to generalize the impacts along the entire pipeline route, a route which crosses many unique and diverse habitat types filled with equally unique and diverse wildlife populations. With limited exceptions[493] the DSEIS fails to consider any specific species or locations. While it provides some analysis of impacts to

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[487] DSEIS, at 4.13-40.
[488] *Id*.
[489] *Id.* at 4.13-23.
[490] *Id.* at 4.13-24.
[491] *Id.* at 4.13-26.
[492] *Id.* at 4-13-32.
[493] *Id.* at 4.13-41.

mammals and birds,[494] it completely fails to consider specific impacts to fish or invertebrates. This is despite the fact that turtles were the most heavily impacted animals in the Kalamazoo spill[495] and that numerous scientific reports have made clear that fish eggs laid on sediment contaminated by bitumen have shown frequent death or physical abnormalities including spinal deformities, lesions, hematomas, and eye defects. [496] This failure must be remedied. The DSEIS states:

> Additional biological and ecological impacts may manifest in local populations, communities, or entire ecosystems depending on the location, size, type, season, duration, and persistence of the spill, as well as the type of habitats and biological resources exposed to spilled oil. Except for some endangered, threatened, or protected species and their habitat, loss of a few individuals of a larger population of organisms would result in a minimal impact at a community or ecosystem level. <u>On the other hand, reproductive impairment caused by toxicity could reduce an entire population or biological community, resulting in a significant environmental impact.</u> The impact is likely to be greater if the species affected have long recovery times (e.g., low reproductive rates, adverse genetic mutations); limited geographic distribution in the affected area; are key species in the ecosystem; are key habitat formers (those animals that substantially contribute to the formation of an environment); or are otherwise a critical component of the local biological community or ecosystem. Furthermore, if the species or community is a key recreational or commercial resource (e.g. tourist draw, hunted resource), biological impacts manifested at the population or community level may constitute a significant impact to human uses of the resource."[497]

While the DSEIS calls out this issue as significant, it fails to delve into any of the specifics regarding the potential spill impacts to wildlife species of most significant concern. To pass muster the DSEIS must specifically consider impacts to particular species of having long recovery times, limited distribution, key species in an ecosystem, key habitat formers, species that are critical components of local communities or ecosystems, and species that are key recreational or cultural resources. The general analysis in this DSEIS is simply not enough.

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[494] *Id.* at 4-13-41.

[495] <u>http://www.mlive.com/news/kalamazoo/index.ssf/2010/10/wildlife_rehab_continues_after.html</u>

[496] Colavecchia, M.V., Backus, S.M., Godson, P.V. & Parrott, J.L. (2004). Toxicity of oil sands to early life stages of fathead minnows (Pimephales promelas). Environmental Toxicology and Chemistry, 23:7, 1709-1718.
Colavecchia, M.V., Hodson, P.V. & Parrott, J.L. (2006). CYP1A induction and blue sac disease in early life stages of white suckers (Catostomus commersoni) exposed to oil sands. Journal of Toxicology and Environmental Health, 69:10, 967-994.
Colavecchia, M.V., Hodson, P.V. & Parrott, J.L. (2007). The relationships among CYP1A induction, toxicity, and eye pathology in early life stages of fish exposed to oil sands. Journal of Toxicology and Environmental Health, 70:18, 1542-1555.

[497] *Id.*at 4-13-26 (emphasis added).

b. Migratory Birds

As we have stated in previous comments, the Migratory Bird Treaty Act (MBTA) mandates that the proposed project must avoid the take of migratory birds entirely and must minimize the loss, destruction, and degradation of migratory bird habitat. At least 130 bird species protected by the MBTA breed in, or migrate through, habitat located in the tar sands area. Those species include water and shore birds (including cranes, ducks, geese, sandpipers, egrets and herons) and insectivorous birds (including sparrows, thrushes, phoebes, flycatchers, chickadees, woodpeckers, wrens, swallows, and finches). U.S. courts have found that deaths of protected birds resulting from oil sump pits and other contamination related to oil production are takings or killings under the MBTA.[498] As was the case with previous NEPA documents on Keystone XL, the DSEIS has failed to ensure compliance with MBTA or ensure that the take of migratory birds will be prevented. It also fails to provide any specific analysis of how a potential spill would impact protected migratory birds, only considering spill impacts to birds generally.[499] Finally, it fails to respond to the information requests of other agencies.

The DSEIS provide a list of general impacts to wildlife that includes habitat loss, alteration, fragmentation; direct mortality during construction and operation; indirect mortality due to stress or avoidance; reduced breeding success; and reduced survival or reproduction due to loss of edible plants and cover.[500] The DSEIS also notes that migratory birds may be attracted to the pipeline corridor during early spring if it becomes snow-free earlier than other surrounding habitats.[501] Finally, the DSEIS notes that migratory raptor species in the proposed Project area are generally considered sensitive and in need of specialized protective measures.[502] However, the DSEIS does not actually talk about what these impacts mean for these species. For example, it does not answer the question of what are the impacts of a species deviating from its usual migration route to follow a snow free pipeline route? Additionally, the DSEIS does not adequately consider other issues continually raised by commentators such as the impacts of toxic tailing ponds to migratory bird populations.

The DSEIS provides a list of general special buffer restrictions to be established during nesting season for raptors, including bald eagles and other species protected by the MBTA. These buffers are premised on the notion that agencies have identified all potentially impacted species. However, our experience indicates this is not the case. Conservation groups were contacted by a Nebraska landowner who had repeatedly reported a bald eagle's nest directly

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[498] *See United States v. Moon Lake Elec. Ass'n, Inc.*, 45 F. Supp. 2d 1070, 1083 (D. Colo. 1999) (citing three cases in which the United States charged oil companies for deaths of protected birds resulting from the oil company's construction, maintenance, or operation of its oil sump pits).
[499] DSEIS, at 4.13-41.
[500] *Id.* at 4.6-3.
[501] *Id.* at 4.6-8.
[502] *Id.* at 4.6-10.

along the proposed pipeline route to state regulators.[503] Frustrated by the complete lack of acknowledgment from state agencies, he reached out for help and was finally put in touch with USFWS, who subsequently reached out to the State Department and TransCanada about the need to avoid this eagle's nest. The fact that a known eagle's nest directly along the pipeline route was ignored by the Nebraska Department of Environmental Quality and it took the efforts of numerous individuals to bring this issue to the attention of regulators casts doubt on the ability of the State Department and TransCanada to ensure that appropriate buffer restrictions are established during nesting season. Many nests remain unknown or hidden that the DSEIS improperly relies on these buffers without acknowledging that in many instances, it simply will not be aware of the presence of protected bird species.

Other agencies including the USEPA and USFWS have commented extensively on their concerns about migratory birds resulting from this project. None of the NEPA documents associated with the proposed Keystone XL Pipeline have adequately addressed these concerns. The impacts of pump stations, transmission and electrical lines, loss of habitat resulting from blasting and ripping of rock outcrops used for nesting and foraging, or the massive number of deaths that have resulted from birds landing in toxic tailing ponds are all issues that commentators have repeatedly raised. These comments have not been adequately addressed in the DSEIS. We have commented on this problem in depth in past comments but the failure of State to respond to even the simplest requests from other agencies remains astounding. For example, EPA has asked for State to include "additional information that would address potential impacts to *specific* migratory species, with an emphasis on already-vulnerable species."[504] This request has been echoed by other agencies such as DOI and the undersigned commentators, but has been ignored. State has also ignored reasonable information requests such as EPA's request that it include basic data from the North American Breeding Survey in its analysis.[505] The lack of basic data or citations to support the conclusions stated in the DSEIS make it impossible for other agencies and members of the public to provide State well informed comments on migratory bird issues, leaving us no choice but to utilize the Freedom of Information Act (FOIA) to attempt to access documents that would allow us to analyze this proposed project. Unfortunately, documents requested under FOIA did not arrive in time for inclusion in these comments.

In addition to not offering any evidence to back its claims regarding impacts to migratory species, State has also ignored requests from commentators to consider important information in formulating its analysis. For example, in our scoping comments on this DSEIS, we asked State consider the "State of Canada's Birds 2012" report. This highly relevant report indicates at least 55 bird species in Canada's boreal forest are currently in decline, names energy development as one of the biggest conservation concerns, calls for protection of special habitat, recommends

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[503] http://www.kearneyhub.com/news/state/keystone-pipeline-route-near-bald-eagle-nest-ruffles-feathers/article_0e22725c-5f13-11e2-bf10-001a4bcf887a.html

[504] Letter from Cynthia Giles, Ass't Administrator, Enforcement and Compliance Assurance, to Mr. Jose W. Fernandez, Ass't Secretary, and Dr. Kerri-Ann Jones, Ass't Secretary, U.S. State Department 8-9 (June 6, 2011) (emphasis added).

[505] *Id.* at 9.

restoration and monitoring requirements, and suggests "urgent action to prevent further climate change" to protect bird species.[506] State does not consider this report or any of the issues it raises in its analysis of impacts on migratory birds.

In response to comments from EPA and others requesting a discussion of "mitigation measures that are either currently or could be employed for identified species"[507] State asked TransCanada for a "synopsis of activities at the corporate level that TransCanada supports to provide broad scale mitigation to migratory species."[508] TransCanada responding by announcing a one million dollar donation to Ducks Unlimited to launch the "Ducks Unlimited/TransCanada Partnership regarding Habitat Conservation in the Missouri Coteau conservation in Saskatchewan and the Grand Bayou Hydrology Restoration project in Louisiana."[509] The DSEIS goes on to describe the goals of this partnership and conclude that, "with respect to wildlife, permanent impacts are not expected."[510] The announcement of a grant and subsequent partnership between the pipeline proponent and an organization does not even remotely resemble NEPA's requirement that the agency take a "hard look" at the environmental impacts of a project. This does not come close to an actual analysis of the cumulative impacts this project will have on migratory birds.

According to the State Department' 2012 Biological Assessment (BA), the proposed Keystone XL Pipeline project's "transmission line, electrical distribution lines, and substations could result in long-term increased bird collisions, bird predation, and habitat loss. However, with implementation of conservation measures, it is not expected that these lines would have cumulative impacts on birds protected under the MBTA or Bald and Golden Eagle Protection Act."[511] This conclusion is repeated three times in the BA, but mere repetition does not make the conclusion true nor does it overcome the fact that nowhere does the agency provide any rationale for this conclusion. Furthermore, this conclusion is premised on the voluntary implementation of a half page of conservation measures. The only one of these measures that specifically targets migratory birds is the development of a Migratory Bird Conservation Plan. However, the mere development of a Plan is not a conservation measure. Furthermore, the promise of a future plan is not a conservation measure. The conclusion that the lines associated with this Project will not have cumulative impacts is apparently based on the promises contained in a document that does not yet exist and thus is wholly unsatisfactory. Without any additional information, the public is left wondering and is not able to provide any substantive comments on a Plan or this conclusion.

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[506] The State of Canada's Birds 2012, published by Environment Canada on behalf of North American Bird Conservation Initiative Canada, http://www.stateofcanadasbirds.org/State_of_Canada%27s_birds_2012.pdf.
[507] Letter from Cynthia Giles, Ass't Administrator, Enforcement and Compliance Assurance, to Mr. Jose W. Fernandez, Ass't Secretary, and Dr. Kerri-Ann Jones, Ass't Secretary, U.S. State Department 9 (June 6, 2011) (emphasis added).
[508] DSEIS, at 4.15-47.
[509] *Id.* at 4.15-48.
[510] *Id.*
[511] DSEIS Appendix H, at 3.0-68

The State Department cannot continue to ignore the significant impacts Keystone XL and the subsequent increased development of tar sands oil will have for migratory birds. It must carefully consider the implications of this proposed project in light of its obligations under the MBTA.

c. The Fact that Tar Sands Extraction Results in Further Violation of Wildlife Treaties Requires Analysis in the DSEIS

This DSEIS fails to discuss the fact that tar sands extraction in Canada is resulting in the violation of international treaties and thus is subject to action under the Pelly Amendment. Commentators have raised this issue in past comment, noting that the violation of international treaties is an issue that should be considered in the various NEPA documents.

Canada has failed to take appropriate steps to ensure that tar sands development does not result in takings of species protected by the Western Hemisphere Convention and Migratory Bird Convention. As a result, Canada and the oil companies engaged in tar sands extraction in Canada have diminished the effectiveness of these Conventions, especially those Conventions' provisions requiring special protection for listed species, including whooping crane and woodland caribou. Tar sands extraction is directly killing and destroying important habitat of 130 migratory bird species—including the endangered whooping crane—protected by the Western Hemisphere Convention and the Migratory Bird Convention. Tar sands operations also threaten woodland caribou protected by the Western Hemisphere Convention.

Recognizing this as a significant problem, on September 22, 2011, conservation groups, including commentators, filed a petition for certification, pursuant to the Pelly Amendment to the Fisherman's Protective Act of 1967,[512] of Canada for its failure to prevent takings of woodland caribou and migratory birds, including whooping cranes, resulting from large-scale tar sands development in Alberta, Canada.[513] Accordingly, the petitioners requested that the Secretary (a) investigate tar sands extraction activities in Alberta, Canada, as these activities may "be cause for certification" under the Pelly Amendment;[514] (b) determine that tar sands extraction "diminishes the effectiveness" of the Western Hemisphere Convention and the Migratory Bird Convention;[515] and (c) certify these facts to the President.[516] As stated elsewhere in these comments, the approval of the proposed Keystone XL pipeline will result in increased tar sands extraction. That this will result in even more take and further diminish the efficacy of these treaties that must be analyzed by State.

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[512] 22 U.S.C. § 1978
[513] A copy of this petition was included in our scoping comments.
[514] 22 U.S.C. § 1978(a)(3)
[515] *Id.* § (a)(2)
[516] *Id.*

d. The DSEIS Fails to Adequately Consider Spill and Other Impacts to Reptiles, Amphibians, Invertebrates, Crustaceans, and Aquatic Wildlife

A look at the types of wildlife primarily suffering the adverse impacted by the 2010 Kalamazoo diluted bitumen spill and the recent Mayflower diluted bitumen spill reveals that these spills primarily impacted reptiles, amphibians, and species such as ducks that rely on aquatic habitat. In Kalamazoo, the Binder Zoo veterinarian who cared for many of the impacted reptiles and amphibians reported taking in 1,795 animals including eight varieties of turtles, two types of snakes, two frog varieties, and one toad species.[517] According PHMSA, about 2,500 animals were treated, but the overwhelming impact was to turtles.[518] Some of these turtles were badly enough injured that they were still in the full time care of a veterinarian 15 months later.[519] The recent and much smaller Mayflower diluted bitumen spill has killed at least 205 animals within two weeks. That spill appears to have primarily impacted snakes, 129 have died so far, although several turtles and at least one duck were so sick they also required euthanasia.[520] From these two incidents it is clear that spills of diluted bitumen have significant impacts on reptiles and amphibians.

However, the DSEIS' discussion of spill impacts does not provide any specific or detailed analysis of impacts to reptiles or amphibians. Further, it fails to consider impacts to invertebrates, crustaceans, and many other aquatic species. This failure constitutes a failure to take a hard look at the impacts of the proposed Pipeline spilling and must be remedied.

In addition, the DSEIS devotes only a few short sentences to the significant impacts of this pipeline on reptiles, amphibians, invertebrates, crustaceans, and other aquatic wildlife. The SDEIS lumps these species under the title "non-game animals" and does not consider impacts to the various species within this massive subheading with any specificity.[521] The impacts it mentions, which include blocking movement, trapping large numbers in trenches and erosion control blankets, changes in vegetation cover, destroying hiburnacula and subsequently destroying habitat are all significant impacts likely to kill thousands of animals, but the DSEIS contains no discussion of what this means for these species or the impacted ecosystems. Thousands of invertebrate subspecies will likely be impacted by this project but the word invertebrate only appears twice in the wildlife section and no specific analysis on impacts to this species is provided. The two creatures mentioned with any specificity are bats, greatly imperiled across the nation due to white nose syndrome and snakes, which were the most significantly

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[517] http://www.binderparkzoo.org/kalamazooriver/
[518] *See* www.pstrust.org/docs/Kilian.ppt
[519] http://www.battlecreekenquirer.com/article/20111104/OILSPILL/111040320/Tainted-turtles-still-suffering-15-months-after-river-oil-spill?odyssey=tab%7Ctopnews%7Ctext%7CFrontpage&nclick_check=1
[520] http://arkansasmatters.com/fulltext?nxd_id=654912
[521] DSEIS, at 4.6-8.

impacted animals in the Mayflower spill.[522] The SDEIS mentions that construction of the pipeline could lead to the destruction of their habitats, but does not discuss what that means. Is there suitable alternative habitat nearby? How are the local populations currently faring? Are there endemic species who may become extinct as a result of these activities? Are these species expected to recover after the construction activity ceases? How will food chains be impacted by the loss of these species? What are the long term impacts on specific ecosystems when these species are so significantly impacted? How will this affect the viability of species already stressed from climate change and other developments? The five sentences devoted to these aforementioned vast families of species are wholly inadequate and constitute a serious failure to take a hard look at the impacts of this project.

12. <u>The DSEIS Fails to Adequately Analyze Impacts to Water Resources</u>

a. Oil Spill Impacts to Water and Wetlands

As these comments are being written, conflicting details continue to unfold regarding the impacts of the Arkansas' Pegasus Pipeline Spill on waterways. While Exxon has acknowledged the spill impacted a cove, it has insisted that the spill has not impacted nearby Lake Conway, a reservoir heavily used for fishing and other recreation. However, the Arkansas Attorney General has told reporters that this is not the case and indeed the Lake is contaminated, because "the "cove is part of Lake Conway."[523] Even if diluted bitumen does not directly spill into the main portion of the lake, the chair of the University of Central Arkansas' biology department has stated that impacts to the lake and other waterways will be significant because hydrocarbons and toxic chemicals "will be leeching out into the surrounding environment over a period of years."[524] Like most waterways, the hydrologic connections between the cove and lake – whether they are the same waterbody or not – mean that impacts to one will result in impacts to the other.[525] The creeks that feed the cove at issue appear to be, from an initial look at hydrologic networks around this spill, connected to Palarn Creek, Grassy Lake, and a large wetland area known as Bell Slough. Numerous creeks and wetlands miles from the site of the spill may still experience significant impacts from hydrocarbons and toxins from what is a still considered to be a relatively small oil spill. EPA's incident report two less than two weeks after the spill indicates that the agency is well aware of the possibility noting that "[c]leanup efforts are focused on the marsh area between the interstate highway and the cove adjacent to Lake Conway."[526] This incident in Arkansas highlights the far reaching impacts of diluted bitumen spills. State must update its analysis of impacts to water and wetlands in light of the new information gleaned from the spill in Arkansas.

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[522] *Id.*
[523] http://insideclimatenews.org/news/20130410/cove-where-exxon-oil-has-been-found-part-lake-conway
[524] *Id.*
[525] *Id.*
[526] EPA/Mayflower Incident Unified Command Joint Information Center, *Cleanup Operations Continue in Mayflower, AR* (April 10, 2013).

The spill section of the SEIS fails to analyze spill scenarios and how they would affect various resources, especially water. The impacts of a spill on different ecosystems vary as greatly as ecosystems vary, but the draft SEIS fails to take the important step of actually analyzing potential impacts of various spill scenarios on specific waterbodies and wetlands.

While it might be tempting for State to point to other regulatory entities for their role managing spill resource, the fact is that the existing regulatory framework is inadequate to regulate diluted bitumen spills and this must be factored into the NEPA analysis. In investigating the Kalamazoo spill, the National Transportation Safety Board found that, "[p]ervasive organizational failures by a pipeline operator along with weak federal regulations led to a pipeline rupture and subsequent oil spill in 2010… This accident is a wake-up call to the industry, the regulator, and the public."[527] The current regulatory structure is the same as the structure in place during the Kalamazoo spill. This must also be factored into the analysis of spill impacts on the environment. As the NTSB recognized, "[c]ontributing to the severity of the environmental consequences were … PHMSA's lack of regulatory guidance for pipeline facility response planning, [and] PHMSA's limited oversight of pipeline emergency preparedness that led to the approval of a deficient facility response plan."[528] Conservation groups recently submitted a rulemaking petition detailing the ways that existing regulatory mechanisms fail to adequately regulate diluted bitumen.[529] State must analyze this proposed pipeline project in light of the current regulatory structure that does not provide adequate measures to deal with diluted bitumen spills, particularly those that impact waters which the SEIS has already acknowledge pose difficult response challenges and long-term environmental harm.[530]

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[527] Press Release, National Transportation Safety Board, Pipeline Rupture and Oil Spill Accident Caused by Organizational Failures and Weak Regulations [hereinafter NTSB Press Release] (July 10, 2010), available at http://www.ntsb.gov/news/2012/120710.html.

[528] *See*, Ex. 98.

[529] http://www.nwf.org/~/media/PDFs/Global-Warming/Tar-Sands/Petition%20for%20Diluted%20Bitumen%20Rulemaking_CORRECTED.pdf

[530] "As with some other types of oil, Dilbit will not float on water indefinitely. The Dilbit-specific characteristics, water temperature, and particulate load in the water could result in much of the oil being submerged in the water column. Submerged oil can be suspended in the water column, suspended just above the river bed, or intermixed with sediment and trapped in the river bed and shoreline. In flowing waters, the spreading of the oil in three dimensions creates many challenges for responders to minimize the impacts of the release. Consideration of submerged oil in a flowing water environment would require different response action planning and response equipment to contain and recover the submerged oil. Dilbit intermixed with sediment and trapped in the river bed and shoreline results in a persistent source of oil and will present new response and recovery challenges. The understanding and adaptation of response and recovery techniques to Dilbit spills in flowing water scenarios continues along the Kalamazoo River in response to the 2010 Enbridge release near Marshall, Michigan. As the response to the Marshall Michigan Dilbit spill continues to mature and evolve, the lessons learned from the response and recovery efforts should be considered to facilitate the implementation of proper response planning and response strategies to improve the overall response to Dilbit spills." SEIS p. 4.13-60 (http://keystonepipeline-xl.state.gov/documents/organization/205621.pdf.). "Dilbit released into an aquatic environment could sink to the bottom of the water column and coat the benthic substrate and sediments. Dilbit intermixed

b. The State Department Needs to Address EPA's Concerns Regarding Impacts to Water Resources

EPA has expressed serious concerns over the original Keystone XL project and State's analysis of the impacts of this project throughout the NEPA process. The FEIS failed to adequately address many of EPA's concerns and the DSEIS continues this alarming trend. State must respond to EPA's concerns and also reconsider its previous responses to EPA's concerns in light of the new route and new information. State must also take a hard look at the impacts that it previously gave inadequate consideration to in order to correct the deficiencies of the previous analysis.

The following is a sampling of some of the concerns EPA raised and requests that have not been properly addressed.

- While the State Department looked at almost 750 areas where aquatic resources would be affected by pipeline construction and operations, it did "not identify impacts associated with ancillary facilities and connected actions, including staging areas, work camps and storage locations."[531]

- EPA recommended that "the USACE/EPA regulations that address compensatory mitigation for losses of aquatic resources be reviewed, and that compensatory mitigation consistent with these regulations…be developed that will adequately compensate for potential losses of wetland functions and services from pipeline construction and operation along the entire route be included in the revised Draft EIS."[532]

- EPA called for a thorough conceptual wetland monitoring plan.[533]

- EPA asked for additional information on the proposed widths of construction zones and right-of-ways for wetland crossings, along with a better explanation of which wetland areas would be revegetated, and which wetlands were considered to be of "special concern and value."[534]

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with sediment, trapped in the river bed or on an oiled shoreline would result in a persistent source of oil due to the slow rate of degradation of Dilbit in these environments. Dissolved components of the Dilbit such as benzene, PAHs, and heavy metals could be slowly released back to the water column for many years after the release. The dissolved components (e.g. benzene, PAHs, heavy metals) could allow for long term chronic toxicological impacts to many organisms (e.g. macro-invertebrates) in both the benthic and pelagic portions of the aquatic environment." Id. p.4.13-26.

[531] EPA DEIS Comment Letter at 6.
[532] *Id.* at 7.
[533] *Id.*at 7.
[534] *Id.*

- EPA requested more information on the total number of acres of forested wetlands disturbed by access roads and construction camps.[535]

- EPA noted that "equal mitigation commitments should be made for connected actions, including transmission lines."[536]

- EPA raised concerns about prairie pothole wetlands and bottomland hardwood forested wetlands and offered recommendations for how to minimize impacts to these resources.[537]

All of these comments have either been ignored or inadequately addressed. For example, the first comment in the list above asks State to look at impacts of ancillary facilities and related actions. Instead of actually giving the impacts of ancillary facilities and related actions a hard look, the DSEIS only mentions them in passing and attempts to pass off responsibility for protecting water resources to TransCanada and its contractors through a list of recommended mitigation measures. In discussing construction camps and how they may impact water resources, State says that "[w]aterbodies with habitats and species sensitive to or potentially impacted by flow reductions should be thoroughly analyzed to prevent adverse effects."[538] The DSEIS is the place where these impacts must be thoroughly analyzed: it is quite puzzling that State calls for a thorough analysis in the very document where that analysis is mandated to occur.

The fact that State has continued to not fully address the concerns raised by its sister agency, EPA, and that it calls for a mysterious future analysis to actually look at the impacts of this project are all strong indications it has not met its obligation to take a hard look at the proposed action and must now correct these deficiencies.

c. The Reroute Will Still Impact the Important Drinking Water Sources Such as Aquifers, Including the Ogallala

While impacts to the Ogallala Aquifer and the Sandhills were the primary reason for Keystone XL's reroute, the new route would not actually avoid these areas. Impacts to these precious resources have been paramount since this project was initially proposed and the new route still poses a risk to drinking water and aquifers.

The recent spill in Arkansas has illustrated the significant dangers of moving tar sands oil through drinking water source areas. As recently reported in the Wall Street Journal, Central Arkansas Water has recognized that while they had always been concerned about the risk this pipeline posed to the watershed, that the recent spill increased those concerns, and that "the only

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[535] *Id.* at 8.
[536] *Id.*
[537] *Id.* at 7.
[538] DSEIS, at 4.3-23.

way to completely eliminate the risk would be to move the pipeline further away."[539] The Arkansas Attorney General has raised concerns both about damages to groundwater and surface water, including lost revenue from tourists who visit Lake Conway.[540] The Pegasus pipeline passes through only 13 miles of this drinking watershed, a tiny area compared to the total mileage of drinking water source areas the proposed Keystone XL pipeline (which passes through four aquifers and within a mile of 2,537 wells[541] that provide water for millions of Americans), which has ten times the capacity of the Pegasus line, would pass through.

The reroute does not succeed in avoiding preventing the risk of impacts to the Ogallala Aquifer. According to TransCanada, "the Ogallala underlies most of the proposed re-route study area."[542] Approximately 35 miles of the proposed pipeline would cross over groundwater less than 20 feet below the surface.[543] The layers above the Ogallala Aquifer are highly permeable and spilled tar sands oil could move quickly through these layers into the aquifer itself, contaminating a crucial water source. The Ogallala Aquifer provides drinking water for millions of Americans and about 30% of the groundwater used for irrigation nationwide. It is clear that a tar sands oil spill above the Ogallala would be a serious issue and this new route does not succeed in avoiding this risk. If the proposed pipeline were to spill in this area and contaminate the Ogallala, it would be a catastrophe for the millions of Americans who rely on it for drinking and irrigation water every day. The State Department should provide a complete analysis of the spill risks to the Ogallala Aquifer rather than assuming special conditions will thwart potential problems.

In the draft SEIS, the State Department again fails to adequately analyze the impacts of this pipeline on aquifers and other drinking water sources. The reality is that existing evidence strongly indicates that tar sands pipelines spill more often than other pipelines and the impacts of catastrophic spills must be considered. Instead, much of the analysis relies on an assumption that significant spills won't happen. State continues to base its analysis on the 20 year old crude oil spill into the aquifer in Bemidji, Minnesota, failing to adequately consider how different a diluted bitumen spill would be.[544] One key difference is the increased risk of spill. Between 2007 and 2010, pipelines carrying tar sands oil in North Dakota, Minnesota, Wisconsin, and Michigan "spilled almost three times more crude oil per mile of pipeline when compared to the U.S. national average."[545] Oil spills have become frequent occurrences in Alberta, with three large

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[539] http://online.wsj.com/article/SB10001424127887324020504578398681691464660.html
[540] *Id.*
[541] DSEIS, at ES-10.
[542] https://ecmp.nebraska.gov/deq-seis/DisplayDoc.aspx?DocID=eInGtTzydRvDw10GNaJ4oA%3d%3d, TransCanada Keystone XL Pipeline Project: Initial Report Identifying Alternative and Preferred Corridors for Nebraska Reroute, at 14 (April 2012).
[543] http://articles.latimes.com/2012/apr/19/nation/la-na-nn-keystone-nebraska-20120419
[544] *See e.g.*, DSEIS, at 4.3-9.
[545] NRDC Report, Going in Reverse: The Tar Sands Threat to Central Canada and New England, at 6 (2012), *available at* http://www.nrdc.org/energy/files/Going-in-Reverse-report.pdf.

spills occurring just last month.[546] Moreover, as more is learned about these spills, it is increasingly apparent that current measures to detect, prevent and clean-up spills of diluted bitumen are grossly inadequate. These incidents have illustrated just how real the risk of a major spill is, but this analysis does not factor this in. Relying on the Bemidji spill for its frame means that State does not consider the massive volume of this pipeline, the increased pressure at which it will run, and the significant differences between diluted bitumen and conventional crude in performing its analysis of potential impacts to aquifers. As such, this analysis fails to take a hard look at the impacts of the proposed pipeline on aquifers.

d. New Information Necessitates New Analysis on the State of Water Resources

This analysis fails to include an adequate analysis of new information on the state of our nation's water resources. This failure includes, but is not limited to, the drought/record heat of 2012 and the reality that we are already living in a rapidly changing climate.

2012 was the warmest year on record in the United States and brought with it the worst drought in 24 years.[547] Over 1,000 U.S. counties declared natural disaster areas, farmers watched their crops wither in their fields, and wildfires are raged across the west. [548] As the predictions of climate change models come to fruition, water is becoming an increasingly precious resource, and rivers, wildlife, and the economy will all be adversely impacted. The consequences of an oil spill on water resources are magnified as we enter into an increasingly water limited era. State acknowledged many of the significant impacts on climate in the climate change section of the analysis,[549] but it fails to adequately consider the impacts of a changing climate on water resources. The science is clear that climate change will have impacts on both water quality and quantity. The impacts of this project must be considered in light of projections of increased water scarcity, drought, and changes in flow regimes. For example, increased drought and flooding incidents will necessitate increased measures to prevent spills in stream crossings because such events can bring about landslides, pipeline exposure, and other events that could cause damage to the pipeline.

The State Department must also consider new information on the causes and impacts of tar sand oil spills. This includes the NTSB's investigation into the 2010 tar sands oil spill near

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[546] Nathan Vanderklippe and Carrie Tait, *Third Oil Spill Fuels Calls for Alberta Pipeline Review*, The Globe and Mail, June 19, 2012, *available at* http://www.theglobeandmail.com/globe-investor/third-oil-spill-fuels-calls-for-alberta-pipeline-review/article4352760/.

[547] Moni Basu, Drought Stretches Across America, Threatens Crops, CNN, July 13, 2012 http://www.cnn.com/2012/07/13/us/midwest-drought/index.html

[548] *Id.*

[549] DSEIS, Section 4.14.

the Kalamazoo River,[550] all new information about the Mayflower spill, and new scientific studies regarding climate impacts on our nation's waters.

e. The DSEIS Wrongly Relies on the Nationwide Permitting Process

The CWA was enacted by Congress in 1972 to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters." 33 U.S.C. § 1251(a). To achieve this goal, §404 of the CWA prohibits the discharge of any pollutant, including dredged spoil or other fill material, into navigable waters unless authorized by the Army Corps of Engineers (the "Corps"). 33 U.S.C. § 1344.

Previous State Department analyses of impacts to water resources failed to properly account for impacts to waters and instead assumed such impacts would be accounted for in the Corps § 404 Clean Water Act permitting process. However, the State Department cannot simply pretend the Corps' permitting process will account for impacts to water resources. This is especially true given that the Corps' permitting process likely to be applied to this project does not comport with basic CWA requirements.

Before issuing a §404 permit for an individual project, the Corps must comply with guidelines promulgated by the U.S. Environmental Protection Agency ("EPA"), which are incorporated into the Corps' own regulations. *Id*. § 1344(b)(1); 33 C.F.R. §§ 320.4(b)(4) (2010), 325.2(a)(6) (2010). The Corps must ensure, *inter* alia, that there are no practicable alternatives to the proposed discharge of fill, that all appropriate steps have been taken to minimize potential adverse impacts, and that destruction of wetlands has been avoided to the extent practicable. 33 C.F.R. § 320.4(r); 40 C.F.R. § 230.10. When issuing an individual § 404 permit for a specific project, the Corps must comply with the requirements of NEPA.

As an alternative to the individual permit process, the CWA allows the Corps to issue Nationwide Permits ("NWPs") for categories of activities that "are similar in nature, will cause only minimal adverse environmental effects when performed separately, and will have only minimal cumulative adverse effect on the environment." 33 U.S.C. § 1344(e)(1). Projects permitted under a NWP do not undergo the same project-specific review required under the individual permit process.

It appears that the Corps is planning to permit impacts to waters from the proposed project under Nationwide Permit 12 (NWP 12).[551] NWP 12 allows utility projects with up to ½ acre of "loss of waters of the United States" to proceed without undergoing individual permit

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[550] NTSB Press Release, National Transportation Safety Board *Office of Public Affairs*, Pipeline Rupture and Oil Spill Accident Caused by Organizational Failures and Weak Regulations, July 10, 2012, http://www.ntsb.gov/news/2012/120710.html

[551] DSEIS, at 1.5-4 ("It is likely that most or all of the crossings in waters of the U.S. would be processed in accordance with the USACE general permit procedures, specifically Nationwide Permit (NWP) Number 12 for Utility Line Crossings.").

review. This it is inappropriate for this project to be permitted under NWP 12 and permitting the proposed project under NWP 12 means that basic CWA safeguards will not be properly applied.

The Corps' permitting of the Gulf Coast Pipeline under NWP 12 demonstrates the extent to which the public would be shut out of this process and the full host of impacts to U.S. waters would be ignored. The Corps' Tulsa, Fort Worth, and Galveston District offices all verified the Gulf Coast Pipeline under NWP 12 without sharing any information on impacts with the public, without providing any notice or opportunity for public comment, without performing any NEPA analysis, and without evaluating the project's cumulative impacts as required by the CWA. The Sierra Club and other groups filed a lawsuit charging violations of the Administrative Procedure Act (APA), NEPA, and Clean Water Act (CWA) in the Western District of Oklahoma.[552] That case is ongoing in both the district court and the 10th Circuit Court of Appeals.

Although NWPs are designed for projects with minimal individual and cumulative environmental impacts, NWP 12 contains a provision that allows the Corps to use it an unlimited number of times on a single pipeline project. Under NWP 12, the Corps has defined "single and complete project" so as to apply to each water crossing, thereby allowing large linear projects such as this one to "piecemeal a project into hundreds or even thousands of pieces to avoid individual permit review. For example, the Corps treated the Gulf Coast Pipeline's 2,227 water crossings as 2,227 separate "single and complete projects," which each fell under the ½-acre loss threshold. This is a blatant abuse of the NWP provision of the CWA.

Furthermore, the Corps' definition of "loss of the waters of the United States" excludes the "conversion" of forested wetlands to scrub shrub wetlands. Forested wetland conversion means that high-quality forested wetlands are destroyed and permanently prevented from growing back in the pipeline right-of way. Because this does not fall under the definition of "loss," NWP 12 permits *unlimited* conversion of high-quality forested wetlands to scrub-shrub wetlands. The NWP 12 Decision Document acknowledges that this conversion will be permanent and will result in loss of wetlands functions. This is an adverse environmental effect of the project that the State Department must analyze pursuant to NEPA.

Rather than analyze any of the specific impacts to U.S. waters, including but not limited to the extent of "loss" of U.S. waters, the wetland-specific impacts, and the "conversion" of forested wetlands,[553] the DSEIS defers the analysis to be completed in the 404 process:

> As noted in Sections 3.4.4 and 4.4.3, while the impacts presented in the Supplemental EIS may not be fully quantified at this time,

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[552] Amended Complaint for Declaratory and Injunctive Relief and Petition for Review of Agency Action, Sierra Club v. U.S. Army Corps of Engineers (W.D.Okla., June 29, 2012), Attached as Exhibit 109.
[553] The issue of whether the "conversion" of forested wetlands to scrub shrub wetlands is a "loss" is currently being litigated in the Gulf Coast Pipeline case.

> all existing wetlands would be accounted for during the Section 401 certification and Section 404 permitting process.[554]
> …
> The USACE Omaha District would be consulted to determine the kind of compensatory mitigation that would be required for losses of wetlands and water resources, including the permanent conversion of forested wetland to herbaceous wetland. USACE would determine eligibility for each wetland crossing under the nationwide and individual permit program. Preconstruction notification packages would include the mitigation plans agreed upon with the USACE…[555]
> …
> Potential wetland impacts would be evaluated during the environmental reviews for these projects and potential wetland impacts would be evaluated and avoided, minimized, or mitigated in accordance with direction from the appropriate USACE district offices.[556]

However, it is arbitrary and capricious for the DSEIS to defer this analysis because there is no guarantee that additional analysis will actually occur, as demonstrated in the case of the Gulf Coast Pipeline.

The same is occurring here. TransCanada may have already sought authorization from three U.S. Army Corps of Engineers districts to fill waters along the northern portion of the Keystone XL pipeline under NWP 12, but such information is being concealed from the public. The Sierra Club has filed a FOIA request to the Omaha district office seeking any Preconstruction Notifications (PCNs) that TransCanada has filed.[557] PHMSA notified the Sierra Club in a letter dated April 10, 2013 that was withholding two preliminary PCNs for South Dakota and Nebraska under the FOIA exemption "deliberative process."[558] Thus, all information on specific wetlands impacts of this project is being withheld from the public and is unlikely to be disclosed in any subsequent § 404 process. The public cannot meaningfully comment on the projects' impacts without that information. The State Department must disclose any and all project-specific impacts to wetlands in a subsequent draft EIS.

In short, permitting the northern segment under NWP 12 would be unlawful because it is highly controversial, would disturb more than one-half acre of non-tidal waters of the US, and

[554] DSEIS, at 4.4-2.
[555] *Id*. at 4.4-11 to 12.
[556] *Id.* at 4.4-14 to 15.
[557] Attached as Exhibit 110.
[558] Attached as Exhibit 111.

will cause an array of more than minimal impacts to the environment. [559] These include causing significant cumulative impacts that would be ignored under the NWP 12 permitting process, causing or contributing to violations of water quality standards, degrading of waters and adversely impacting human health and aquatic wildlife, potentially jeopardizing species protected under the Endangered Species Act, and causing permanent and significant impacts to forested wetlands.[560] Discharges from this proposed project should not be permitted under the NWP 12 process but rather should be subjected to the more comprehensive and transparent individual permitting process. Thus, any reliance the State Department places on Corps' permitting to protect water quality and habitat is misplaced and will fail to assess the likely impacts of this project on water resources.

f. State Must Provide Additional Analysis on Impacts to Wetlands and Streams

The DSEIS fails to provide in depth analysis of specific impacts to wetlands, instead focusing on promised future mitigation of both jurisdictional and non-jurisdictional wetlands.[561] The consideration of impacts to wetlands is both vague and unspecific, and relies heavily on the notion that Keystone officials will work with other entities to ensure that impacts are minimized. Commentators have raised this issue at all stages of NEPA analysis, yet this problem remains unremedied. This reliance on mitigation measures in the analysis violates both the Clean Water Act (CWA) and NEPA.

Under the CWA, discharges of pollutants, including dredged and fill material, are prohibited unless permitted pursuant to the Act.[562] In order for discharges of dredged and fill to be permitted under the Act by the U.S. Army Corps of Engineers (Corps or USACE), a "sequencing" analysis must occur.[563] First, impacts to wetlands must be avoided; then minimized; and finally, to the extent impacts are unavoidable, compensated.[564] For nonwater dependent projects, CWA regulations do not allow for a permit to be issued if a practicable alternative to the discharge exists that would have a lesser impact on aquatic water resources.[565] Mitigation is a last resort to be used only to compensate for impacts that could not be avoided or minimized. Yet this DSEIS relies almost entirely on mitigation measures in describing impacts to wetlands and streams, violating both NEPA and the CWA.

The DSEIS states that efforts will be made to avoid or minimize impacts to wetlands and streams. It fails to quantify the extent to which mitigation will be required, repeatedly stating that

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[559] *See* December 7, 2011 letter from NWF, Sierra Club, and NRDC to U.S. Army Corps of Engineers, Re: Clean Water Act Section 404 Permitting for the Keystone XL Pipeline, attached as Exhibit 112.
[560] *Id.*
[561] DSEIS, Section 4.4.
[562] 33 U.S.C. § 1311(a)
[563] 33 U.S.C. § 1344; 40 C.F.R. § 230.10(a)
[564] 33 U.S.C. § 1344(b)(1); 40 C.F.R. § 230.10(a)
[565] 40 C.F.R. § 230.10(a)

this analysis will happen in the future. "While acreages presented in tables may not be fully quantified at this time, they would be accounted for during the subsequent federal and state permitting process."[566] This is unacceptable. The purpose of this document is to disclose environmental impacts, but the document itself fails to do so.

13. <u>The State Department Fails to Analyze the Reasonably Foreseeable Impacts Associated with TransCanada's Reapplication for a PHMSA Special Permit</u>

The DSEIS is deficient because it fails to adequately consider the reasonably foreseeable scenario in which TransCanada increases the operating capacity and pressure of the Keystone XL Pipeline.

In 2008, TransCanada applied to PHMSA for a special permit waiver pursuant to 49 C.F.R. § 195.106. The special permit would have allowed TransCanada to operate at a higher maximum operating pressure (MOP) than normally permitted under the regulation. The current regulation requires a standard design factor of .72 and TransCanada requested a special permit to operate the pipeline at a design factor of .80. This would have enabled TransCanada to reduce capital costs by building Keystone XL using a thinner-than-normal steel.[567] Under this scenario, Keystone XL would have a maximum operating capacity of 900,000 barrels per day and would operate at a pressure of 1,400 psig.[568] It would also incorporate 57 special conditions designed to mitigate the increased risk of spills from this higher operating pressure.

Sierra Club, WORC, the Pipeline Safety Trust, and other groups submitted comments on the proposed special permit.[569]

In response to public concern over the special permit, TransCanada withdrew its special permit application on August 5, 2010.[570] Upon withdrawal of its special permit application, TransCanada did not announce that it would build Keystone XL using standard thickness pipe, thereby obviating the need for a special permit. To the contrary, TransCanada announced that it would proceed with building the pipeline using the thinner-walled pipe and would continue to implement the 57 safety conditions. Thus, the proposed maximum operating capacity was reduced to 830,000 bpd to attain an allowable operating pressure of 1,308 psig.[571] By using the thinner pipe in its construction and incorporating these conditions, TransCanada is ready and able to reapply for the special permit waiver in the future as soon as the increased operating pressure and 900,000 bpd capacity become necessary.

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[566] DSEIS, at 4.4-6.
[567] *See* attached comments of the Pipeline Safety Trust, at 1 (attached as Exhibit 113). The comments of Sierra Club and WORC are also attached as Exhibits 114 and 115.
[568] FEIS, at 2-1 to 2-2.
[569] *See*, Exhibits 113, 114, and 115.
[570] TransCanada Press Release, August 5, 2010, available at http://www.transcanada.com/5443.html.
[571] DSEIS, at 1.2-1 and 2.1-36.

In its press release announcing the withdrawal of its special permit, TransCanada made no secret of these plans to reapply for the special permit waiver in the future at a time when opposition has faded:

> The company recognizes it needs to take more steps to assure the public and stakeholders that the parameters of the special permit would result in a safer pipeline. The company will continue to establish an operating record which will demonstrate the strength and integrity of the Keystone Pipeline System, which has been granted a special permit. *Keystone XL will implement the additional safety measures that would have been required under the special permit. These measures offer an enhanced level of safety and would allow TransCanada to request a special permit in the future.* [572]

Recently-released correspondence between State Department staff and TransCanada lobbyists confirm that TransCanada plans to reapply for the special permit after public scrutiny has been reduced. In a July 26, 2010 email from TransCanada's Paul Elliot ("Elliott") to the State Department's Marja Verloop ("Verloop"), Elliott explains:

> TransCanada has concluded that until there is better information in the public domain on the engineering safety of such pipe design and operation we won't to (sic) operate KXL at a higher pressure. This decision will mean lower volumes of oil moving to refineries of the Gulf Coast.[573]

On the same day, Verloop responded by asking:

> I take it withdrawing the request does not preclude TCPL from re-submitting in the future?[574]

Elliot answered later that day:

> You are correct, in withdrawing our request for a special permit at this time, allows TransCanada to submit a request for a special permit at a later date. The process for consideration would start from scratch and include an environmental assessment done by PHMSA.[575]

Furthermore, the Office of Inspector General's (OIG) 2011 report on the State Department's review of Keystone XL states, "TransCanada withdrew its special permit application from the Pipeline Hazardous Materials Safety Administration, hoping to change

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[572] *See*, fn. 570.
[573] FOIA excerpts re PHMSA, at 1 (attached as Exhibit 116).
[574] *Id*.
[575] *Id*.; *see also* http://www.washingtonpost.com/business/economy/keystone-pipeline-e-mails-show-friendly-exchanges/2011/10/02/gIQAXzRdHL_story.html

public opinion and focus on the Presidential permit application."[576] The report goes on to note, "TransCanada withdrew its special permit application, knowing that it could reapply for a special permit later."[577]

Thus, TransCanada's withdrawal of its special permit waiver was a tactical decision designed simply to defer analysis of the controversial pressure waiver until a later date. The withdrawal did not cause TransCanada to change anything regarding its operation. Even with the special permit, Keystone XL's design would have entailed operating at a lower initial capacity and slowly increasing capacity over several years.[578] The 2011 FEIS indicated that the proposed pipeline would have an initial capacity of 700,000 bpd, but "could transport up to 830,000 bpd of crude oil by adding pumping capacity if warranted by future market demand."[579] TransCanada has since increased the proposed initial capacity for Keystone XL to the maximum capacity of 830,000 bpd in its current application for a Presidential Permit.[580]

In view of the circumstances set out above, the potential impacts resulting from TransCanada's reapplication for a special permit from PHMSA should have been analyzed in the DSEIS in accordance with NEPA. A proper cumulative impacts analysis must evaluate "the impact on the environment which results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (Federal or non-Federal) or person undertakes such actions."[581]

TransCanada's resubmission of a special permit application absolutely qualifies as a reasonably foreseeable future action and must be treated as such in the State Department's analysis of Keystone XL. The DSEIS fails to even acknowledge TransCanada's submission and subsequent withdrawal of its application for a PHMSA special permit. It merely states:

> A special permit would be required from PHMSA if the pipeline were to operate using a higher design factor. In this situation, PHMSA permit conditions would provide an equivalent or better level of safety.[582]

The reference to a higher design factor equates to a higher operating pressure and hence, a larger capacity.[583] The DSEIS wrongfully defers to the environmental assessment that would be conducted by PHMSA should TransCanada resubmit its application for a special permit. Because this scenario is a reasonably foreseeable future action, the State Department must

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[576] OIG Report, at 28.
[577] *Id.*, at 29.
[578] EnSys Keystone XL Assessment, Final Report (Dec. 23, 2010). (p.25)
[579] FEIS, at 2-1.
[580] TransCanada Application, at 16.
[581] 40 C.F.R. § 1508.7
[582] DSEIS, at 2.1-36.
[583] See, internal design pressure equation at 49 C.F.R. § 195.106

perform its own analysis of the potential impacts resulting from increased operating pressure and capacity, rather than relying on future assessments to be conducted by another agency.

The State Department should evaluate the project using the reasonably foreseeable capacity of 900,000 bpd rather than the initial capacity of 830,000 bpd. The environmental impacts and safety risks associated with operating a diluted bitumen pipeline at a higher-than-recommended pressure must be considered.

14. The DSEIS Fails to Consider that Approval of Keystone XL Would Result in a Violation of the Energy Independence and Security Act

NEPA regulations require the State Department to analyze "whether the action threatens a violation of Federal, State, or local law or requirements imposed for the protection of the environment." 40 C.F.R. § 1508.27. If approved, the Keystone XL pipeline would lead directly to violations of Section 526 of the Energy Independence and Security Act of 2007 ("EISA"), 42 U.S.C. § 17142, which provides:

> No Federal agency shall enter into a contract for procurement of an alternative or synthetic fuel, including a fuel produced from nonconventional petroleum sources, for any mobility-related uses, other than for research or testing, unless the contract specifies that the lifecycle greenhouse gas emissions associated with the production and combustion the fuel supplied under the contract must, on an ongoing basis, be less than or equal to such emissions from the equivalent conventional fuel produced from conventional petroleum sources.

Reducing greenhouse gas emissions of the federal government is an important purpose of EISA, because these emissions contribute directly to climate change. As the U.S. Supreme Court has concluded, "[t]he harms associated with climate change are serious and well recognized." *Massachusetts v. EPA*, 549 U.S. 497, 521 (2007).

Section 526 applies to federal agency contracts for procurement of "an alternative or synthetic fuel, including a fuel produced from nonconventional petroleum sources." 42 U.S.C. § 17142. However, federal agencies have routinely avoided compliance with Section 526 by using the following reasoning: tar sands crude oil is transported to various known refineries throughout the country; agencies routinely purchase refined products from these specific refineries; however, because the contracts are for "generally available fuel" without regard to the source, they are not required to comply with Section 526.

For example, the largest purchaser of fuel within the federal government is the Department of Defense (DOD). The Defense Logistics Agency (DLA) is the entity within DOD that handles all fuel purchases. In 2009, DLA Energy published its "Interim Implementation Plan Regarding Section 526 of [the EISA]" ("Implementation Plan") to implement its policy of noncompliance with Section 526.[584] The Implementation Plan acknowledges that it routinely purchases fuel from U.S. refineries that process heavier tar sands crude oil.[585] DLA also concedes that its contracts do not include the specification required under Section 526.

DLA reasons, however, that it need not comply with Section 526 as long as its contracts are vaguely written so as not to specify any particular source of the procured oil. It reasons, "so long as DLA Energy does not target or specify oil sands as the source of crude and so long as the fuels are commercially available, then these products should be considered outside the purview of Section 526."[586]

The Implementation Plan further explains that "because it is almost impossible to purchase fuel which contains no Canadian oil sands as its crude source, attempting to exclude oil sands crude from purchases of refined products would increase costs and compromise readiness by eliminating needed sources of supply."[587] In other words, federal agencies do not comply with Section 526 because tar sands crude oil is part of the "generally available" fuel supply, and they claim it would be too difficult to separate tar sands crude from conventional crude oil.

Therefore, because agencies refuse to follow the plain language of Section 526 when they enter into fuel procurement contracts, the State Department must consider compliance with Section 536 before approving significant new infrastructure projects that would supply tar sands-derived fuel to the federal agencies, such as Keystone XL. Keystone XL would supply tar sands crude oil to several refineries that are known to sell finished petroleum products to government agencies, including but not limited to the Valero refineries in Corpus Christi and Texas City, Texas and the Shell refinery in Deer Park, Texas.

The DSEIS includes a comparison of GHG emissions from various sources of crude oil, and estimates that tar sands crude oil would lead to 17% more GHG emissions compared to the US average. See Appendix W, Table 4-12. Thus, finished products supplied to U.S. refineries via Keystone XL would be ineligible for purchase by government agencies. Furthermore, agencies such as DOD have made clear that they do not comply with Section 526 at the time of purchasing these fuels.

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[584] Attached as Exhibit 117; see also LMI, attached as Exhibit 118.
[585] LMI Report, at 6-3.These include, but are not limited to: BP-Husky in Lima, Ohio; BP in Whiting, Indiana; BP West in Ferndale, Washington; ChevTex in Salt Lake City, Utah; Conoco-Phillips in Ponca City, Oklahoma; ConocoPhillips in Oklahoma City, Oklahoma; ExxonMobil in Baton Rouge, Louisiana; ExxonMobil in Baton Rouge, Louisiana; Gary Williams in Wynnewood, Oklahoma; Hunt in Tuscaloosa, Alabama; Shell in Deer Park, Texas; Shell in Martinez, California; Sinclair in Sinclair, Wyoming; Tesoro in Aiea, Hawaii; United Refining in Warren, Pennsylvania; U.S. Oil Refining in Tacoma, Washington; Valero in Benicia, California; Valero in Corpus Christi, Texas; and Valero in Texas City, TX.
[586] Implementation Plan, at 8.
[587] *Id*. at 8-9.

The State Department must consider whether, and to what extent, an approval of Keystone XL would result in government purchases of tar sands fuel in violation of Section 526. It has failed to do so.

15. <u>The U.S. Bureau of Land Management Approval Process for Keystone XL Does Not Meet Legal Requirements</u>

a. The U.S. Bureau of Land Cannot Rely on a Deficient DSEIS to Process Rights-of-Way and Temporary Use Permits

The U.S. Bureau of Land Management is responsible for issuing rights-of-way (ROW) grants for all federal lands under the Mineral Leasing Act (MLA) of 1920 and the public lands BLM administers under the Federal Land Policy and Management Act (FLPMA) of 1976 affected by the proposed project.[588] ROWs are issued for long-term, permanent activities, such as pipeline and related facilities, such as pipeline and pump station operations, as well as for temporary use during construction and other short-term project related actions.[589] In assessing ROW permit applications, the BLM must ensure compliance with land use plans and all federal, state and local laws and ordinances.[590] Significantly, "BLM has responsibility for the designation and protection of sensitive species on BLM managed lands that require special management consideration to promote their conservation and reduce the likelihood and need for future listing under the ESA."[591] As such, BLM must analyze the impacts to resources, including sensitive species and habitat, affected by the proposed project. The DSEIS indicates that BLM will use the State Department's Presidential NEPA analysis as the "basis for issuing their Record Decision" of TransCanada's pending ROW applications.[592] In doing so, BLM is equally responsible for the sufficiency of the DSEIS and, conversely, ensuring that the DSEIS incorporates adequate information to ensure ROW compliance with all relevant laws and regulations.

As an initial matter, the undersigned have not been able to obtain TransCanada's pending ROW applications despite a regulation requiring BLM to issue a "statement of where the application and related documents are available for review."[593] In reviewing a ROW application, the applicant also must "submit a plan of construction, operation, and rehabilitation for such right-of-way or permit."[594] The BLM website providing information on pending major rights-of-way grants fails to include TransCanada's ROW application; the existing internet links send the public to the State Department's Keystone XL website, and to 2009 Federal Register notices for

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588 DSEIS, at 1.3-3.
589 30 U.S.C. § 185
590 43 CFR § 2884.21
591 DSEIS, at 4.8-23.
592 *Id.* at 1.3-3.
593 43 CFR 2884.20 (a)(2).
594 30 U.S.C § 185(h)(2).

the first proposed Keystone XL project and related DEIS. Those links provide notice of public hearings from the 2010 public participation process.[595]

The MLA governs ROWs and temporary use permits issued for pipelines transporting oil and other synthetic and gaseous fuels, or any refined product.[596] Of particular relevance is the requirement that BLM ensure pipeline safety to protect workers and the public "from sudden ruptures and slow degradation of the pipeline."[597] In addition, BLM must ensure compliance with NEPA and implement additional environmental protection measures:

> The Secretary … prior to granting a right-of-way or permit … for a new project which may have a significant impact on the environment, require the applicant to submit a plan construction, operation, and rehabilitation for such right-of-way … which shall comply with this section. The Secretary … shall issue regulations or impose stipulations which shall include, but shall not be limited to: (A) requirements for restoration, revegetation, and curtailment of erosion of the surface of the land; (B) requirements to insure that activities in connection with the right-of-way or permit will not violate applicable air and water quality standards … (C) requirements designed to control or prevent (i) damage to the environment (including damage to fish and wildlife habitat), (ii) damage to public or private property, and (iii) hazards to public health and safety; and (D) requirements to protect interests of individuals living in the general area of the right-of-way or permit who rely on the fish, wildlife, and biotic resources of the area for subsistence purposes

30 U.S.C § 185(h).

BLM also must ensure compliance with relevant regulatory provisions, including requirements for public notification and hearings and for completion of a NEPA analysis and for statutory and regulatory consistency determinations. 43 CFR §§ 2884.20, 2884.21, 2885.11.

BLM may deny a ROW application if:

> [t]he proposed use is inconsistent with the purpose for which BLM or other Federal agencies manage the lands … the proposed use would not be in the public interest … issuing the grant or TUP would be inconsistent with the Act, other laws, or these or other regulations …cannot demonstrate the technical or financial capability to construct the pipeline or operate facilities within the right-of-way or TUP area …

43 CFR §§ 2884.23.

The proposed Keystone XL pipeline would cross 45 miles of federal land under management and jurisdiction of the BLM, and all of these federal lands are in the state of

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[595] *See*, http://www.blm.gov/mt/st/en/prog/lands_realty/projects.html#Keystone.
[596] 30 U.S.C § 185(a).
[597] 30 U.S.C § 185(g).

Montana. DSEIS 2.1-87. As such, BLM also must ensure that ROWs are consistent with the relevant Resource Management Plans (RMP): the Big Dry (April 1996); the Powder River (March 1985); and the Judith Valley Phillips.[598]

The DSEIS is deficient because it fails to ensure that the quality of air, water/wetland and wildlife resources are either maintained or improved, especially in "areas of critical environmental concern" (ACEC) and for Montana "designated species of concern" as required by the relevant RMPs. By relying on the DSEIS for processing ROWs and temporary use permits, BLM fails to meet its statutory and regulatory requirements set out above. Specifically, there are numerous federally threatened and endangered species in Montana, and species of concern designated by the state that will be adversely impacted by the pipeline and the associated ROW. These species include the black-footed ferret, greater sage grouse[599], black-tailed prairie dog, interior least tern[600], mountain plover[601], piping plover, Sprague's pipit[602], whooping crane, and pallid sturgeon, among others. The ROW would result in habitat destruction and fragmentation, direct species mortality, and harm to species' critical life functions such as reproduction, nesting and foraging. DSEIS 4.8-1. As described in detail in section II.D.10-11,

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[598] See RMPs, found at: http://www.blm.gov/mt/st/en/prog/planning/big_dry.html; http://www.blm.gov/mt/st/en/prog/planning/JVP.html; http://www.blm.gov/mt/st/en/prog/planning/powder_river.html. Without seeing TransCanada's ROW application it is difficult to determine to what degree the ROW falls within a particular ACEC. Nonetheless, the pipeline will cross sensitive ecosystems for which the SDEIS has not adequately assessed impacts. See DSEIS, at 4.8.1-34. *See* comments on wildlife, water/wetlands, Sections II.D.11-13, *supra*.

[599] "Approximately 190 miles of the proposed pipeline route extend through areas with greater sagegrouse habitat in Montana (MFWP 2001). Of this distance, 94 miles are classified as moderate to high-quality habitat for greater sage-grouse, and 96 miles are classified as marginal habitat for greater sage-grouse. Ground-verification surveys of habitats found that the proposed pipeline route would cross only 35.9 miles of suitable habitat, of which half of this area was considered high-quality habitat." DSEIS, at 4.8-6-7.

[600] Yellowstone and Missouri Rivers serve as foraging and nesting habitat for the interior least tern. DSEIS, at 4.8-11-12.

[601] Mountain plovers make their breeding grounds in Montana. DSEIS 4.8-24

[602] "The proposed Project may cause grassland habitat loss, alteration, and fragmentation; loss of eggs or young during construction; and facilitated raptor predation from power poles from associated power lines" DSEIS 4.8-13-14. The construction of electrical distribution lines would incrementally increase the collision and predation hazards for breeding Sprague's pipits in the proposed Project area. The power distribution line to proposed Pump Station 10 would cross 18.6 miles of the North Valley Grasslands important bird area (IBA) and may impact survival and reproduction for ground nesting grassland birds; the same line would cross 2.1 miles of the Charles M. Russell National Wildlife Refuge IBA, which supports 15 birds of global conservation concern (Montana Audubon 2008). Both of these IBAs support breeding Sprague's pipits. Construction of these distribution lines during the breeding season could potentially disturb nesting and brood-rearing birds. Power lines across native grassland habitats may contribute to fragmentation." DSEIS, at 4.8-38-39.

supra, the DSEIS fails to adequately assess and mitigate impacts to species, many of which would be harmed by the activities for which the ROW would be permitted.

Among other omissions described throughout these comments, the DSEIS fails to incorporate review of a completed spill Emergency Response Plan (ERP), rendering the DSEIS, and thus BLM's ROW assessment, deficient. *See* detailed discussion at Section II.D.4. Knowledge of TransCanada's spill response capabilities and estimates of worst case spill scenarios are key factors in assessing the magnitude of impacts on species and in developing mitigation measures to reduce harm. Indeed, the BLM has a duty to ensure pipeline safety and to "impose requirements for the operation of the pipeline and related facilities" to protect worker safety and the public from "sudden ruptures and slow degradation of the pipeline." 30 U.S.C § 185(g).

As proposed, the Keystone XL will cross the Missouri and Yellowstone Rivers, which serve as important habitat for several federally listed species and Montana designated species of concern, including the interior least tern and the pallid sturgeon. In the last few years, the Yellowstone River endured a significant pipeline spill unleashing 42,000 gallons of oil that spread 240 miles. Further, clean-up continues to be underway for the 820,000 gallon spill into Michigan's Kalamazoo River three years ago and the recent Pegasus Pipeline spill in Arkansas. There were 14 unanticipated spills during the Keystone I's first year of operation. These facts, alone dictate the need for a fully assessed ERP.

Absent completion of an ERP that considers the impacts of a worst case spill and considers the cumulative impacts and lessons learned from previous spills, the agency and the public cannot fully analyze the impacts of the proposed project. Nonetheless, it appears that the State Department, and thus BLM, has impermissibly deferred completion and review of the ERP until PHMSA issues a permit for pipeline operation. Appendix I of the DSEIS provides only a draft of spill response measures that would be implemented during construction and reclamation only, but does not address spill response measures during pipeline operation. Elsewhere, the DSEIS includes TransCanada's unsubstantiated claims about its spill response capability, and vague recommendations for improved agency oversight, buried in generic oil spill information that says nothing about TransCanada's actual plans or capacity, including spill response equipment or personnel. DSEIS Section 4.13.

Indeed, PHMSA's requirement to review the ERP does not waive other agencies' NEPA review requirements. The agencies cannot overlook this critical piece of the NEPA analysis. Absent a complete and fully assessed ERP, the DSEIS is deficient, thereby rendering BLM's ROW assessment inadequate and in violation of NEPA, MLA, its regulations, and relevant resource management plans.

b. BLM's Deferral of ROW Grants for "Connected Actions" Renders the DSEIS Inadequate

As an additional matter, it appears that BLM has deferred processing of ROWs for electrical transmission and distribution lines[603] that will power the pipeline and related facilities, such as pump stations, until after the State Department's national interest determination and presidential permitting processes are complete. Indeed, transmission lines that power the Keystone XL are "connected actions" under NEPA. NEPA requires "connected actions" "to be considered together in a single EIS." *Thomas v. Peterson*, 753 F.2d 754, 758 (9th Cir.1985). And, NEPA regulations define "connected actions" as actions that are "closely related and therefore should be discussed in the same impact statement."[604] BLM's processing of transmission line ROWs subsequent to State's presidential permitting process renders the DSEIS insufficient. At present, the FEIS contemplates potential impacts from transmission and distribution lines that are currently proposed but for which no power company has submitted a ROW application. While these impacts would be significant,[605] they cannot be fully analyzed until the electrical power provider submits its ROW application describing the final plans for transmission construction and operation.

c. BLM Must Extract Compensation for the Rights of Way

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[603] FLPMA governs the issuance of ROWs for electrical transmission lines on federal lands. 43 U.S.C. §1761; 43 CFR § 2801.9 (a)(4).

[604] 40 C.F.R. § 1508.25(a)(1)(1978). "Connected actions" are those that i) automatically trigger other actions which may require environmental impact statements; ii) cannot or will not proceed unless other actions are taken previously or simultaneously; and iii) are interdependent parts of a larger action and depend on the larger actions for their justification. *Klamath-Siskiyou Wildlands Center v. Bureau of Land Management*, 387 F.3d 989, 998 (9th Cir. 2004) ("Proposals or parts of proposals which are related to each other closely enough to be, in effect, a single course of action shall be evaluated in a single impact statement."); *Wetlands Action Network v. U.S. Army Corps of Engineers*, 222 F.3d 1105, 1118 (9th Cir. 2000) (the requirement to analyze connected action prevents an agency from "dividing a project into multiple actions, each of which individually has an insignificant environmental impact, but which collectively have a substantial impact").

[605] "Electrical distribution lines associated with the proposed Project are collision hazards to migrant whooping cranes. The construction of new electrical distribution lines, especially those across riverine or wetland roosting habitats (Yellowstone River in Montana, Missouri River in South Dakota, and Platte River in Nebraska) or between roosting habitat and nearby feeding habitat (including wetlands and grain fields), would incrementally increase the collision hazard for migrating whooping cranes because a portion of the proposed Project area is located within the primary migration corridor for this species. The Platte River electrical distribution line crossing is within the primary migration corridor for whooping cranes, and the Yellowstone and Missouri river electrical distribution line crossings are on the western edge. An analysis of suitable migration stop-over habitat (e.g., large waterbodies, wetlands, and associated agricultural fields) during migration, in relation to preliminary electrical distribution line routes, identified multiple locations within the primary migration corridor for 19 pump stations where electrical distribution lines could potentially increase collision hazards for migrating whooping cranes. Keystone would inform electrical power providers of the requirement to consult with the USFWS for the electrical infrastructure components constructed for the proposed Project to prevent impacts to the whooping crane." DSEIS 4.8-39.

BLM has not extracted any form of reimbursement from TransCanada for the rights-of-way. 30 U.S.C. 185(l) states:

> The applicant for a right-of-way or permit shall reimburse the United States for administrative and other costs incurred in processing the application, and the holder of a right-of-way or permit shall reimburse the United States for the costs incurred in monitoring the construction, operation, maintenance, and termination of an pipeline and related facilities on such right-of-way or permit area and shall pay annually in advance the fair market rental value of the right-of-way or permit, as determined by the Secretary or agency head.

There is no indication in the DSEIS that BLM has required TransCanada to reimburse the United States, or if they have, what the amounts of reimbursements are. Thus, there is no way for the public to determine whether the reimbursements are fairly compensating taxpayers. BLM must remedy this omission in any subsequent environmental analysis.

d. BLM Must Disclose TransCanada Shareholders

Finally, as part of its duties under the MLA, BLM must require TransCanada to supply the identity of the corporation's shareholders. Specifically, 30 U.S.C. § 185(i) requires the applicant to disclose:

(1) The name address of each partner
(2) The name and address of each shareholder owning 3 per centum or more of the shares, together with the number and percentage of any class of voting shares of the entity which such shareholder is authorized to vote, and
(3) The name and address of each affiliate of the entity together with, in the case of an affiliate controlled by the entity, the number of shares and the percentage of any class of voting stock of that affiliate owned, directly or indirectly, by that entity, and, in the case of an affiliate which controls that entity, the number of shares and the percentage of any class of voting stock of that entity owned, directly or indirectly, by the affiliate.

BLM must fulfill its statutory duty to obtain critical shareholder information about TransCanada before making its ROW determination. BLM's determination to issue a ROW grant or temporary use permit must be based on complete information and a transparent record. Shareholder disclosure is a critical component to ensuring that the review and permitting process is transparent and without conflicts of interest.

The DSEIS does not appear to include this information, and commenter Sierra Club has sent requests to multiple BLM officials to supply TransCanada shareholder identities required by MLA. BLM issued a response to Sierra Club's request conveying that the request will be treated as a FOIA request and provided an approximate response date of July 2, 2013, well after the close of public comment A failure to obtain this information would render BLM's ROW grants for the proposed project invalid.

III. <u>TRIBAL CONCERNS</u>

This DSEIS evidences a failure of State to adhere to its duties to tribes. Specifically, it has failed to properly consult with tribes on the proposed project, consider impacts to irreplaceable cultural resources, and give a hard look at the impacts of the proposed pipeline to tribal water resources. Please see National Wildlife Federation's (NWF) comments on tribal impacts for a fuller and more detailed analysis of these failures.

A. TRIBAL CONSULTATION

1. <u>The State Department Has an Obligation to Properly Consult with Tribes</u>

Native American tribes occupy a unique legal status, with certain rights established in the U.S. Constitution, treaties, Executive Orders, and by the judiciary. The federal government's trust obligation to tribes requires it to act in the best interest of Native American tribes and individuals. In addition, tribes have the right to government-to-government consultation with the federal government. This requirement is set forth in Executive Order 13175, Consultation and Coordination with Indian Tribal Governments (EO 13175).[606] Section 5(a) of EO 13175 states that "[e]ach agency shall have an accountable process to ensure meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications."

2. <u>The State Department's Consultations Were Inadequate</u>

The DSEIS claims that the Department has consulted and continues to consult with tribes regarding this proposed project. However, the Department's tribal consultation process fails to fulfill the spirit of consultation as envisioned under EO 13175. Instead of leading to meaningful government-to-government consultation with all potentially impacted and interested tribes, it appears that the Department has engaged in a rote exercise designed to check off bare minimum legal requirements for tribal consultation. We reiterate the comments NWF provided to the Department on July 26, 2012 and July 30, 2012, reaffirmed during conference calls with the State Department on June 21, 2012 and September 4, 2012, and also submitted as a separate letter during this comment period regarding State's failure to adequately consult with tribes.

[606] Executive Order No. 13,175, 65 *Fed. Reg.* 67249 (November 9, 2000). EO 13175 expanded the breadth of tribal consultation to "ensure the meaningful and timely input by tribal officials in the development of regulatory policies [rules, policies, and guidance] that have tribal implications." Tribal implications are defined as having substantial direct effects on one or more tribes, on the relationship between the federal government and tribes, or on the distribution of power and responsibilities between the federal government and tribes. Among other things, EO 13175 requires federal agencies to respect tribal self-government and sovereignty, honor tribal treaty and other rights, and strive to meet responsibilities arising from the unique relationship between the federal government and tribes.

State also failed to develop and implement an accountable consultation plan and failed to conduct meaningful government-to-government consultation with tribes. State's tribal consultation efforts consisted of the following measures, which in effect replicated its previous inadequate consultation efforts during the preparation of the FEIS:

a. State claims it contacted tribes that had previously expressed an interest in engaging in the consultation process or whose interests had not been expressed. However, it excluded tribes that declined to engage in the last round of analysis. For the final EIS, State reached out to 95 tribes and tribal groups, but not all of them wanted to be involved at that time. The DSEIS concerns a new area so State should have, at a minimum, re-contacted all 95 tribal entities. However, State only contacted 80, effectively abrogating its responsibility to the 15 other tribes that may now, for whatever reason, want to engage.

b. State has stated that it made follow-up phone calls and sent e-mails to tribes to determine their interest in consultation regarding the Pipeline. However, it does not specify to whom these calls and emails were addressed. Were they sent only to tribes who indicated an interest in consultation? Were the proper people contacted? Did State have an up to date contact list at the tribe? Did it reach out to multiple entities at each tribe in case some were unavailable at that time? Finally, what was the content of these phone calls and e-mails? Was it adequate for tribes to understand that this might be their only chance to engage in consultation on this massive project?

c. In October 2012, State held three consultation meetings with tribes in Montana, South Dakota, and Nebraska. The process and content of those meetings raises significant questions. For example, it does not appear that there were opportunities for individual tribes to meet with State: these were more of public meetings attended by multiple tribes. Additionally, significant questions remain on whether all tribes interested in consultation were there or were only the ones able to afford the travel and staffing costs of sending someone to those meetings present.

d. The DSEIS says "additional government-to-government consultation is underway for the current Supplemental EIS process for the proposed Project."[607] State should have completed consultation prior to completing the DSEIS so it could make sure that tribal concerns were given the requisite hard look in this document.

3. <u>Recommendations</u>

The Department must develop and implement an accountable tribal consultation plan that is widely available to tribes both affected and potentially affected by the Pipeline. State's current consultation plan, "Plan to Implement Executive Order 13175: *Consultation and Coordination*

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[607] DSEIS, at 1.6-1.

with Indian Tribal Governments," is short on specifics on the process and its implementation. Furthermore, the Programmatic Agreement[608] is problematic because tribes were merely granted "concurring party" status so they do not retain the same rights as signatory parties to amend or terminate the agreement. This gives them a significantly lower status and disqualifies them from receiving compensation for project impacts. Tribes should have equal rights to all other parties to the Programmatic Agreement. These are significant threshold issues.

In addition to raising these major issues, we offer the following specific recommendations on how the Department could conduct effective consultation with tribes:

a. Develop guidance on how the Department intends to assure that consultation meetings result in meaningful dialogue rather than simply pro forma consultation.

b. Assign a tribal liaison with significant experience working with tribes on major construction projects.

c. Provide adequate time to tribes to review and provide comments. The 30- to 60-day comment periods are wholly inadequate for tribal entities to be able to properly respond to massive documents requiring substantial analysis.

d. Send a letter to all tribal chairs with copies provided to staff (*e.g.*, tribal administrator, environmental manager) that asks how the tribe would like to be consulted with. Providing copies to various individuals of authority within the tribe provides better assurances that the tribe will be made aware of the opportunity to consult. Asking the tribe how it would like to be consulted respects its preferences and tribal culture, and helps to insure that true government-to-government consultation occurs.

e. Assure tribes that the most senior-level Department officials will be engaged in consultation with them. This is the proper procedure to follow because tribes will likely be represented by their highest-level officials in consultation processes.

f. Keep the channels of communication open throughout the consultation process.

g. Inform tribal leaders, representatives and members about the proposed project and its potential impacts. The Department should ensure that community members receive information about the proposed project and its impacts because tribal leaders often rely on input from them to make decisions.

h. Do not rely solely on written communications and telephone conversations. Group meetings, direct mailings, teleconferencing, direct telephone communications, and email may not be sufficient to engage particular tribes. State should hold in-person,

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[608] DSEIS at Appendix S.

face-to-face meetings with tribal representatives. State should also be prepared to accept oral comments from tribes in the place of or in addition to written comments.

i. Stop mistaking group meetings with tribes as true government-to-government consultation as called for by EO 13175. State's group meetings with tribes are not consultation but informal informational meetings and are only a first step in the Department's engagement with tribes in government-to-government consultation.

One on one consultation provides opportunity for candid conversations between individual tribes and State that may not occur during a group meeting. Because most cultural resources information is confidential and is protected from release, discussion of such information at a group meeting risks its release to the general public and potentially endangers tribal cultural sites and practices. Thus tribes may not raise significant issues in public venues.

B. CULTURAL RESOURCES

1. The State Department Has an Obligation to Protect Tribal Cultural Resources

The Department and cooperating federal agencies are legally and ethically obligated to protect and preserve tribal historic and cultural resources.[609] This responsibility is established by the federal government's trust responsibility; the U.S. Constitution; treaties; and several federal statutes, executive orders, presidential memoranda, secretarial orders, memoranda of understanding, and department and agency policies. This DSEIS provides the U.S. government with an opportunity to put words to action by promoting better stewardship and protection of Native American cultural resources and sacred sites.

2. Tribal Cultural Resources Are Threatened by This Project

The proposed Pipeline route and area of potential effect (APE)[610] cross lands that have been occupied, utilized, and revered by Native Americans since time immemorial. The APE encompasses a relatively high concentration of pre-contact period cultural resources as well as objects, sites, and places that are vital to the continuing traditional, cultural, spiritual, and religious practices of Native Americans. Section 3.11.3.1 of the DSEIS notes that "[l]ands and resources within and outside the respective Native American reservations are important to Native

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[609] Executive Order No. 13007, 61 Fed. Reg. 26771 (May 29, 1996). ("In managing Federal lands, each executive branch agency … shall, to the extent practicable, permitted by law, and not clearly inconsistent with essential agency functions, (1) accommodate access to and ceremonial use of Indian sacred sites by Indian religious practitioners and (2) avoid adversely affecting the physical integrity of such sacred sites.").

[610] The area of potential effect is defined as the "geographic area or areas within which an undertaking may directly or indirectly cause alterations in the character or use of historic properties, if any such properties exist." DSEIS, at 3.11.3.2, *citing* 36 CFR § 800.16(d)).

American peoples for subsistence gathering, collection of plants for medicines, spiritual and ceremonial purpose, and everyday life." Recognizing the truth of this statement, it now seems unreasonable that a pipeline could be permitted to adversely impact these lands and resources.

One example of impacted land is the portion of the Pipeline that crosses the area of the Great Sioux Nation that was reserved under the 1851 and 1868 Fort Laramie Treaties. The Sioux tribes that signed these treaties have aboriginal rights to cultural, historical, and burial sites that may be located in and around the Pipeline APE[611] and that could be affected by the widening of roads, trenching of the site, and oil spills.[612]

3. State Has Failed to Complete an Adequate Cultural Resources Analysis

While it appears that State, TransCanada and its contractors have attempted to identify cultural resources within the APE (DSEIS § 3.11.3.3), the cultural resources analysis is deficient, a troubling fact at this late stage of project planning. NEPA and the National Historic Preservation Act (NHPA) require agencies to assess potential resource impacts at the earliest possible time to insure that planning and decisions reflect environmental values, to avoid delays in the process, and to head off potential conflicts.[613] State has been analyzing the proposed Pipeline for years, yet it has failed to complete a full analysis of the potential effects to tribal and cultural resources. It would be unlawful for this project to move forward until all impacts have been studied and subject to review and comment by tribes and the public, consistent with NEPA and NHPA regulations.

Cultural resources, once altered, damaged or destroyed, are irreplaceable. Moreover, it is nearly impossible to remove cultural resources from their surrounding environment without infringing on the traditional, cultural, or religious significance of such resources. Indeed, the DSEIS states that "[a]voidance is recommended for all eligible or unevaluated sites."[614] Mitigation and avoidance should not be limited to NRHP-listed or eligible resources. The Unanticipated Discovery Plan and Tribal Monitoring Plan, mentioned briefly in the DSEIS, should be finalized before the Pipeline is approved. Additionally, the DSEIS is flawed for the following reasons:

a. Incomplete Resource Data: The Department does not have complete data on the cultural resources that may be impacted, a fact acknowledged in the DSEIS.[615] The

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[611] *See* Rosebud Sioux Tribe, Resolution No. 2011-308 and Resolution #758-2010-05, Fort Beck Assiniboine and Sioux.
[612] TransCanada's earlier project, the Keystone I tar sands crude oil pipeline through the Great Plains ruptured at least 14 times during its first year of operation (2010-2011), spewing toxic sludge.
[613] *See e.g.*, 40 C.F.R. § 1501.2
[614] DSEIS, at 3.11.3.3 (pp. 3.11-13, 3.11-20, 3.11-26). See also DSEIS, at 3.11.2.2 (All known cultural resources "will be avoided.")
[615] DSEIS, at 3.11.3.2 ("…[cultural resource] surveys are ongoing…." DSEIS at 3.11.3.3. ("All route modifications…have been *or will be* surveyed.", "[T]he following areas remain unsurveyed….")

reasons for this deficiency are unfinished survey efforts and inadequate tribal consultation. According to the DSEIS, at least 8,500 acres of the APE have not been surveyed for cultural resources. In addition, the Department has not properly carried out tribal consultation, as explained above, and has thus failed to ensure that all potentially impacted and interested tribes have the opportunity to provide cultural resource information. Thus State cannot possibly have a full set of data on the cultural resources that may be impacted.

This is especially true with respect to the Pipeline route and APE through Nebraska. The Nebraska DEQ prepared the environmental impact analysis (including cultural resources) for this segment of the proposed project.[616] However, State prohibited Nebraska DEQ from consulting with tribes. Therefore, Nebraska DEQ received no tribal input in preparing its cultural resource analysis. State may not abrogate its myriad responsibilities to Nebraska tribes by relying on the incomplete analysis provided by Nebraska DEQ.

b. Pending NRHP Eligibility Determinations: According to the DSEIS, more than 150 identified cultural resources have not been or will not be evaluated from NRHP eligibility. NRHP eligibility should be determined for all cultural resources in the APE before the final DSEIS is released.

c. Lack of Assessment of Potential Effects: The Department must explain the potential effects to cultural resources.[617] Nowhere in the DSEIS does the Department discuss potential effects to cultural resources located in the proposed project APE. Which of the listed resources is most likely to be impacted during construction? What are the potential impacts (i.e. physical destruction, alteration, removal, change of character)?

d. Lack of Mitigation: A complete impacts analysis must include a determination of the mitigation measures that will be used to avoid, reduce, or mitigate the impacts predicted in the analysis.[618] The DSEIS does not even mention a mitigation plan for cultural resources. Unanticipated Discovery Plans have not been prepared as required by NHPA, the Native American Graves Protection and Repatriation Act, and the Historical

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[616] *See* Memorandum of Understanding Between U.S. State Department and the Nebraska Department of Environmental Quality for Conducting an Environmental Review for the Keystone XL Pipeline Project (May 2012), *available at* http://keystonepipeline-xl.state.gov/documents/organization/191054.pdf.
[617] 36 C.F.R. § 800.5 ("the agency official shall apply the criteria of adverse effect to historic properties within the area of potential effects").
[618] 36 C.F.R. § 800.6 ("The agency official shall … develop and evaluate alternatives or modifications to the undertaking that could avoid, minimize, or mitigate adverse effects on historic properties.") See also 40 C.F.R. § 1508.25 ("Scope consists of the range of actions, alternatives, and impacts to be considered in an environmental impact statement.")

and Archaeological Data Preservation Act.[619] State must finalize these plans before it releases the final DSEIS.

C. STATE HAS FAILED TO ADEQUATELY PROTECT TRIBAL WATER RESOURCES

In earlier KXL comments, we indicated that Pipeline would cross water pipeline easements owned and operated by the Oglala Sioux Tribe for the Mni Wiconi Project.[620] This tribe has not given permission to TransCanada to have the Pipeline cross over the water pipeline easements.[621] Further, Ordinance No. 85-72 of the Oglala Sioux Tribe Oil and Gas Regulations prohibits the unauthorized transportation of oil through tribal lands. Using the water pipeline easements for the Pipeline oil would trespass on tribal and fee lands.[622]

We now understand that there may be some dispute as to whether the Pipeline will cross tribal easements. Nevertheless, the Oglala Sioux Tribe has a genuine concern about any adverse effect that the Pipeline could have on the Mni Wiconi Project, such as the contamination of water, which brings surface water from the Missouri River to the Pine Ridge Indian Reservation. On particularly troubling issue is that the DSEIS does not even account for the number of times that the Keystone XL Pipeline would cross the Mni Wiconi water pipelines. State must provide this information. Further, because it has a trust responsibility to ensure that adequate and safe water supplies are available to meet the economic, environmental, and public health needs of tribes, State must take every precaution to protect the Oglala Sioux and other tribes served by the Mni Wiconi Project, even if it means redirecting the Pipeline away from that site.

D. THE DSEIS FAILS TO COMPLY WITH ALL APPLICABLE RULES, REGULATIONS, AND EXECUTIVE ORDERS

The DSEIS provides that the Department will comply with the NHPA and its implementing regulations. However, there are a number of other laws, Executive Orders, and Presidential Memoranda with which the Department must comply but that were not covered, or

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[619] *See* NWF's Draft SEIS Comments on Tribal Concerns, Appendix A, for a complete listing of relevant statutory authorities.

[620] The Mni Wiconi Project Act of 1988, Pub. L. 100-516, as amended, authorized the Mni Wiconi Project to deliver safe water to the Pine Ridge Reservation, the Rosebud Indian Reservation, Lower Brule Indian Reservation, and the area known as West River/Lyman-Jones.

[621] According to 25 C.F.R. § 169.3(a), "[n]o right-of-way shall be granted over and across any tribal land, nor shall any permission to survey be issued with respect to any such lands, without the prior written consent of the tribe."

[622] Resolution of the Executive Committee of the Oglala Sioux Tribe (An Unincorporated Tribe) (Resolution No. 11-165XB) Directing the Oglala Sioux Rural Water Supply System, Bureau of Reclamation and Morrison and Maierle to Immediately Cease and Desist any Negotiation Sand Plans with the TransCanada's Keystone XL Pipeline Officials to Construct the Keystone XL Pipeline across the Mni Wiconi Water Pipeline Easement.

at least not sufficiently, in the DSEIS. These legal requirements are listed in NWF's detailed tribal comments.

It is also crucial to note that the Department's responsibility does not begin nor does it end with these laws, Executive Orders, and Presidential Memoranda. It must also honor its trust responsibility to tribes with respect to the Pipeline project to insure that its actions and those of others do not adversely affect the cultural resources or practices of such tribes. As such, we urge the Department to act expeditiously to protect tribal interests in this process.

IV. KEYSTONE XL WOULD NOT SERVE THE NATIONAL INTEREST

A. THE DSEIS FAILS TO ADDRESS ITS STATED FACTORS NECESSARY TO MAKE ITS NATIONAL INTEREST DETERMINATION

The DSEIS states the State Department's Purpose and Need as follows:

> The Department's purpose, therefore, is to consider Keystone's application in terms of how the proposed Project would serve the national interest taking into account the proposed Project's potential environmental, cultural, economic, and other impacts.[623]

Some of the key factors that the DSEIS says it will take into account in considering whether the pipeline would serve the national interest are:

- Environmental impacts of the proposed Project;
- Impacts of the proposed Project on the diversity of supply and security of transport pathways for crude oil imported to the United States;
- Impact of a cross-border facility on the relations with the country to which it connects;
- Stability of various foreign suppliers of crude oil and the ability of the United States to work with those countries to meet overall environmental and energy security goals;
- Impact of proposed projects on broader foreign policy objectives, including a comprehensive strategy to address climate change, bilateral relations with neighboring countries; and energy security;
- Economic benefits to the United States of constructing and operating the proposed Project; and
- Relationships between the proposed Project and goals to reduce reliance on fossil fuels and to increase use of alternative and renewable energy sources."[624]

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[623] DSEIS, at 1.3-2.
[624] *Id.* at 1.3-2 to 3.

The DSEIS does not include a discussion of all of these factors that were expressly included in the Purpose and Need as necessary for the State Department to make its decision on whether the project would serve the national interest.

B. THE DSEIS FAILS TO DISCUSS EXPORTS IN TERMS OF WHETHER THE PROJECT WOULD SERVE THE NATIONAL INTEREST

The Purpose and Need of State's NEPA analysis is:

> "…to consider Keystone's application in terms of how the proposed Project would serve the national interest taking into account the proposed Project's potential environmental, cultural, economic, and other impacts."[625]

The SDEIS specifically states that a key factor of that analysis is: "Stability of various foreign suppliers of crude oil and the ability of the United States to work with those countries to meet overall environmental and energy security goals;"[626]

The State Department discusses the booming petroleum product export trade from Gulf Coast refineries potentially served by the Project only in terms of its effect on refinery demand in light of declining domestic demand. "The combined effect of these demand, export, and refining factors is that, although the demand outlook has changed, the refining outlook is similar."[627]

The Department fails to assess whether the Project's connection to the country's leading export refineries is in the national interest. The role of the Project in meeting the environmental and energy security goals of the United States is substantively undermined by the fact that the majority of the products refined from the crude oil delivered by the Project will be exported.

The DSEIS notes most of the products produced at Gulf Coast refineries today are exported. "However, almost half of PADD 3 refined products go to the domestic market."[628]

With declining domestic demand and the prospect of a continuing low cost advantage for Gulf Coast refiners for the foreseeable future, the proportion of product refined at these refineries is only likely to increase.

It is no longer the case that these refineries predominately export products that play a minor role in the U.S. economy such as residual fuel oil and petroleum coke. In 2012, the Texas

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[625] *Id.* at 1.3-2.
[626] *Id.*
[627] *Id.* at 1.4-14.
[628] *Id.* at 1.4-15.

Gulf Coast refineries exported 60 percent of their gasoline production, some 278,000 barrels per day.[629]

It is a fact that the refineries the Project will connect to, such as Valero refineries in Texas, are the leading export refineries in the country, while others such as Motiva and Phillips66 in Lake Charles, Louisiana, have announced their intension to increase their export trade.[630] These companies regard Canadian bitumen blends as a low cost option for supplying these refineries, so the connection between the Project and the future profitability of these refineries and their export trade is clear.

The State Department must assess the Project's role in these exports in light of the energy security and environmental goals of the United States. It makes little sense for the administration to be implementing efficiency measures in one part of the economy (namely the vehicle fleet), while another part of the economy simply transfers the emissions saved by those policies to foreign markets. As CO_2 causes climate forcing wherever it is emitted, the export of petroleum products produced by U.S. refineries is the export of emissions that otherwise would have been mitigated in the U.S. economy through efficiency progress.

The DSEIS asserts throughout the Market Analysis that global oil demand will follow a certain trajectory based on EIA Reference Case forecasts and that therefore supply will meet that demand regardless of whether the Project is built. This not only ignores the influence of increased supply on demand as governed by basic economic principles, but also fatalistically accepts a trajectory of oil supply and demand that dooms the planet to catastrophic levels of climate change.[631] The acceptance of such a scenario is not only counter to society's interest but is counter to current U.S. government policy.

The DSEIS also fails to adequately assess the possibility of crude exports from the Project by focusing solely on the possibility of bitumen blend exports. This ignores the emerging evidence that, at least while West Coast pipelines remain a distant prospect, exports of SCO via the U.S. Gulf Coast could be profitable.[632] This drastically changes the analysis of the Project's impact on U.S. energy security, as well as the project's influence on tar sands production with regard to U.S. refinery demand.

Rising production of North American tight oil is in direct competition with SCO because it is of similar quality, being of low density and containing very little sulfur. It is therefore valuable to refiners worldwide that have not invested in equipment to refine lower quality heavy

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[629] Oil Change International "Keystone XL refineries already exporting 60 percent of their gasoline." March 2013. http://priceofoil.org/wp-content/uploads/2013/03/OCI.Keystone-XL-refineries-export-60-percent-gasoline-March-2013-FIN3.pdf
[630] Oil Change International, March 2013.
[631] See Greenhouse Gas section.
[632] Citi, "Energy 2020: Independence Day - Global Ripple Effects of the North American Energy Revolution" February 2013. https://www.citivelocity.com/citigps/ReportSeries.action page 38

oil. Competition from tight oil in the North American market is likely to see SCO discounted against other light sweet crudes in the mid-continent. But delivery of SCO to the Gulf Coast is unlikely to improve returns by much as the Gulf Coast market is set to become flooded with crude to the extent that the discounts seen in recent years in the midcontinent could shift to the Gulf Coast.[633] This improves the economics for European refiners to import Canadian SCO from the Gulf Coast as the discount could still leave room for transatlantic transport costs. Citi also notes that in 2015, when the Panama Canal expansion opens and lowers costs for very large crude carriers (VLCCs) to travel from the U.S. Gulf Coast to Asia, exports of SCO to Asia could also be possible.[634] As the SEIS notes, there is no legal barrier to exporting Canadian oil through the U.S. if the oil has not comingled with domestic oil.[635]

The State Department must reassess the potential and scale of both crude and refined product exports from the Project and weigh these against the environmental and energy security goals of the United States.

C. THE DSEIS DOES NOT ADEQUATELY DISCUSS EMPOLOYMENT AND ECONOMIC BENEFITS

The Purpose and Need further states that the DSEIS must discuss the "[e]conomic benefits to the United States of constructing and operating the proposed Project" in order to assess whether the project would serve that national interest. The DSEIS fails to adequately do so. To the extent that it does, the DSEIS suggests that the project would not serve the national interest.

For example, the DSEIS states that largest economic impacts of the project would come during construction, and that approximately 3,900 temporary construction jobs would be created.[636] However, the DSEIS acknowledges that only 35 to 50 permanent jobs necessary for the pipeline operation would be created, some of which would be in Canada, and concludes that "the employment and earnings impacts in the United States stemming from operations of the proposed Project would be negligible."[637]

D. KEYSTONE XL WOULD NOT SERVE OUR NATIONAL CLIMATE REDUCTION GOALS

The Purpose and Need further states that the DSEIS must explore "[r]elationships between the proposed Project and goals to reduce reliance on fossil fuels and to increase use of alternative and renewable energy sources" in order to assess whether the project would serve that national

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[633] Citi, February 2013, page 40.
[634] *Id.* at page 50.
[635] DSEIS, at 1.4-17.
[636] *Id.* at 4.10-5.
[637] *Id.* at 4.10-24.

interest. The DSEIS fails to adequately do so. To the extent that it does, the DSEIS suggests that the project would not serve the national interest.

The United States has clear commitments to the American public and the international community to lead in the global transition to a low-carbon economy. As an Annex I Party to the UN Framework Convention on Climate Change ("UNFCCC"), the United States is obligated under Article 4.2(a) to adopt national policies and take corresponding measures to mitigate climate change that will demonstrate it is "taking the lead in modifying longer-term trends in anthropogenic emissions consistent with the objective of the Convention."[638] As such, the United States must show progress towards achieving the UNFCCC's ultimate objective of stabilizing global greenhouse gas concentrations at a level that would prevent dangerous human interference with the climate system.[639] The United States has also made a political commitment to accelerate the transition to a "clean energy, green economy," which is critical to protecting our national interests in energy security and independence.[640]

The Keystone XL project would contribute to substantial increases in greenhouse gas emissions and thus would have significant global climate impacts. Extraction, upgrading, transportation and refining of tar sands oil is extremely energy and greenhouse gas-intensive. The draft SEIS life-cycle analysis demonstrates that WCBS crude oil emits 17% more GHGs than crude oil refined in the United States (as of 2005).[641] Additionally, as described above, there are several ways in which the life-cycle analysis fails to adequately account for project emissions, including not taking into account emissions associated with expansion of the tar sands. This means that total emissions from the project are likely to be far greater than those estimated in the draft SEIS. Thus, Keystone XL is contrary to the United States' obligations and commitments to lead the international community in taking urgent action to mitigate climate change. The project would also undermine key U.S. policy priorities in transitioning to a clean energy economy.

E. KEYSTONE XL WOULD PROLONG OUR RELIANCE ON OIL

America is often said, *e.g.*, by President Barack Obama and former President George W. Bush, to be addicted to oil. Like addicts, we persist on using oil even though it hurts us in many ways. Oil is a leading source of smog, particulate matter and other toxic pollution that

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638 UNFCCC, Art. 4.2(a).

639 For more extensive analysis, *see* Center for International Environmental Law, Earthjustice, and Greenpeace USA, *Public Comments on the National Interest Determination of the Proposed Keystone XL Pipeline* (Oct. 2011), http://www.ciel.org/Publications/KeystoneXL_Comments_7Oct11.pdf.

640 In March 2010, the President Obama introduced the administration's comprehensive energy security strategy stating that, "for the sake of our planet and our energy independence, we need to begin the transition to cleaner fuels now." The White House, "Remarks by The President on Energy Security at Andrews Air Force Base," March 31, 2010, *available at* http://www.whitehouse.gov/the-press-office/remarks-president-energy-security-andrews-air-force-base-3312010.

641 DSEIS, Executive Summary, Section ES.5.5.2.

contributes to tens of thousands of deaths each year. Our addiction leads to oil spills in our rivers and oceans, poisoning our drinking water sources, polluting our communities and destroying fragile ecosystems. Breaking an addiction is a wrenching process. Alternatives already exist for most uses of oil, and adopting these options while making a persistent effort to slow fossil fuel expansion will improve our lives in many ways beyond slowing climate change.

The Keystone XL Pipeline is *not* in the national interest because it delays the transition to cleaner fuels. It will promote further development and importation of tar sands crude into the United States, thus perpetuating the *status quo* dependence of our nation on oil, hindering the investment, research and development of alternative sources of energy, that are produced right at home. These alternative sources in the transportation sector include electric vehicles, and in the power generation sector include wind and solar. These alternative sources are cleaner than tar sands derived fuels in terms of life-cycle greenhouse gas emissions and emission of pollutants, hence they are far preferable environmentally to tar sands oil. They are also more economical considering the hidden costs of tar sands oil, such as increased local and global environmental effects, including greenhouse gases, black carbon, and its impact on the Arctic, destruction of the Canadian boreal forests and potential spills, to name a few. Transitioning away from fossil fuels towards, clean sustainable sources of energy also is in the national interest economically since it can create millions of new jobs developing alternative sources of energy that are clean and domestically produced. The State Department must evaluate an alternative that determines whether it is in the national interest to transition away from fossil fuels, and tar sands oil in particular, to cleaner sources of energy to avoid the negative effects of continued dependence upon oil.

The U.S. already has begun to lead on efforts to stem our nation's oil dependence and reduce national greenhouse gas emissions. Approving the Keystone XL pipeline would be counterproductive to these efforts, as it will pave the way for increased tar sands extraction and consumption. On the other hand, if the U.S. denies the proposed project and ramps up investments in cleaner fuels produced right at home, it will facilitate growth of clean fuels and help to create global demand for them. The DSEIS does not take a critical look at ambitious new federal policies that are forcing significant investment in clean fuels development, and ignores the fact that the U.S., and specifically this Presidential Permit decision, is critical to maintaining a clear path toward clean fuel solutions. The people of Canada have halted efforts to build pipelines and additional refineries to get this dirty fuel to market. The U.S. also must recognize that another pipeline will perpetuate this country's dependence on oil and undermine the national interest.

CONCLUSION

We look forward to the opportunity to provide further comments on the State Department's next environmental impact statement for the proposed project, as well as comments on the State Department's determination as to whether the Keystone XL would serve the national interest.

Ultimately, we urge the State Department to find that the Keystone XL pipeline would not serve the national interest and reject TransCanada's Presidential Permit application. Thank you for the opportunity to provide comments on this important matter.

If you have any questions about these comments, please contact me at 303-449-5595 ext. 100.

Respectfully submitted,

_/s/Doug Hayes__

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Appendix I

Report evaluating the adequacy of the Keystone XL (KXL) Draft Supplemental Environmental Impact Statement (DSEIS) Market Analysis

Report evaluating the adequacy of the Keystone XL (KXL) Draft Supplemental Environmental Impact Statement (DSEIS) Market Analysis

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April 22, 2013

Table of Contents

1. Executive Summary

In reviewing the adequacy of Keystone XL (KXL) Draft Supplemental Environmental Impact Statement (DSEIS), the TGG Report has focused on the evaluation of the main conclusion of the DSEIS Market Analysis. The Market Analysis has concluded that KXL will not have a substantial impact on tar sand production and expansion. In response, this Report seeks to answer the following question:

"Did the DSEIS Market Analysis substantially underestimate the impact that a rejection of KXL would have on tar sands production and expansion through 2030 across a number of scenarios?"

The TGG Report answers this question with an unequivocal yes.

Based on our evaluation of current market conditions (including emerging crude markets, factors driving tar sands expansion, availability and cost of crude oil transportation, and tar sands breakeven costs),the TGG Report concludes that the Market Analysis is deeply flawed and not a sound basis for decision-making. We have determined that KXL, and specifically its impact on tar sands logistics costs and crude prices, will have a significant impact on tar sands expansion under a very broad range of conditions and assumptions.

The precise impact of KXL is difficult to quantify and would require a highly sophisticated analysis that examines a range of scenarios and many interactive effects (to model the dynamic market conditions that exist in the real world petroleum markets). However, for the purposes of providing practical guidance to policymakers, a conservative and credible estimate would be that KXL's effect on tar sands expansion would be 100% or 1:1. In other words, every barrel of tar sands crude transported by KXL would be the equivalent of a barrel of expanded crude production in the tar sands. Therefore, if at full capacity, KXL can transport 830,000 bpd of tar sands crudes, then its effect on tar sands expansion would be 830,000 bpd.

To undertake our evaluation of the DSEIS Market Analysis on which the TGG Report conclusions (and impact estimate) are based, we first outlined the key elements of the Market Analysis that drive the DSEIS conclusion (i.e. that KXL will not have a substantial impact on tar sand production and expansion) in Section 3).

In the subsequent Sections (Sections 4, 5, and 6), we focused on the following areas relating to tar sands market conditions: Crude Markets, Availability and Cost of Crude Oil Transportation, and Tar Sands Expansion and Breakeven Costs. For each of these areas, we examined the assumptions and methodology of key elements of the Market Analysis. In each of the focus areas (which corresponds to a separate section), the TGG Report determined that the assumptions and methodology of key elements of the Market Analysis were flawed and not a sound basis for decision-making. Furthermore, each of these sections supports the TGG

Report's key finding that KXL will have a significant impact on tar sands expansion under a very broad range of conditions and assumptions.

The TGG Report's Crude Markets analysis (Section 4) evaluates the DSEIS Market Analysis in the context of the rapid and dramatic shifts currently underway in the North American oil system. TGG compares the DSEIS analysis with information from a number of sources and determines that the DSEIS analysis is not properly reflective of emerging market conditions. As part of our analysis in this Section, TGG examined (i) US crude production; (ii) competition between different crudes; (iii) capital investment and operating decisions that shift the crude slate; and (iv) foreign refinery ownership issues affecting Canadian tar sands. TGG concludes that (a) the emerging and dynamic conditions in the crude markets may become increasingly challenging for tar sands producers; (b) the DSEIS Market report uses lagging data and does not adequately take into account how changes in the crude markets are likely to result in more challenging economic conditions for tar sands producers. Under challenging economic conditions, it is even more essential for tar sands producers to have access to high volume, low cost logistics. Therefore the approval of KXL will have a significant impact as an enabler of less profitable marginal tar sands projects that could not be constructed without access to low cost logistics.

TGG's review of the Availability and Cost of Crude Oil Transportation (Section 5) demonstrates serious impediments to both pipeline expansion and crude by rail. TGG therefore rejects the key Market Analysis assumption that pipeline and other transport/takeaway capacity will not be a significant constraint on tar sands. Our evaluation concludes definitively that pipelines are by far the preferred transportation option because of low costs and high capacity. However, it is clear that the tar sands are currently pipeline-constrained. Section 5.2 concludes that in light of increasing public opposition, there are uncertain prospects for all of the major proposed pipeline projects to transport tar sands crude. Section 5.3 then undertakes a detailed review of the DSEIS assumption that crude by rail can be implemented at a sufficient scale and speed to transport all incremental tar sands production to markets, even absent new pipeline capacity. This Section demonstrates the deep flaws in the DSEIS assumption regarding crude to rail. In fact, contrary to the assumptions of the Market Analysis, our evaluation concludes that crude by rail is a not well matched for the transport of tar sands crude in terms of both cost effectiveness and risk factors.

Section 5 evaluates and rejects the two flawed and related DSEIS assumptions discussed above (i.e. that (a) pipeline and other transport/takeaway capacity will not be a significant constraint on tar sands expansion; and (b) crude by rail can be implemented at a sufficient scale and speed to transport all incremental tar sands production to markets, even absent new pipeline capacity). These two assumptions are among the most significant drivers for the DSEIS conclusion that KXL will not have a substantial impact on tar sand production and expansion. And both assumptions are deeply flawed. As such TGG devoted significant effort in Section 5 to demonstrate the uncertain prospects for all of the major proposed pipeline projects to transport tar sands crude. It was then necessary to examine the validity of the Market Analysis' second significant assumption: that other logistics (notably crude by rail) can be implemented at a sufficient scale and speed to transport all incremental tar sands production to markets, even absent new pipeline capacity. Section 5.3 undertakes an extensive review of the current and prospective use of crude by rail as a viable large-scale transportation option for tar sands crude. TGG concludes that crude by rail is not well matched for the large-scale transport of tar sands crude, both in terms of cost-effectiveness and risk factors. In demonstrating that there are serious impediments to other tar sands crude transportation options (including other pipelines and crude by rail), Section 5 makes a strong case that the approval of KXL matters - and it matters a great deal - for tar sands expansion.

Section 6 provides an appropriate framework for analyzing tar sands expansion and breakeven costs. The Market Analysis assumes that most tar sands projects will likely have breakeven costs that are low relative to likely crude pricing, such that these projects will still be profitable with higher logistics costs. In Section 6.2, the TGG report explores the important issue of how changes in logistics costs and crude prices affect the amount of tar sands expansion. We conclude that the following framework is a reasonable basis for analysis and decision-making:

1) Across a very broad range of conditions and assumptions, changes in logistics costs and crude prices will impact the amount of tar sands expansion.

2) KXL, and specifically its impact on tar sands logistics costs and crude prices, will thus impact the amount of tar sands expansion.

Sections 6.3 and 6.4 demonstrate how different market dynamics affect the relationship between crude prices and tar sands expansion costs. In a context where logistics are constrained (and potentially subject to major opposition and delays), a high rate of tar sands expansion (likely accompanying high crude prices) could result in higher effective logistics costs. In contrast, a lower rate of tar sands expansion (likely accompanying low crude prices) could result in lower effective logistics costs. However, generally lower crude prices are not favorable for tar sands profitability and expansion.

These dynamics matter in terms of how KXL could have an impact on tar sands expansion. At high crude prices, access to a low-cost, high-capacity transportation option could facilitate maximum tar sands expansion since part of the constraint of higher logistic costs would be removed. At low crude prices, access to a low-cost, high-capacity transportation option could enable some of the less profitable marginal tar sands projects. Therefore across a broad range of conditions (high crude prices and high logistics costs to low crude prices and low logistics costs), KXL can enable tar sands expansion (at low crude prices and low-cost logistics) or maximize tar sands expansion (at high crude prices and high-cost logistics).

Tar sands breakeven costs are examined in Section 6.5 and the Market Analysis data is compared to other more recent data sources. Our evaluation shows that the DSEIS is relying on outdated information that substantially underestimates the breakeven costs for tar sands projects under emerging market conditions. As indicated above, under challenging economic conditions, it is even more essential for tar sands producers to have access to high volume, low cost logistics. Approval of KXL will have a significant impact as an enabler of less profitable marginal tar sands projects that could not be constructed without access to low-cost logistics.

Based the evaluation of current market conditions in the TGG Report, Section 7 concludes the following:

3) The DSEIS Market Analysis is deeply flawed and not a sound basis for decision-making.

4) KXL, and specifically its impact on tar sands logistics costs and crude prices will have a significant impact on tar sands expansion under a very broad range of conditions and assumptions.

5) The exact quantification of the impact of KXL requires a sophisticated analysis that is beyond the scope of this report. However, for purposes of providing practical guidance to policymakers, a conservative and credible estimate would be that KXL's effect on tar sands expansion would be 100% or 1:1. In other words, every barrel of tar sands crude transported by KXL would be the equivalent of a barrel of expanded crude production in the tar sands.

6) Should policymakers wish to base their decision on a more sophisticated and detailed analysis, we suggest that the evaluation from the TGG Report be used as input for such an analysis, which would also address and remedy the deep flaws identified in the DSEIS Market Analysis.

2. Introduction

This Report evaluates the adequacy of the Keystone XL (KXL) Draft Supplemental Environmental Impact Statement (DSEIS).[1] Specifically, this Report reviews and responds to the DSEIS Market Analysis (Section 1.4). The DSEIS Market Analysis relies, in part, on information provided in other sections of the DSEIS. Thus, this Report also reviews and responds to information provided elsewhere in the DSEIS, notably Market Analysis Supplemental Information (Appendix C), and No Action Alternative (Section 2.2.3, and specifically information relating to crude by rail).

This Report was prepared by The Goodman Group, Ltd. (TGG), a consulting firm specializing in energy and regulatory economics.[2] This project was partially supported with funding from Natural Resources Defense Council (NRDC) and the Sierra Club.[3] Any findings, conclusions or opinions are those of TGG and the authors and do not necessarily reflect those of NRDC and/or the Sierra Club.

In evaluating complex energy issues, TGG's orientation is to undertake a deep and comprehensive analysis of the relevant economic and other issues. But the KXL DSEIS Market Analysis touches upon a very wide range of issues, such that a full independent analysis and extensive consideration of relevant context is simply impractical for TGG to undertake given the limited time, information, and other resources available. In light of these constraints, TGG has provided a sound alternative analysis that offers useful guidance to policymakers. In particular, the alternative analysis provided in this report provides more useful guidance than does the flawed Market Analysis in regard to whether KXL will substantially impact tar sands expansion. Based on guidance from our alternative analysis (and other input received as part of comment process), the EIS preparers should now revise the Market Analysis in order to provide a sound basis for decision-making.

In reviewing the adequacy of the Market Analysis, TGG was particularly focused on evaluating its main conclusion: that KXL will not have a substantial impact on tar sands production and expansion. To undertake this evaluation, we first outlined the key elements of the Market Analysis that drive this main conclusion (Section 3). In the subsequent sections (Sections 4-6),

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[1] http://keystonepipeline-xl.state.gov/draftseis/index.htm

[2] www.thegoodman.com This Report was co-authored by Ian Goodman and Brigid Rowan, co-authors (with the Cornell Global Labor Institute) of a previous report regarding KXL: Pipe Dreams? Jobs Gained, Jobs Lost by the Construction of Keystone XL.

[3] The issues regarding KXL are of great importance and have been the subject of wide public concern in the US, Canada, and elsewhere. In preparation of this report, the authors undertook substantial work in addition to that supported with funding from NRDC and the Sierra Club. This additional work is provided as a public service to assist in consideration of the important issues regarding KXL.

we examined the assumptions and methodology of key elements of the Market Analysis relating to Crude Markets (Section 4), Availability and Cost of Crude Oil Transportation (Section 5) and Tar Sands Expansion and Breakeven Costs (Section 6).

Section 4 contrasts the Market Analysis consideration of emerging market conditions with data from a number of sources and demonstrates that the DSEIS market outlook is not properly reflective of emerging market conditions. TGG concludes that emerging and dynamic conditions in the crude markets may become increasingly challenging for tar sands producers. Section 5 critiques the assumptions in the Market Analysis that tar sands transportation options will be readily available and cost-effective, such that tar sands production can profitably access markets even without KXL or any new pipeline. This section concludes that there are serious impediments to both pipeline expansion and crude by rail. Section 5.3 undertakes a rigorous review of the DSEIS assumption that crude by rail can be implemented at a sufficient scale and speed to transport all incremental tar sands production to markets, even absent new pipeline capacity. Section 5.3 demonstrates the deep flaws in this key DSEIS assumption. Section 5.4 compares pipelines and rail as transport options for tar sands. Section 6 provides an appropriate framework for analyzing tar sands expansion and breakeven costs.

In light of our evaluation of the market conditions and the assumptions of the Market analysis, Section 7 provides TGG's conclusion that KXL will have a substantial impact on tar sands expansion under a broad range of conditions and assumptions. The Section concludes with TGG's recommendations for policymakers based on our analysis.

3. DSEIS Market Analysis: Key Elements

Petroleum markets are large, complex, and highly interconnected. In turn, the DSEIS Market Analysis is lengthy and complex, with significant interrelationships between its various elements. Petroleum markets are also highly dynamic and interactive. The Market Analysis is much more static, but does (to some degree) attempt to deal with market dynamics via consideration of alternative scenarios and assumptions.

The Market Analysis is summarized in Section 1.4.1 (pp. 1.4.1 – 1.4.-2, emphasis added):

> **While the increase in U.S. production of crude oil and the reduced U.S. demand for transportation fuels will likely reduce the demand for total U.S. crude oil imports, it is unlikely to reduce demand for heavy sour crude at Gulf Coast refineries.** Additionally, as was projected in the 2011 Final EIS, the midstream industry is showing it is capable of developing alternative capacity to move Western Canadian Sedimentary Basin (WCSB) (and Bakken and Midcontinent) crudes to markets in the event the proposed Project is not built. Specifically, it is moving to develop alternative pipeline capacity that would support Western Canadian, Bakken, and Midcontinent crude oil movements to the Gulf Coast and is increasingly using rail to transport large volumes of crude oil to East, West, and Gulf Coast markets as a viable alternative to pipelines. In addition, projected crude oil prices are sufficient to support production of essentially all Western Canadian (and U.S. tight oil [footnote in original omitted]) crude oil projects, even with potentially somewhat more expensive transport options to market in the form of alternative pipelines and rail. Rail and supporting non-pipeline modes should be capable, as was projected in 2011, of providing the capacity needed to transport all incremental Western Canadian and Bakken crude oil production to markets if there were no additional pipeline projects approved.
>
> **Approval or denial of any one crude oil transport project, including the proposed Project, remains unlikely to significantly impact the rate of extraction in the oil sands, or the continued demand for heavy crude oil at refineries in the U.S.** Limitations on pipeline transport would force more crude oil to be transported via other modes of transportation, such as rail, which would probably (but not certainly) be more expensive. Longer term limitations also depend upon whether pipeline projects that are located exclusively in Canada proceed (such as the proposed Northern Gateway, the Trans Mountain expansion, and the TransCanada proposal to ship crude oil east to Ontario on a converted natural gas pipeline).
>
> If all such pipeline capacity were restricted in the medium-to-long-term, the incremental increase in cost of the non-pipeline transport options could result in a

> decrease in production from the oil sands, perhaps 90,000 to 210,000 barrels per day (bpd) (approximately 2 to 4 percent) by 2030. If the proposed Project were denied but other proposed new and expanded pipelines go forward, the incremental decrease in production could be approximately 20,000 to 30,000 bpd (from 0.4 to 0.6 percent of total WCSB production) by 2030. (As examined in section 4.15, such production decreases would be associated with a decrease in greenhouse gas emissions in the range of 0.35 to 5.3 MMTCO2e annually if all pipeline projects were denied, and in the range of 0.07 to 0.83 million metric tons carbon dioxide equivalent (MMTCO2e) annually if the proposed Project were not built.)
>
> Fundamental changes to the world crude oil market, and/or far reaching actions than are evaluated in this Supplemental EIS, would be required to significantly impact the rate of production in the oil sands.

For evaluating the Market Analysis, it is useful to first outline its most important underlying assumptions and relationships. The following key elements drive the DSEIS findings that KXL will not have substantial impacts on tar sands production (and related GHG emissions and other impacts):

1. Based to some extent on the assumptions/forecasts from US DOE EIA, and specifically the AEO (Annual Energy Outlook).

2. Generally assumes high and rising crude prices.

3. With these high crude prices, assumes that tar sands crudes will be competitive to supply existing and potential new markets (in North America and overseas).

4. Assumes significant near-term growth in North American (and specifically US) light crude production (notably from shale/tight oil), followed by a leveling out and decline of US production after 2020.

5. Assumes that competition from light crudes will not substantially impact the markets for heavy tar sands crudes and that these markets will continue to grow (including refineries undertaking new reconfiguration projects to process more heavy crudes).

6. Assumes that costs of new tar sands projects/production are moderate and increase at only the rate of general inflation.

7. Based on the above, tar sands expansion is generally assumed to be profitable and large scale expansion will proceed in all likely scenarios, even if KXL is not built.

8. Assumes that pipeline projects other than KXL are likely to be completed and will facilitate transport of tar sands crudes (especially if those other projects repurpose existing

infrastructure and right-of-ways, and/or have less complex permitting (e.g., are solely within the US or Canada and thus do not require a US Presidential Permit)).

9. To the extent that KXL and other pipelines are not completed to transport growing tar sands production to profitable markets, assumes that other logistics (notably rail) can be put in place and used to transport tar sands crudes to markets.

10. Specifically assumes that other logistics (notably rail) can be implemented at sufficient scale and speed to transport all incremental tar sands production to markets, even absent any additions of new pipeline capacity.

11. Assumes that transporting tar sands crudes by other logistics (notably rail) may have somewhat higher costs than would transport by pipelines, but the likely incremental cost is small (possibly zero in some cases, likely ranging from $2.00-$7.50/barrel, with the middle of range being $5/barrel).

12. Assumes that if transporting crudes by other logistics (notably rail) has higher costs than would pipelines, this cost penalty may impact only the tar sands production transported via other logistics, rather than impacting pricing more broadly (notably for tar sands production transported via lower cost logistics (notably pipelines)).

13. With this assumed relatively small incremental cost for transporting crudes by other logistics (notably rail), assumes that constraints on pipelines (KXL not being built, or even no new pipelines being built) will have only a small impact on tar sands logistics, costs, profitability, and development of new projects.

14. Based on the above, assumes that pipeline and other transport/takeaway capacity will not be a significant constraint on tar sands production and growth.

15. Based on all of the above assumptions and relationships, the Market Analysis concludes that that KXL will not have substantial impact on tar sands production (and thus will not have substantial impacts on GHGs and other impacts associated with tar sands production.

Finally, a significant key element that is driving the findings of the DSEIS Market Analysis is the extensive reliance on information from industry sources. The DSEIS Market Analysis is based on an assemblage of data and other information from multiple sources. While it is not uncommon for analysis of complex energy and economic issues to rely upon disparate sources, great care is needed to ensure that the overall analysis is objective, coherent, internally consistent, and will provide useful and meaningful results. The need for great care is increased when the data are (in many cases) derived from industry sources and analyses. Especially when there can be very substantial financial and other self-interest involved, data and other information should not be assumed to wholly objective; to the extent practical, inputs to the analysis should be carefully reviewed and verified for consistency and accuracy.

Given the nature of petroleum market analysis, extensive reliance on information from industry sources may be somewhat inevitable. Nonetheless, it should be recognized that in many cases, these industry sources are seeking (implicitly and often explicitly) to advocate tar sands expansion and more specifically construction of KXL and other projects relating to pipelines and other logistics. In this context, it is especially important to undertake "sanity checks" to ensure that the analysis is sound. TGG is very aware of the difficulties of energy analysis and policymaking, in general and especially at this time when the energy system is in a period of very rapid change. Decisions need to be made based on reasonably available information, and the standard is not (and cannot be) perfection. But the standard also needs to be high enough so the analysis is sound and provides a sound basis for decision-making.

Unfortunately, the DSEIS Market Analysis is substantially flawed and thus does not provide a sound basis for decision-making in regard to KXL impacts. The purpose of an EIS to identify impacts associated with a proposed Project. But in effect, the Market Analysis assumes away virtually all of the impacts associated with KXL.

As elaborated upon in the sections below, the Market Analysis assumptions and methodology are questionable. In fact, KXL could actually have a quite substantial impact on tar sands production (and thus related GHG and other impacts).

In Sections 4 to 6, TGG examines the assumptions and methodology of key elements of the Market Analysis relating to Crude Markets (Section 4), Availability and Cost of Crude Oil Transportation (Section 5) and Tar Sands Expansion and Breakeven Costs (Section 6).

4. Crude Markets

4.1. Market Analysis in a Rapidly Shifting Context

As noted in the Market Analysis (pp. 1.4-7 – 1.4-23), in recent years, the North American oil system has been undergoing dramatic shifts that are large, rapid, ongoing, and possibly accelerating. Put very simply, US crude production is rapidly increasing, but US demand for refining products is stagnant or falling, such the crude imports are rapidly falling and product exports rapidly rising. The Market Analysis claims to be up to date with respect to current information on market outlooks (p. 1.4-7):

> The analysis presented in this Supplemental EIS uses the most current information available. It examines several recent market outlooks, including the 2013 early release version of the AEO (the 2010 AEO had provided key input assumptions for the EnSys 2010 and 2011 assessments). As in 2011, the Department again consulted with experts from USDOE, and reviewed information from industry associations such as CAPP and private consulting companies such as Ensys, Hart Energy, and ICF International.
>
> The Department also relied on a January 2013 memorandum from the Administrator of the EIA that analyzed some of the key issues also presented in this section (2013 EIA Memo [footnote 7 in original omitted]). Finally, the Department also reviewed numerous comments received from the public during the National Interest Determination comment period for the previously proposed Project, and the scoping process for this Supplemental EIS.

While the AEO has begun to take into account the dramatic shifts these shifts into account, there is typically a significant lag in the AEO forecasts. So it is fair to say that the AEO (and its forecasts, specifically the AEO 2013 Early Release) is actually now a lagging indicator of emerging shifts in petroleum markets. At some point in the future, conditions may begin to stabilize, and AEO forecasts may catch up to more fully reflect emerging future realities. But for now and quite possibly for at least the next few years, each new AEO forecast will reflect major changes from the year before, but the next year’s forecast will reflect even more change.

The AEO forecasts will likely continue to be playing catch up until the boom in shale/tight oil production levels off, or at least until it becomes better understood and its future evolution becomes more predictable. And in fact, the STEO (Short-Term Energy Outlook) from US DOE EIA has already reflected some changes from the AEO 2013 Early Release, notably to substantially increase the forecast of US crude production (particularly from shale/tight oil) for 2013 and 2014.[4]

TGG is very aware of the difficulties of energy forecasting and policymaking, in general and especially in a period of very rapid change. TGG shares the view of some other energy market analysts that the recent shifts in North American oil system (notably the rapid increase in production from shale/tight oil, hydraulic fracturing (fracking), and horizontal drilling) are likely to be ongoing and possibly accelerating, as they have been for natural gas. But there are very large uncertainties associated with these shifts, and many (including many environmental organizations) continue to be skeptical that these shifts are likely to be sustained and are sustainable (in a variety of senses).

The lagging nature of the AEO forecasts (and the Market Analysis more generally) matters for evaluating KXL, since the emerging market realities are considerably less favorable for tar sands expansion. From the perspective of a few years ago (which continues to be reflected in the lagging Market Analysis), large future expansion in tar sands production might appear to be inevitable (or at least very likely). But, in reality, this large expansion is no longer so inevitable or even likely. Thus, in the current evolving context, the Presidential Permit decision on KXL has much more potential to affect tar sands development than it would otherwise. Building KXL will help to shore up the deteriorating profitability and prospects for tar sands expansion, so that more projects go ahead despite an otherwise increasingly challenging context. Not building KXL will accelerate the shifts away from tar sands expansion by discouraging near-term project development and giving more time to emerging market realities (and other factors) to constrain future tar sands expansion.

There is a wide range of opinion regarding future crude prices (for both North American and global markets). Given the shifts underway in North America and globally, some are predicting that crude prices will soften or even decline substantially from current levels.[5] In particular, the decline in waterborne imports into North America is certainly affecting crude pricing in North American markets, and there are increasing indications that this large decrease in imports will also begin to put downward pressure on global crude prices.

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[4] http://www.eia.gov/pressroom/presentations/sieminski_02212013.pdf p. 21.

[5] E.g., Verleger http://www.pkverlegerllc.com/assets/documents/TIE_W13_Verleger.pdf
and Citi, Energy 2020: Independence Day https://www.citivelocity.com/citigps/ReportSeries.action
https://ir.citi.com/dY2GZTnBVKoXNrT1sVyHcQCSQNAUUsI%2F8pXCARkTtvUOa8zDR2EckBRtxCGyJoDVW58uAgJ35%2BU%3D

4.2. US Crude Production

Based on AEO 2013, the Market Analysis assumes significant near-term growth in North American (and specifically US) light crude production (notably from shale/tight oil), but US production will then level out and decline after 2020. Following the AEO 2013 Early Release in December 2012, the February 2013 Short Term Energy Outlook (STEO) substantially increased the forecast of US crude production (notably from shale/tight oil) for 2013 and 2014.[6]

There is wide uncertainty and controversy regarding growth in US crude production. But at least in the short-term, the reality is that production is growing very fast and that this growth is (if anything) accelerating, rather than moderating. For a variety of reasons, this growth may not be sustained (or sustainable), but it is relevant to consider that there are notable parallels between the recent evolution of oil and gas production and markets. Many were skeptical that shale gas production had large potential, would continue to grow, and would result in substantially lower natural gas prices over an extended period. And some still are skeptical. But at this point, it is becoming increasingly clear that shale gas is in many ways a game changer for North American (and possibly global) gas markets. There are some notable differences between gas and crude markets, and the evolution of shale/tight oil is at an earlier stage of development than is shale gas. Nonetheless, it is becoming increasingly credible that shale/tight oil will also be in many ways a game changer for North American (and possibly global) crude markets.

4.3. Competition between Crudes

The Market Analysis assumes that competition from light crudes will not substantially impact the markets for heavy tar sands crudes and that these markets will continue to grow (including refineries undertaking new reconfiguration projects to process more heavy crudes). In particular, the Market Analysis assumes that refineries now configured to process heavy crudes (notably on the Texas Gulf Coast) are unlikely to shift away from heavy crudes to process more light crudes (pp. 1.4-20 - 1.4-22, emphasis added):

> The AEO outlooks, as well as the current trends in the market, suggest that increased production of tight oil (light, sweet grade of crude oil), has not impacted the demand for heavy, sour crude oil at the U.S. refineries optimized to process heavy crude oil. The EIA notes, "AEO2013, AEO2012, and AEO2011 all project continued strong demand for heavy sour crudes from Gulf Coast refiners that are optimized to process such oil" (see the 2013 EIA memo in Appendix C, Market Analysis Supplemental Information). A main driver for this is that **although**

[6] http://www.eia.gov/pressroom/presentations/sieminski_02212013.pdf p. 21.

> **refiners' can be expected to make adjustments in their operations to take advantage of the increased supply of light crudes on the markets, shutting down their heavy crude upgrading units would likely be the most inefficient and expensive option.**

The Market Analysis assumes that Canadian tar sands will provide an increasing share of US heavy crude supply, and perhaps almost completely displace other suppliers by 2035 (pp. 1.4-20 - 1.4-23), Finally, based on the AEO 2013 forecast, the Market Analysis assumes that US light crude production from shale/tight oil will result in a bulge over the next few years, but then plateau and begin to decline after 2020. The Market Analysis (pp. 1.4-20 - 1.4-26) thus makes the further assumption that US refineries will undertake new reconfiguration projects to shift to using more heavy tar sands crudes, even if they also undertake smaller projects to facilitate processing light shale crudes. According to p. 1.4-26:

> The difference in long-term growth projections between the light sweet tight oil versus the WCSB heavy crudes could be expected to impact refiners' decisions regarding their investments. Refiners take long-term growth projections of different types of oils into account when they decide whether to make whatever improvements are necessary to process one grade of crude versus the other. The 2013 AEO early release version projects a relatively rapid increase in U.S. total crude oil production, spurred by shale developments, followed by a peak and decline, such that by the late 2020's the outlook is little changed from that in the 2010 AEO. Thus, this latest EIA projection indicates a relatively short- to medium-term "bulge" in U.S. crude production followed by a return to a downward trend. In contrast, projections from CAPP and others of WCSB production are for a steady, sustained growth over the medium- to long-term, in large part because the bulk of the growth is projected to come from oil sands which do not suffer the same decline profiles as do conventional and especially "tight" crudes.
>
> Since major refinery projects are evaluated based on a presumed 15+/- year life, this distinction between projected supply growth in the United States ("bulge" of light crudes) and in Western Canada (steady growth of heavy crudes) may provide a basis for two types of capital investments: major, long-term expenditure to process heavy WCSB crude supplies, and smaller "revamp" projects with shorter payback periods to process light "tight" crude oils.

Refinery configurations and choice of crude slate are complex and highly technical issues. But, at a minimum, the likely reality is much more nuanced than the Market Analysis findings that the US refineries that can process heavy crudes will do so, and that the US market for heavy tar sands crude will continue to grow as refineries reconfigure to process more heavy crude and tar sands displaces other sources of heavy crudes. As somewhat acknowledged deep within the

Market Analysis, refinery decisions on crude sourcing and configuration are economically driven and will shift in response to changing market conditions (Appendix C, p. 3):

> refiners will shift their crude slate if they determine that they could achieve a higher profit level by making changes to their crude runs or crude slate, including making investments to shift to a lighter crude slate. Refiners determine the optimal crudes to process like any other manufacturing company selecting the right raw materials to manufacture products. Refining companies (including refining divisions in large, integrated major oil companies) pay market prices for the crude oil they run and measure their profitability based on selling their product into the wholesale spot market with an added margin. They then use that margin to cover their fixed and variable expenses. Refiners may select a more expensive crude oil if that crude oil's yield provides a greater margin than a cheaper crude.

In fact, the US market for heavy crude and specifically tar sands heavy crude, may be significantly smaller and less profitable than assumed by the Market Analysis. Competition from light crudes will impact demand and pricing for heavy crudes. This competition will impact both operating decisions and capital (investment).

4.4. Operating Decisions to Shift Crude Slate

Decisions to operate cokers and process heavy crudes are economically driven. Cokers are energy intensive and have sizable operating costs. Cokers will only be operated if heavy crude prices are substantially below light crude prices; at smaller price differentials, refiners will shift to lighter crudes. According to CIBC 2012[7] (p. 104):

> **There will be significant competition from not only WCS vs. Maya for access to the PADD 3 market, but also for light oil trying to get access to higher complexity refineries. A complex refiner will take light oil…if the price is right.**
>
> **The Fight For Refinery Access In PADD 3, Lots Of Coking Capacity But Refiners Have Flexibility:** PADD 3 is the largest Coking market in the world with approximately 3.2 MMBbls/d of heavy oil capacity. With this much installed capacity, it seems quite a natural fit for lower-quality Canadian crudes such as WCS or for continued intake of Maya. However, just because PADD 3 is home to

[7] Canadian Imperial Bank of Commerce (CIBC). 2012. Too Much of A Good Thing: A Deep Dive Into The North American Energy Renaissance. Institutional Equity Research Industry Update. August 15, 2012; referred to in DSEIS Market Analysis and in this report as CIBC 2012. Website: http://www.scribd.com/doc/109921666/CIBC-NA-Energy-Economy-Too-much-of-a-good-Thing-Full-report. (Accessed April 14, 2013.)

significant coking capacity, doesn't mean it will all be used. Any refinery that has coking capacity can take a higher-quality crude oil slate (the opposite clearly doesn't hold true though). There are many tradeoffs involved in the equation but it basically boils down to margin. A high complexity coking refinery may opt to run at slightly lower rates by taking a higher slate of light oils. The decision will be governed almost entirely by their margin analysis, which would incorporate the higher yield typically obtained from a lighter barrel together with factors such as lower wear and tear on the refinery and fewer catalyst costs, etc. In our discussions with refiners, we have typically heard that heavier barrels like Maya could not sustain a differential vs. light barrels of anything beyond US$5-US$9/Bbl. Indeed this seems to correlate with historical Maya vs. LLS differentials, which have averaged in the US$10/Bbl range. The overall point from this discussion is that there will be significant competition from not only WCS vs. Maya for access to the PADD 3 market, but also for light oil trying to get access to higher complexity refineries. As discussed previously, this multifaceted competition shifts the balance of power to the refiners – which they will use to their advantage (as we have seen already in PADD 2).

The issue of competition between light and heavy crudes and possible idling of cokers has also been addressed in other recent analysis: [8]

> As light-heavy spreads compress, the incentives for light-heavy switching increase – $4-7 levels have been a "floor" level in the past – further pressure could see idling of cokers and some push-out of medium and heavy crude imports, weakening Mars/Maya even as LLS falls, to keep the spread from narrowing too far for extended periods.

In practice, heavy crudes may not be displaced, but they will have to be sufficiently discounted so that they will not be displaced. Thus, competition from light crudes puts downward pressure on pricing (and possibly demand) for heavy crudes. And as discussed Section 4.6, competition between heavy crudes (tar sands vs. waterborne imports) also puts downward pressure on pricing (and perhaps demand for tar sands crudes). At a low enough price, there is likely to be a market for tar sands heavy crudes, but this price discounting will make tar sands production and expansion less profitable. And in turn, this will tend to constrain expansion relative to what is likely in a higher price scenario. More generally, consideration of these complex dynamics illustrates that there is more interaction and competition between markets than assumed by the Market Analysis

[8] Citi, Energy 2020: Independence Day, p. 41 Website: https://ir.citi.com/dY2GZTnBVKoXNrT1sVyHcQCSQNAUUsI%2F8pXCARkTtvUOa8zDR2EckBRtxCGyJoDVW58uAgJ35%2BU%3D

These downward pressures on crude pricing can be amplified when product is oversupplied into a constrained market, giving refiners ability to secure large discounts from the multiple suppliers competing for a limited market. According to CIBC 2012 (pp. 103-104):

> **The "Refinery X-Factor" & Balance Of Power**: […] quantifying price discounts is a complex matter. The logic is relatively straight forward when it is simply transportation and quality related. However, the third component is the most difficult to define, and that is what we term the "refinery X factor". What we mean by this is that when a situation arises in which a product is oversupplied into a constrained market, the consumer (refineries in this case) have the balance of power. With hundreds of market participants all fighting for limited refinery capacity, discounting emerges and it is largely at the hands of the refiner as to where the magnitude of those discounts.

The Gulf Coast refiners with heavy crude processing listed in Market Analysis Table 1.4-5 include Flint Hills Resource LP. As shown in Table 1.4-5, Flint Hills processed only a small amount of heavy crude imports during the January-June 2012 period, equivalent to just 4% of refinery capacity. Meanwhile, other refiners in Table 1.4-5 processed much larger amounts of heavy crudes. For the other refiners, heavy crude imports averaged about 41% of refinery capacity. [9] But heavy crude imports were more than half of refinery capacity at some refiners, notably Houston Refining, Deer Park Refining, ConocoPhillips, and Total.

Various factors will influence refinery decisions on crude slate, but one key factor is coking capacity. Within the subset of refineries that are equipped with coking capacity, some refineries have large amounts of coking capacity (relative to overall refinery capacity and throughput), and thus can process a crude slate weighted towards heavy crudes. Other refineries have smaller amounts of coking capacity, and thus are limited in the amount of heavy crudes they can process. Refineries with limited amounts of coking capacity may process some heavy crudes, as well as a substantial amounts of lighter (light and medium) crudes.

Given the small amount of heavy crude imports at Flint Hills, it might be assumed that this refiner has only a minimal amount of coking capacity. But in fact, the Flint Hills refinery in Corpus Christi, Texas has 14,400 bpd of coking capacity, and thus might be able to process substantially more heavy crudes than the amount indicated in Table 1.4-5.[10] Within the constraints of the DSEIS process, TGG has not been able to fully research this issue, but it

[9] As discussed in Note [c] to Table 1.4-5, the Motiva Port Arthur refinery was offline for most of the January-June 2012 period. Thus, we have excluded it when calculating heavy crude imports as a share of refinery capacity. For all refiners in Table 1.4-5, except for Flint Hills and Motiva, refinery capacity totals 3,916,413 bpd, and heavy crude imports total 1,598,093 bpd. Thus,

[10] US EIA Refinery Capacity Report June 2012 With Data as of January 1, 2012, p.20.
Cokers process the heavy end of the barrel, the residuum from the refinery distillation processes. In effect, cokers process the heaviest portion of heavy crudes. Thus, for a given amount of coking capacity, a refinery can process a substantially larger amount of heavy crude throughput.

would appear that Flint Hills is choosing to process a lighter crude slate and not fully utilize its coking capacity. If so, Flint Hills may provide some indication of how some refiners may respond to the dramatic ongoing shifts in North American crude production. The Flint Hills Corpus Christi refinery is very proximate to the large and rapidly growing light crude production from the Eagle Ford shale.

In fact, as discussed in Section 4.5, Flint Hills is also planning to undertake capital investments to shift crude slate in response to rapidly increasing light crude production.

4.5. Capital Investment to Shift Crude Slate

As discussed in Sections 4.3 and 4.4, the Market Analysis assumes that competition from light crudes will not substantially impact the markets for heavy tar sands crudes and that refineries now configured to process heavy crudes (notably on the Texas Gulf Coast) are unlikely to shift away from heavy crudes to process more light crudes. In particular, the Market Analysis assumes that refinery capital investments would include major projects to process more heavy tar sands crudes, as well as more minor revamp projects to process light crudes from shale/tight oil (p. 1.4-26):

> Since major refinery projects are evaluated based on a presumed 15+/- year life, this distinction between projected supply growth in the United States ("bulge" of light crudes) and in Western Canada (steady growth of heavy crudes) may provide a basis for two types of capital investments: major, long-term expenditure to process heavy WCSB crude supplies, and smaller "revamp" projects with shorter payback periods to process light "tight" crude oils.

In support of this assessment, the Market Analysis explains why it might not be cost-effective for refineries now configured to process heavy crudes to undertake modifications to process more light crudes (Appendix C, p. 3):

> A refiner that processes heavy crudes has invested significant amounts of money to install the equipment necessary to process them. A refiner that has made these investments has economic incentive to continue to process heavy crudes and may not be able to process significantly lighter crude slates as profitably. For example, if a refinery configured to process a heavy slate of crude oil was constrained to processing only a light crude oil slate, the volume of gasoline and diesel fuels produced could decrease by 15 to 20 percent. This, in most cases would be because the refiner's crude oil distillation process is designed for crudes with much less light components, such as naphtha, as heavier crudes. Attempting to process high percentages of light crude oil in these units would overload the distillation towers with light products and require a reduction in crude processing. Not only would the refiner usually be paying relatively more for that light slate of crude oil, it would be producing less gasoline and diesel from it.

> This is the primary reason refiners would not typically replace a heavy crude oil slate with 100 percent light crudes (IHS CERA 2011).
>
> To go back to efficiently process more light crudes more economically, those refiners would have to make additional expenditures in refinery equipment to reconfigure the distillation towers to handle the lighter crude, and add capacity to process the higher naphtha content into finished gasoline. Thus, even if an influx of light domestic crudes makes them comparatively price advantaged to heavy crude oils, the size of capital expenditure and downed production time for refiners may offset potential benefits of trying to process more light crudes (Platts 2012).

TGG agrees that it is relevant to consider the issues described in the above quotation from the Market Analysis. That said, it is also important to point out that shifting from heavy to light crudes is a much less complex, expensive, and time consuming process, compared with shifting than from light to heavy crudes. Reconfiguration projects to shift from light to heavy crudes typically cost billions and take many years. Modifications to shift from heavy to light crudes typically cost hundreds of millions and take a few years.

The reconfiguration projects that have been undertaken by some refineries may resulted in stranded investment. Refineries that have invested in cokers and other capability to process heavy crudes would typically prefer that these investments be utilized and profitable. But especially over time, refineries will shift to process lighter crudes if that is more profitable on a forward-looking basis. Moreover, shifts to process light crudes can also have the advantage of reducing operating costs; cokers and other refinery units that process heavy crudes are energy-intensive and have sizable operating costs.

Within the constraints of the DSEIS process, TGG has not been able to fully research this issue, but it would appear that Flint Hills is choosing to undertake a major investment and reconfiguration to process a lighter crude slate at its Corpus Christi refinery. [11] As discussed in Section 4.4, Market Analysis Table 1.4-5 includes Flint Hills in its listing of Gulf Coast Area refiners processing heavy crudes. Flint Hills is now seeking regulatory approval to undertake a major upgrading of this refinery to increase the amount of Eagle Ford crude that it can process:[12]

> Flint Hills Resources, a subsidiary of Koch Industries, has proposed upgrading its Corpus Christi West Refinery to increase the amount of Eagle Ford crude it would be able to process. The $250 million dollar project would

[11] This refinery is a combination of two connected plants, the West Refinery (230,000 bpd) and the East Refinery (70,000 bpd). The 14,400 bpd coker is part of the West Refinery.

[12] Tunstall, Thomas, et al. Economic Impact of the Eagle Ford Shale, University of Texas San Antonio Institute for Economic Development. March 2013, p. 65 (emphasis added). Website: http://bit.ly/11anGAU. Accessed April 21, 2013.

> not necessarily add capacity, but rather enhance current operations to optimize light sweet input by installing new equipment, modifying current configurations and upgrading control technology.[81] **New processing towers, heaters, piping, tanks, pumps and valves would be installed in the place of older equipment built to refine heavy sour imports** over the course of two years pending approval from the Texas Commission for Environmental Quality and the Environmental Protection Agency. As of October 2012, the 300,000 barrel per day refinery was processing up to 150,000 barrels per day of Eagle Ford Crude.

The citation above indicates that the new equipment to process lighter crudes will replace older equipment built to process heavy sour crudes.[13]

Aside from the issue of whether refiners will shift from heavy to light crudes, there is also the issue of whether refiners will shift from light to heavy crudes. As discussed in Section 4.3, the Market Analysis assumes that North American refineries will undertake new reconfiguration projects, to add coking capacity and shift crude slate from light to heavy. But as noted above, reconfiguration projects to shift from light to heavy crudes typically cost billions and take many years. Refiners will only undertake these projects if they expect them to provide an adequate return over an extended period.[14]

In contrast to short-term operating decisions, long-term investment decisions to add cokers are dependent upon long-term expectations regarding crude pricing and supply. Specifically, reconfiguration projects to shift from light to heavy crudes are evaluated based on expectations regarding future price differentials between light and heavy crudes.

A few years ago, it appeared likely that future light crude supply would be limited and expensive, and that tar sands expansion would be the only major source of growth in North American crude production. In this context, many US refiners undertook reconfiguration projects to shift from light to heavy crudes and specifically to enable processing of heavy tar sands crudes.

Crude markets have shifted dramatically over the last few years and these shifts are continuing and possibly accelerating. In particular, the growth in North American light crude production has been very large and rapid. Moreover, this growth has routinely exceeded expectations, such that both output and forecasts/expectation of output are rising very quickly. In this context, North

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[13] Extensive information regarding the Flint Hills Corpus Christi West Refinery and the project to utilize more Eagle Ford crude is provide on the Project Eagle Ford website http://www.fhrcorpuschristi.com/, including:
Permit application to TCEQ (Texas Commission on Environmental Quality)
http://www.fhrcorpuschristi.com/upload/FHRProjEagleFordAmendment%20ApplicationRecdbyTCEQDraft.pdf and
Permit application to US EPA
http://www.fhrcorpuschristi.com/upload/FHRProjEagleFordWestGreenhouseGasApplicationDraft.pdf
which in turn includes refinery PFD (Process Flow Diagram), Process Description, and Emissions Data.

[14] As noted in the Market Analysis (p. 1.4-26), "major refinery projects are evaluated based on a presumed 15+/- year life".

American refineries are unlikely to undertake new reconfiguration projects (to shift crude slate from light to heavy), especially until and unless the boom in North American light crude production levels out and possibly reverses.[15] As noted in the Market Analysis (Appendix C, p. 4, emphasis added):

> Valero has elected to cancel a major project at its Texas City refinery to construct a coker [footnote 3 in original omitted] (referred to in the 2011 Final EIS market analysis). **Valero commented that due to the increased supply of domestic light crude oil and delivery uncertainty of heavy crude oil supplies from the WCSB (because of potential ongoing constraints on additional pipeline capacity, particularly uncertainty about the proposed Project), light/heavy crude price differentials would narrow and would make additional new investments to process heavy crude uneconomic** (Reuters 2012).

Based on the AEO 2013 forecast, the Market Analysis assumes that US light crude production from shale/tight oil will result in a bulge over the next few years, but then plateau and begin to decline after 2020. If that scenario actually occurs, it is possible that North American refiners might then begin to consider new reconfiguration projects to shift from light to heavy crudes. Many factors will influence future refinery decisions, including tar sands development and logistics to transport tar sands crudes. As commented by Valero in its recent decision to cancel a major coker project, ongoing constraints on additional pipeline capacity will likely play a role in determining whether refineries undertake reconfiguration that would expand markets for heavy tar sands crudes.

4.6. Refinery Ownership by Non-Canadian Heavy Crude Producers

Some Gulf Coast heavy crude refineries are less likely to process tar sands crudes because these refineries have ownership by non-Canadian heavy crude producers. The Gulf Coast refineries with heavy crude processing listed in Market Analysis Table 1.4-5 include Citgo Lake Charles and Corpus Christi (Venezuela PDVSA), Deer Park (Mexico PEMEX), and Motiva Port Arthur (Saudi Aramco). As noted elsewhere in the Market Analysis (Appendix C, p. 5, but not in relation to Table 1.4-5):

> Since Motiva is a joint venture between Shell and Saudi Aramco, there may be some equity obligations that may limit the option or the volume of WCSB crude oil that could be processed.

[15] Some reconfiguration projects are now underway (notably as at BP Whiting) to enable processing more heavy tar sands crudes) and will be completed and ramped up to full production over the next few years.

These foreign government-owned heavy crude producers bought equity shares in US refineries, and often invested large amounts to install cokers and expand the refineries, in order to assure a market for their own heavy crude production.[16] As noted elsewhere in the Market Analysis (Appendix C, p. 3, but not in relation to Table 1.4-5):

> PADD 3 has a particularly high heavy crude oil processing capacity in part because of the proximity of large supplies of heavy crude oil in Mexico and Venezuela. In addition, Mexico and Venezuela, through their state-controlled oil companies, supported expansion of the heavy oil refining capacity through several joint-venture investments in Gulf Coast refineries to create a more profitable market for their heavy crude oil resources.

As a result of this ownership by non-Canadian state-controlled heavy crude producers, these refineries are less likely to shift to processing tar sands crudes.

Moreover, crude pricing for these refineries is to some extent a matter of internal accounting, rather than market pricing. These refineries are selling products into high priced domestic and export markets, so their main rationale may be to process heavy crudes into products, rather than maximize revenues from selling the crudes themselves. Thus in practice, these foreign heavy crude producers may price their crudes to assure they are processed at these refineries. If tar sands crudes are cheaper and might otherwise displace these other heavy crudes from their market at these refineries, the heavy crude producers that own equity shares in these refineries can simply drop their crude pricing.[17] And such a strategy can still be profitable for the crude producers, since it will increase the refinery margins and the crude producers share of the profits from refining.

4.7. Conclusions

Section 4 evaluates the DSEIS analysis in a rapidly shifting context. TGG compares the DSEIS analysis with information from a number of sources and determines that the DSEIS analysis is not properly reflective of emerging market conditions. As part of our analysis in this Section, TGG examined (i) US crude production; (ii) competition between different crudes; (iii) capital

[16] http://www.nytimes.com/2013/04/05/business/texas-refinery-is-saudi-foothold-in-us-market.html?pagewanted=2&_r=0&pagewanted=all;
http://www.beg.utexas.edu/energyecon/new-era/case_studies/Deer_Park_Refinery.pdf;
Verleger, Philip. The Tar Sands Road to China (discussed in KXL FEIS Appendix V DOE Response to Verleger Report), pp. 10-12; Verleger, Philip. Keystone as Trojan Horse, pp. 19, 21-22.
http://www.pkverlegerllc.com/assets/documents/Keystone_as_Trojan_Horse1.pdf

[17] http://www.rbnenergy.com/sailing-stormy-waters-canadian-heavy-crude-after-the-pipelines;
Verleger, Philip. The Tar Sands Road to China (discussed in KXL FEIS Appendix V), pp. 10-14;
Verleger, Philip. Keystone as Trojan Horse, pp. 8, 19-22
http://www.pkverlegerllc.com/assets/documents/Keystone_as_Trojan_Horse1.pdf.

investment and operating decisions that shift the crude slate; and (iv) foreign refinery ownership issues affecting Canadian tar sands. In light of this crude markets analysis, TGG concludes that emerging and dynamic conditions in the crude markets may become increasingly challenging for tar sands producers. Under challenging economic conditions, it is even more essential for tar sands producers to have access to high volume, low cost logistics. Therefore the approval of KXL will have a significant impact as an enabler of less profitable marginal tar sands projects that could not be constructed without access to low cost logistics.

5. Availability and Cost of Crude Oil Transportation

5.1. Introduction

The Market Analysis asserts that crude oil transportation will be readily available and cost-effective, such that tar sands production can profitably access markets, even without the proposed Project, or any new pipelines. According to p. 1.4.1 (emphasis added):

> **[T]he midstream industry is showing it is capable of developing alternative capacity to move Western Canadian Sedimentary Basin (WCSB) (and Bakken and Midcontinent) crudes to markets in the event the proposed Project is not built.** Specifically, it is moving to develop alternative pipeline capacity that would support Western Canadian, Bakken, and Midcontinent crude oil movements to the Gulf Coast and is increasingly using rail to transport large volumes of crude oil to East, West, and Gulf Coast markets as a viable alternative to pipelines. […] **Rail and supporting non-pipeline modes should be capable, as was projected in 2011, of providing the capacity needed to transport all incremental Western Canadian and Bakken crude oil production to markets if there were no additional pipeline projects approved.**
>
> Approval or denial of any one crude oil transport project, including the proposed Project, remains unlikely to significantly impact the rate of extraction in the oil sands, or the continued demand for heavy crude oil at refineries in the U.S. **Limitations on pipeline transport would force more crude oil to be transported via other modes of transportation, such as rail, which would probably (but not certainly) be more expensive.** Longer term limitations also depend upon whether pipeline projects that are located exclusively in Canada proceed (such as the proposed Northern Gateway, the Trans Mountain expansion, and the TransCanada proposal to ship crude oil east to Ontario on a converted natural gas pipeline).

Assumptions regarding availability and cost of crude oil transportation are of central importance for the Market Analysis. As previously summarized in Section 3, the Market Analysis is premised upon following assumptions regarding availability and cost of crude oil transportation:

- Assumes that pipeline projects other than KXL are likely to be completed and will facilitate transport of tar sands crudes (especially if those other projects repurpose existing infrastructure and right-of-ways, and/or has less complex permitting (e.g., are solely within the US or Canada and thus do not require a US Presidential Permit)).

- To the extent that KXL and other pipelines are not completed to transport growing tar sands production to profitable markets, assumes that other logistics (notably rail) can be put in place and used to move tar sands crudes to markets.

- Specifically assumes that other logistics (notably rail) can be implemented at sufficient scale and speed to transport all incremental tar sands production to markets, even absent any additions of new pipeline capacity.

- Based on the above, assumes that pipeline and other transport/takeaway capacity will not be a significant constraint on tar sands production and growth.

Section 5 critiques these assumptions in the Market Analysis that drive the erroneous assumption that pipeline and other transport/takeaway capacity will not be a significant constraint on tar sands. In this Section, TGG conducts a review of the serious impediments to both pipeline expansion and crude by rail. Section 5.2 evaluates the Market Analysis regarding increases in pipeline capacity other than the proposed Project. Section 5.3 evaluates increases in rail capacity. In particular, Section 5.3 undertakes a detailed review of the DSEIS assumption that crude by rail can be implemented at a sufficient scale and speed to transport all incremental tar sands production to markets, even absent new pipeline capacity. Section 5.3 demonstrates the deep flaws in this key DSEIS assumption. Section 5.4 concludes that crude by rail is not well matched for the transport of tar sands crude in terms of both cost effectiveness and risk factors.

5.2. Increases in Pipeline Capacity

5.2.1. Introduction

KXL is not unique in terms of encountering major opposition, delays, and uncertainty of completion. Similar difficulties are also being encountered by other major pipeline projects that would transport tar sands production. Pipeline projects to transport crude west through British Columbia (Northern Gateway and Trans Mountain Expansion) are now seen as unlikely to be completed. A smaller project to reverse and expand an existing crude pipeline east from Ontario (Enbridge Line 9, and possibly the Portland-Montreal Pipeline) is likewise the subject of significant public concern and opposition. Another major project to transport crude east across Canada (TransCanada Energy East) is still in early stages of development, but will also encounter intense opposition if it moves forward.

5.2.2. Pipelines to the West: Northern Gateway and Trans Mountain Expansion

The Market Analysis has acknowledged the controversial nature of pipeline projects in British Columbia (BC) and the significant public opposition and uncertainty associated with each of them:[18]

> There are several pipelines proposed for transporting WCSB crude oil to the Pacific, including Trans Mountain to Vancouver and Northern Gateway and Northern Leg to Kitimat. These pipelines have been controversial and are encountering significant opposition. It is uncertain whether such projects ultimately will be approved. (p. 2.2-19)
>
> […]
>
> Enbridge is proposing to construct the Northern Gateway pipeline, which would transport up to 525,000 bpd of crude oil 1,177 km from Bruderheim, Alberta, to the Port of Kitimat, British Columbia. The port would be improved with two dedicated ship berths and 14 storage tanks for crude oil and condensate. Enbridge intends for the pipeline to be operational around 2017. A regulatory application was submitted in 2010, which is undergoing an independent review process led by the Canadian National Energy Board and the Canadian Environmental Assessment Agency. The pipeline would traverse First Nation traditional lands and important salmon habitat. The project has been controversial and has encountered opposition from some First Nation bands and other organizations. Opposition to the project remains strong as evidenced by media reports of the January 2013 public hearings in Vancouver on the permit application. It remains uncertain at this time if the project would receive permits and be constructed, and therefore the option of moving additional crude to Kitimat was eliminated from detailed analysis. (p. 2.2-27)

Enbridge's Northern Gateway Pipeline and Kinder Morgan's Trans Mountain Expansion would greatly increase tanker traffic on the BC coast, and are unlikely to be approved. Since 2011, Northern Gateway has been the object of intense and ongoing public opposition on the part of large First Nations and environmental coalitions, as well as thousands of diverse intervenors from a broad cross-section of BC society, who have participated (and dramatically slowed down) a Canadian federal hearing process to evaluate the project. If this project is cancelled, opposition will shift its focus to the other proposed pipeline in BC, Kinder Morgan's Trans Mountain expansion.

As noted in CIBC 2012 (p. 8), the major BC pipeline projects (Northern Gateway and Trans Mountain Expansion) are unlikely to proceed:

> There are currently ~2.9 MMBbls/d of longhaul pipeline proposals on the table (out of Western Canada). That sounds like a lot until one considers that two of the largest (the

[18] DSEIS, pp. 1.4-26 -1.4-28; 1.4-64; 2.2-19, 2.2-27.

> proposed 525,000 Bbls/d Gateway and 450,000 Bbls/d TMX expansion through B.C.) face ever-increasing political risk and we assign no better than 50/50 odds that these pipes are built before the end of the decade.

Dr. Jaccard agrees that the BC pipeline projects are unlikely to proceed and explains in detail why they have a low probability of completion: [19]

> Both of these would involve a dramatic increase in oil tanker traffic on the BC coast, in the latter case through the port of Vancouver.
>
> The Northern Gateway pipeline proposal is opposed by aboriginal bands along its route and on the coast, and their land rights in BC have a strong standing in the courts (most have not signed treaties that extinguished their land claims). Just as important, BC will have a provincial election in May. The main political opposition has a significant lead in opinion polls (almost 20 points for the past several months) and has promised to do everything it can to stop Northern Gateway should it be elected, and should the project be approved by the Canadian federal government. As a new government, it could launch its own environmental assessment, and afterwards impose stringent conditions that would effectively render the project infeasible.
>
> The Trans Mountain pipeline expansion proposal is opposed by key municipal governments in the Vancouver metropolitan region, including the city of Vancouver. These municipal political leaders reflect the strong concerns of a significant percentage of their voters about the risks of pipeline ruptures and oil tanker accidents. Since governments at the provincial and federal level are dependent on voter support in the region, political enthusiasm for the project is unlikely. Again, aboriginal bands along the route and on the coast oppose the project and vow to fight it in the courts. Thus far, most opposition to bitumen transport through BC has focused on the Northern Gateway. If the project is cancelled, this opposition would shift its focus to the Trans Mountain expansion proposal.
>
> Industry analysts have noted that these pipelines through BC have less than a 50% chance of being built. If they and Keystone are not built, industry watchers agree that oil sands output will be reduced from what it otherwise would have been.

[19] http://docs.house.gov/meetings/IF/IF03/20130410/100616/HHRG-113-IF03-Wstate-JaccardM-20130410.pdf pp. 2-3. Dr. Jaccard is (among other things) an energy and environmental expert based in Vancouver, as well as former head of the British Columbia Utilities Commission. Thus, he has substantial experience and expertise regarding energy development in BC, and specifically whether projects are subject to intense opposition, and thus have a low probability of being completed.

Pipeline opponents in North America are a broad, diverse and dynamic transnational social movement, made up not only of environmental groups, but of a broad cross-section of civil society including indigenous groups, labor, students, citizens, scientists, artists, land-owners, and communities and regions directly affected by the pipelines,. Pipeline opposition is dynamic and can quickly shift from project to project (e.g., as Dr. Jaccard points out, if approval for Northern Gateway is denied, activists will turn their attention to Trans Mountain). Pipeline activists can also shift their opposition to pipeline alternatives such as crude by rail, as will be discussed in Section 5.3.

5.2.3. Pipelines to the East: Line 9 and Energy East

Enbridge Line 9 and TransCanada Energy East are major pipeline projects that involve repurposing of existing infrastructure to enable transport of tar sands (and other) crudes eastward into Ontario and Quebec; the Market Analysis claims that development of these projects supports the view that pipeline capacity will be added to enable transport of tar sands (and other) crudes:

> Enbridge has an array of projects under the heading “Eastern Access” to increase capacity to take WCSB, and also potentially Bakken, crudes to refineries in eastern PADD 2 but primarily in Sarnia, Ontario, and potentially Quebec and Montreal. In association with these projects, which include the re-reversal of Line 9 so it again runs east from Sarnia to Montreal, is the possible reversal of the Portland, Maine, to Montreal pipeline to also run east.
>
> […]
>
> The Final EIS and EnSys 2011 had noted that projects for interstate petroleum pipelines that do not cross an international border face less regulatory review, especially when they entail modifications to existing lines or rights of way, which was one of the reasons a complete No Expansion shut-in of new capacity was considered unlikely. The development of these projects supports that assessment, and supports the view that, in general, absent larger regulatory changes one can expect infrastructure developments to follow market patterns of supply and demand, which EnSys had described as “business as usual”. These firm projects add up to a major and on-going re-working of the U.S./Canadian crude oil pipeline logistics system as the industry adapts to changing market conditions precipitated by the growth in WCSB and Bakken and Midcontinent production. In addition, other possible projects are constantly being considered.
>
> The following are two important current examples that have been discussed as possibilities (no action has been taken on either):

> A possible TransCanada project to convert one or more existing natural gas pipelines that run from Alberta to Ontario and on to Quebec to crude oil service. Potential capacity has been reported as up to 600,000 bpd with capability to carry both light and heavy/oil sands WCSB streams.

In fact, in addition to pipeline controversy in Western Canada, public opposition (among environmental and First Nations groups, as well as landowners and citizens) is growing in Ontario and Quebec around the Line 9 and Energy East projects.

Enbridge has now applied to the National Energy Board (NEB) for approval to reverse and expand Line 9 capacity, to transport 300,000 bpd of heavy and lighter crudes eastward to Montreal.[20] Line 9 extends through the largest metropolitan areas in Canada (Toronto and Montreal), and is highly proximate to both human activity and water.

TransCanada's Energy East Project would transport crude (notably from tar sands production) to refineries and marine loading terminals in Quebec and New Brunswick (Saint John); this 2700 mile project would repurpose a portion of TransCanada's gas Mainline, with new pipe constructed in Alberta, Saskatchewan, Eastern Ontario, Québec and New Brunswick to link up with the pipe converted from gas service.[21] Energy East is still in early stages of development, with an open season now under way.[22] Capacity could be between 500,000 and 850,000 bpd, depending upon commercial interest. It is uncertain what the finalized design will be for this project, whether it will move forward and how fast.

As noted by both CIBC 2012 and Dr. Jaccard, respectively, in the following citations, Energy East will also be the subject of intense opposition, especially in Quebec.

> The proposed TransCanada Mainline conversion (estimated ~600,000 Bbls/d) is compelling but very early stage and could also provoke some political backlash in Quebec. [23]

> TransCanada is exploring the option of transforming its west-to-east mainline from natural gas to bitumen. This proposal would require the conversion of a half century old natural gas pipeline right-of-way to move oil sands bitumen – a plan that will generate more public scrutiny following the rupture of the repurposed Pegasus pipeline in Arkansas. Moreover, TransCanada's plan would require the construction of a pipeline along new right-of-ways through Quebec and New Brunswick. This would not equate to all of the oil sands development that would have been enabled by Keystone XL and either of the BC pipelines, and it would again trigger a reaction as provincial governments along the way were presented with public concerns similar to those in BC.

[20] http://www.neb.gc.ca/clf-nsi/rthnb/pplctnsbfrthnb/nbrdgln9brvrsl/nbrdgln9brvrsl-eng.html
http://www.enbridge.com/ECRAI/Line9BReversalProject.aspx
[21] http://transcanada.com/6246.html
[22] http://transcanada.com/6286.html
[23] CIBC 2012, p. 8.

> It must be remembered that opinion polls show that at least 40% of Canadians oppose oil sands expansion. Opposition toward oil sands infrastructure in Quebec, where new pipeline right of ways and construction would be required, is particularly strong.[24]

Particularly in Quebec, activists are already mobilizing against the Line 9 and Energy East projects. Quebec has a long history of strong citizen activism and a vibrant protest culture, as evidenced by widespread student protests and strikes of 2012. In particular, Quebec has a high level of concern (and resistance) regarding fossil fuel development, as evidenced by major citizen opposition to shale gas in Quebec, which led to a recent province-wide ban on hydraulic fracturing (fracking). Indeed, the theme of this year's Earth Day March in Montreal (on April 21, 2013) is to oppose the arrival of tar sands crude in Quebec via the Line 9 and Energy East pipeline projects.[25]

5.3. Increases in Rail Capacity

5.3.1. Introduction

The Market Analysis asserts that rail can be implemented at sufficient scale and speed to transport all incremental tar sands production to markets, even absent any additions of new pipeline capacity (p. 1.4.1):

> Rail and supporting non-pipeline modes should be capable, as was projected in 2011, of providing the capacity needed to transport all incremental Western Canadian and Bakken crude oil production to markets if there were no additional pipeline projects approved.

The Market Analysis claims that activities are presently underway to enable large-scale utilization of rail to move tar sands crudes, and there has already been a sharp increase in transport of crude oil (p. 1-4-33):

> ***Increases in Rail Capacity***
>
> While no new pipeline capacity has been added since 2011 across the Canada-United States border or to the Canadian West Coast, the development of rail as a viable, large-scale transport option for crude oil does potentially add significant transport capacity along these and other routes. [footnote 28 in original omitted] As noted in the Final EIS, the linear infrastructure (railroad tracks) necessary to transport crude oil in large volumes out of the WCSB is already in place. **To**

[24] http://docs.house.gov/meetings/IF/IF03/20130410/100616/HHRG-113-IF03-Wstate-JaccardM-20130410.pdf pp. 3-4.

[25] http://marchepourlaterre.org (French website).

> **utilize rail at large scale, producers and/or shippers would need to build loading and unloading facilities and add tank car capacity. Both of those activities are presently underway, and there already has been a sharp increase in rail transport of crude oil. The developments to date, as well as a review of industry information, indicate that, especially as long as pipeline capacity is constrained, significant quantities of crude oil will be transported by rail, including out of the WCSB.** (emphasis added)

Meanwhile, a much more tentative assessment of tar sands crude by rail has been provided by the Alberta ERCB (Energy Resources Conservation Board, the provincial energy regulatory agency for tar sands and other energy resources). As part of its annual energy outlook, ERCB found that:[26]

> Rail shipments still represent a small portion of total volumes of crude bitumen moved. Currently rail is being used to service projects with limited pipeline capacity or to export volumes to areas not serviced by pipeline. This may change in the future. Rail transportation is being promoted as an economic alternative to pipelining oil and provides an option for producers to send oil to markets other than Cushing, where oversupply is occurring.
>
> […]
>
> In the short term, it is anticipated that rail will serve as a complementary niche used by industry, depending on economic factors unique to each producer and refiner. Rail could allow producers to bypass short-term pipeline bottlenecks to take advantage of higher prices in PADD areas with refineries capable of handling heavier crudes.
>
> Longer term, however, growth in shipments of bitumen by rail will depend on several factors, such as the availability and supply of diluent, the prices offered by other commodity producers already using rail, and the development of crude oil handling facilities to fill cars with bitumen.

The ERCB assessment is broadly consistent with the research that TGG was able to conduct within the constraints of the DSEIS process. To date, there has been only limited implementation of crude by rail in Western Canada. And much of that implementation is of limited (if any) relevance for demonstrating that crude by rail is a realistic alternative to the proposed Project (and other major pipelines).

[26] ERCB ST98-2012: Alberta's Energy Reserves 2011 and Supply/Demand Outlook 2012–2021 Energy Resources Conservation Board. June 2012, p. 3-37. Website: http://www.ercb.ca/sts/ST98/ST98-2012.pdf

The DSEIS Market Analysis of crude by rail is flawed and potentially misleading. And these flaws are not merely of academic concern, but instead feed into other aspects of the DSEIS that are also flawed and do not provide sound basis for analysis and decision-making.

5.3.2. Critique of Market Analysis Figure 1.4.6-5

Based on apparently very limited and flawed information and analysis, the DSEIS estimates that there are 15+ unit train loading facilities in the WCSB (p. 1.4-42, emphasis added):

> Figure 1.4.6-4[27] [sic] shows the estimated **unit train** loading, off-loading, and transloading facilities throughout North America for crude oil and their estimated capacities in 2013 and 2016. […] **There is less publicly available information about the facilities in the WCSB, including about their capacities.**
>
> […] **The number of facilities and capacities listed in the figure are primarily for facilities reported to be capable of handling unit trains.** [,,,] Section 1.8 of Appendix C, Market Analysis Supplemental Information, provides additional information related to these facilities and their estimated capacities and start-up dates.

Figure 1.4.6-5 specifies 2013 capacity of 240,000 bpd for 15+ Canadian loading facilities, but the DSEIS provides no basis for this capacity estimate. The DSEIS (quoted above) refers to Section 1.8 of Appendix C as providing additional information. However, there is no Section 1.8 in Appendix C.[28] Section 7 of Appendix C does provide information on crude by rail facilities in the US and Canada. For Canada (Table 14), 14 loading facilities are identified by location, but no information is shown for capacity and in-service date, and thus no basis is provided for the capacity estimate in Figure 1.4.6-5 for Canadian loading facilities.

The information provided in the DSEIS is not sufficiently specific to facilitate meaningful review in regard to Canadian train loading facilities.[29] Operator/owner is specified for only 10 of the 14 facilities listed in Appendix C, Table 14; 4 of the facilities are identified only by location. [30] The

[27] The reference here is actually to Figure 1.4.6-5 (which provides data for estimated capacities in 2013 (and 2016 for US facilities), not to Figure 1.4.6-4 (which provides data for 2010).
[28] In Appendix C (p. 1), Section 1.0 is immediately followed by Section 2.0.
[29] Source listed for Figure 1.4.6-5 is "Hart 2012; company and media reports." Source listed for Appendix C, Table 14 is "Hart 2012a; Hart 2012b; company and media reports." Hart 2012/2012a and 2012b are proprietary studies that are not publicly available; these were requested from Department of State, but they have not been provided (as of the time when this report was prepared). Source listed as "Company and media reports" is not sufficiently specific to facilitate meaningful review of the DSEIS Market Analysis in regard to Canadian train loading facilities, especially given that the DSEIS does not even specify ownership information for some of these facilities (see footnote 30).
[30] 4 Saskatchewan facilities are identified only by location: Dollard, Lloydminster, Esevan, and Bromhead. Meanwhile, there seems to have been some double counting. Table 14 includes "Torq Transloading, Tribune, SK" as a separate facility. Bromhead and Tribune are adjacent, and the Torq Transloading facility is in Bromhead. Torq (footnote continued on next page)

DSEIS (quoted above) states that Figure 1.4.6-5[31] shows information for capacities in both 2013 and 2016. But for Canadian facilities, estimated capacities are shown only for 2013. [32] Based on the independent review that TGG has been able to undertake within the constraints of the DSEIS process, publicly available information largely refutes, rather than confirms, the information in Figure 1.4.6-5 regarding Canadian facilities.

As a simple consistency check, it is useful to consider the average capacity of train loading facilities. According to Figure 1.4.6-5, there are 15+ Canadian Loading Facilities, with a 2013 capacity of 240,000 bpd, indicating that these facilities have an average capacity of less than 16,000 bpd.[33] Meanwhile, also according to Figure 1.4.6-5, there are 15 US Bakken Loading Facilities, with a 2013 capacity of 1,215,00 bpd, indicating that these facilities have an average capacity of 81,000 bpd; average capacity could increase to almost 100,000 bpd as these facilities continue to expand.[34] Put simply, the US Bakken has many large facilities for loading unit trains, but Canada does not. None of the Canadian loading facilities identified in the Market Analysis (Figure 1.4.6-5 and Appendix C, Table 14) are now unit train capable.

In fact, the loading facilities now available in Western Canada are smaller scale manifest train loading facilities, mostly proximate to non-tar sands production in Saskatchewan and adjacent areas of Alberta.[35]

(footnote continued from previous page)
Torq Transloading. 2012. Resource and Contract Requirements Necessary to Make Rail a Fully Integrated Part of Crude Takeaway Infrastructure. Presentation at the Crude Oil Markets, Rail & Pipeline Takeaway Summit. Calgary, AB. October 24 & 25, 2012, Adobe p. 5.

[31] See footnote 27.

[32] For US facilities, Figure 1.4.6-5 shows estimated capacities for both 2013 and 2016. The inadequacy of the DSEIS information and analysis in regard to Canadian crude by rail facilities is underlined by the contrast with the DSEIS in regard to US facilities. For each US facility (Appendix C, Tables 6-13), owner, location, estimated capacity and in-service date are specified, with estimated capacity then totaled for each type of facility, providing a reviewable basis for the summary data reported in Figure 1.4.6-5 for both 2013 and 2016.

[33] Figure 1.4.6-5 reports there are 15+ Canadian facilities. Based on the low end of this range (15 facilities), average size is 16,000 bpd (= total capacity / number of facilities). Based on a higher number of facilities, average size would be less than 16,000 bpd.

[34] Figure 1.4.6-5 indicates that capacity for the 15 Bakken Loading Facilities capacity could grow to 1,4865,000 in 2016, indicating an average capacity of almost 100,000 bpd. According to Appendix C, Table 7, 225,000 of this additional capacity is estimated to be added in 2014.

[35] http://www.rbnenergy.com/crude-loves-rocknrail-bitumen-by-rail-part-2
http://www.rbnenergy.com/crude-loves-rock-n-rail-plethora-in-the-williston-basin
These sources indicate that some development of unit train loading facilities may now be starting in the WCSB, but that is in Saskatchewan for light Bakken crude.
For each loading facility, these above two sources specify type: transload (manifest train) or unit train. According to the second source, the Crescent Point loading facility in Stoughton, Saskatchewan has a capacity of 8.000 bpd. This facility, which came on-line in February 2012 to serve Bakken production, has now been expanded to 45,000 bpd, with actual throughput continuing to ramp up.
Crescent Point Energy. Press Release: Crescent Point Energy Corp. Announces Year-End 2012 Results. March 14, 2013, Adobe pp. 2-4, 8
Website: http://crescentpointenergy.mwnewsroom.com/Files/c9/c9780fae-3b92-44a0-977b-6f4c79061fb0.pdf.
(footnote continued on next page)

5.3.3. Critique of Market Analysis Table 1.4-9

Together with dramatically overstating the extent of unit train facilities (Figure 1.4.6-5), the Market Analysis dramatically overstates the extent of crude by rail activity by tar sands producers. The Market Analysis claims that there are 8 tar sands producers currently shipping or planning to ship heavy crude in 2013:

> at least eight publically reported WCSB producers are currently shipping or have announced shipping **heavy crude** by rail in 2013 (Table 1.4-9).[36]
>
> As noted in Section 1.4 there are **at least 8 oil sands producers** that are currently transporting WCSB heavy crude by rail and have publically announced plans to transport increasing amounts of it by rail in 2013 (see Table 1.4-9). This indicates that shippers should have a choice in the form they ship crude oil and that they are already making plans to utilize the rail option at scale. [37]

As explained in more detail below, Table 1.4-9 does <u>not</u> actually present information for 8 tar sands producers that are currently transporting WCSB heavy crude. Crescent Point Energy, the largest single shipper identified in Table 1.4-9 (accounting for roughly one-third of the total volume in the table) is not a tar sands producer and it is not transporting heavy crude by rail. Crescent Point Energy produces lighter non-tar sands crudes (mainly in Saskatchewan from tight oil in the Canadian Bakken and Shaunovon), and its crude by rail relates solely to these lighter non-tar sands crudes. [38] Cenovus is a tar sands producer, but its crude by rail relates solely to lighter non-tar sands crude production. Baytex and Devon are also tar sands producers, but their crude by rail relates (in part) to other heavy non-tar sands crude production. Suncor is a tar sands producer, but its crude by rail relates (in whole or part) to supplying its Montreal refinery with lighter crudes (perhaps including non-tar sands production, as well as Suncor tar sands SCO).

Given the incomplete and potentially misleading data presented in Table 1.4-9, it is impossible to determine how much of the crude by rail is actually relating to tar sands heavy crudes, but it appears to be quite small overall. To date, transport of tar sands heavy crudes via rail has involved low volume operations, with niche players focusing on niche markets (small producers supplying specialized markets). This is the reality, and it is consistent with the assessment presented by ERCB.[39]

(footnote continued from previous page)
Accessed April 18, 2013.

[36] DSEIS, p. 1.4-43, emphasis added.

[37] DSEIS, p. 2.2-8, emphasis added.

[38] Incidental to its non-tar sands light crude production in Saskatchewan and Alberta, Crescent Point Energy produces a minor amount of heavy crude, about 1% of total crude output.
2012 Annual Information Form, p. 34. http://www.crescentpointenergy.com/files/10941.CPG-2012-AIF.pdf

[39] See footnote 26.

Table 1.4-9 includes data for the entire WCSB (Western Canadian Sedimentary Basin) and is thus much broader than just the Alberta tar sands in terms of geography, crude production, crude types, and other factors affecting the economics and potential for crude by rail. Put simply, the information in Table 1.4-9 is of quite limited value, and possibly misleading, in regard to assessing the potential for crude by rail to be a viable alternative to the proposed Project (KXL). Put simply, the actual crude by rail activity now underway in Western Canada bears little resemblance to the large-scale transport of heavy crude by rail presented in the Market Analysis as an alternative to the proposed Project.

In order to evaluate this important issue, TGG undertook a detailed analysis of Table 1.4-9. The results of this analysis are presented below, organized by crude producer.

5.3.3.1. Crescent Point

In Table 1.4-9, the largest single shipper identified is Crescent Point, accounting for roughly one-third of the total volume identified for all shippers in Table 1.4-9. Crescent Point is not a tar sands producer. Crescent Point has growing light (non-tar sands) crude production mainly in Saskatchewan (notably tight oil in the Canadian Bakken and Shaunovon). Crescent Point crude by rail relates solely to these lighter non-tar sands crudes and mostly to the Canadian Bakken.[40] The crude by rail in Table 1.4-9 for Crescent Point is similar to that in the adjacent US Bakken, as opposed to the large scale tar sands heavy crude by rail that the DSEIS assumes to be a viable alternative to the proposed Project.

5.3.3.2. Cenovous

While Cenovous is best known as a major tar sands producer and refiner, it also has growing light (non-tar sands) crude production in Saskatchewan and Alberta (notably tight oil in the Canadian Bakken). Cenovous crude by rail relates solely to these lighter non-tar sands crudes, and (in part) is being used to access markets, which are not now served by the crude pipeline network, notably to the East Coast. [41] The crude by rail in Table 1.4-9 for Cenovous is more similar to that in the adjacent US Bakken, than to the large scale tar sands heavy crude by rail that the DSEIS assumes to be a viable alternative to the proposed Project.

[40] Crescent Point has 3 rail loading facilities: 45,000 bpd at Stoughton (eastern Saskatchewan), 5,000 bpd at Dollard (western Saskatchewan), and 3,000 bpd at Viking (eastern Alberta near Hardisty). Crescent Point Energy, Corporate Presentation, March 2013, pp. 5-6, 17
http://www.crescentpointenergy.com/files/10939.CPG-2013-03.pdf

[41] Crude by rail is supplying the Irving refinery in Saint John, New Brunswick.
Healing, Dan, Cenovus expands rail shipments of oil, Calgary Herald, January 8, 2013
Website: http://www.calgaryherald.com/business/Cenovus+expands+rail+shipments/7791390/story.html Accessed April 14, 2013.
Cenovous, FirstEnergy Capital East Coast Energy Conference Presentation, March 14, 2013, p. 8
http://www.cenovus.com/invest/docs/2013/first-energy-2013-BCF-HSC-final-handout.pdf
Cenovous 2012 Annual Report, pp. 6, 46-47
http://www.cenovus.com/invest/docs/2012-annual-report/cenovus-AR-2012.pdf

5.3.3.3. Baytex

Baytex is a tar sands producer, but also has significant other heavy (non-tar sands) crude production in western Saskatchewan and eastern Alberta (Lloydminster and neighboring areas); Baytex crude by rail relates (in large part) to this other heavy non-tar sands crude production.[42] For various reasons discussed below, this other heavy non-tar sands crude production is in some ways similar to that in the US Bakken and otherwise better suited for crude by rail vs. tar sands heavy crude production.

Some Baytex Peace River tar sands production is being transported by rail, but this is a relatively low volume operation that is not pipeline connected. Baytex relies on trucking to move production from plantgate to either pipeline or rail loading terminal, which thus facilitates transporting undiluted bitumen. Thus, the crude by rail in Table 1.4-9 for Baytex is of limited relevance for evaluating the large scale tar sands heavy crude by rail that the DSEIS assumes to be a viable alternative to the proposed Project.

5.3.3.4. Devon

Devon has some tar sands production, but also has significant other heavy (non-tar sands) crude production in western Saskatchewan and eastern Alberta (Lloydminster area); Devon crude by rail may relate to this other heavy non-tar sands crude production, rather than Devon's pipeline connected tar sands production.[43]

5.3.3.5. Suncor

Suncor is a major tar sands producer, which upgrades most of its bitumen production into light crude (synthetic crude oil, SCO); in 2013, Suncor plans to transport Western Canada crudes via rail to its Montreal, Quebec refinery.[44] The Montreal refinery does not have coker capacity to process heavy crudes, and is otherwise configured to process a light crude slate. Based on the limited publicly available information, Suncor crude by rail relates (in whole or part) to light crude production, which is in some ways similar to that in the US Bakken and otherwise better suited for crude by rail vs. tar sands heavy crude production.[45] Thus, the crude by rail in Table 1.4-9 for

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[42] Baytex Energy. 2012 Annual Information Form, pp. 47-52. Website: http://www.baytex.ab.ca/files/pdf/investor-relations/Annual%20Information%20Forms/2012%20AIF.pdf. Accessed April 17, 2013;
Presentation, RBC Capital Markets' Crude and Refined Investor Day, April 4, 2013, pp. 3-5, Slides 6-10, "Rail Volume […] From Six different production areas […] At Six different loading locations"
Website: http://www.baytex.ab.ca/files/pdf/corporate-presentations/Baytex%20-%20RBC%20Heavy%20Oil%20Conf%20-%20Website.pdf . Accessed April 18, 2013.

[43] Devon Energy, 2012 Form 1-K, pp. 5, 7, 24
Website: http://services.corporate-ir.net/SEC/Document.Service?id=P3VybD1hSFIwY0RvdkwyRndhUzUwWlc1cmQybDZZWEprTG1OdmJTOWtiM2R1Ykc5aFpDNXdhSEEvWVdOMGFXOXVQVkJFUmlacGNHRm5aVDA0TnpReU9EVXdKbk4xWW5OcFpEMDFOdz09JnR5cGU9MiZmbj1EZXZvbkVuZXJneUNvcnBvcmF0aW9uXzEwS18yMDEzMDIyMS5wZGY=

[44] Suncor, 2012 Annual Report, pp. 7, 22, 28-29, 32, 40. Website: http://www.suncor.com/en/investor/3342.aspx?id=1599667&linkid=hIR-Q3. Accessed April 18, 213.

[45] Suncor is planning to transport Western crudes via crude by rail to an eastern refinery (Montreal); large amounts of crude by rail (notably from US Bakken) are being transported to East Coast refineries in US PADD 1 and New Brunswick (DSEIS pp. 1.4-37, 58, 61).

Suncor appears to be of limited relevance for evaluating the large scale tar sands heavy crude by rail that the DSEIS assumes to be a viable alternative to the proposed Project.

Moreover, Suncor plans to use crude by rail as a complement to pipelines, not a substitute. Suncor is a committed shipper on the Enbridge Line 9 project, to supply the full requirements of the Montreal refinery. As is the case for other major tar sands producers, Suncor has a strong preference for pipelines and is very active in promoting pipeline development.

5.3.3.1. Southern Pacific

Southern Pacific is a small tar sands producer and is transporting heavy tar sands crude by rail, via relatively complex logistics which also include trucking from plantgate and barge:[46]

> Southern Pacific's bitumen volumes will be trucked approximately 60 km (38 miles) from the STP-McKay plant gate to Lynton, Alta., a CN rail terminal located immediately south of Fort McMurray. From Lynton, volumes will be transferred into rail cars and shipped approximately 4,500 km (2,800 miles) over CN's network and a short-line rail partner to a terminal in Natchez, Miss. The bitumen will then be transferred to barges that will deliver the product as feedstock to refineries on the Gulf Coast.

Southern Pacific is a relatively small tar sands producer, with new production ramping up over at least the next year:

> Initial production at the firm's steam-assisted gravity drainage (SAGD) facility 45 km northwest of Fort McMurray was 1,200 barrels per day in December. It could take at least another year before the design capacity of 12,000 bpd is achieved.

Costs for these logistic are reported to be $31/barrel vs. $8 for pipeline (if it was available), although there could be some savings from backhauling diluent.[47]

To summarize, while Southern Pacific is a tar sands heavy crude producer, it is in some ways also similar to the light crude producers in the Bakken (and elsewhere) that have been big users of crude by rail. Compared with large tar sands producers, these other crude producers (notably Southern Pacific and Bakken) place a high value on flexibility and optionality, and also would prefer to avoid making large, inflexible commitments (such as for pipelines).

5.3.4. Locational and Logistical Factors for Crude by Rail

Location and logistics differ for Western Canadian crude production from non-tar sands and tar sands, such that non-tar sands production is better suited for crude by rail. Non-tar sands crude production in Saskatchewan and Alberta is located to the east and south of tar sands production, and is thus more proximate to both the existing rail network and destination markets.

[46] Press Release. http://www.shpacific.com/en/news/stp-2012-06rail7-june_27-final.pdf
[47] http://www.edmontonjournal.com/business/Alberta+bitumen+makes+Mississippi+rail/7785676/story.html

And as is also the case for Bakken light crude production, Saskatchewan and Alberta non-tar sands crude production is geographically dispersed over a wide area and often utilizes trucking for local collection, with crude then transferred onto either rail or pipelines. This dispersed pattern of production is proximate to the extensive rail network in the more southerly portions of Saskatchewan and Alberta, and this incentivizes development of multiple dispersed train loading facilities in order to reduce trucking requirements.[48] Heavy crude production that utilizes trucking for local collection also provides optionality for onward transport of crude that is undiluted (raw bitumen) or under-diluted (railbit), which may be preferred by refiners and especially those specializing in asphalt production.[49]

Crude production that utilizes trucking for local collection, and more generally small scale movements of crude by rail, preferences use of manifest trains, and thus smaller scale manifest train loading facilities.[50] Large scale movements of crude by rail between high volume production and destination markets enables the use of unit trains, and thus larger scale unit train loading facilities.

The Market Analysis relies upon recent experience in the Bakken (and in other new US production areas) as demonstration that crude by rail will be implemented rapidly and at very large scale to enable increases in crude production absent sufficient pipeline capacity:

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[48] Torq Transloading. 2012. Resource and Contract Requirements Necessary to Make Rail a Fully Integrated Part of Crude Takeaway Infrastructure. Presentation at the Crude Oil Markets, Rail & Pipeline Takeaway Summit. Calgary, AB. October 24 & 25, 2012, pp. 6, 20.

[49] Refineries specializing in asphalt production are a relatively small niche market, with significant seasonal variation (reflecting that asphalt is used in road and other projects that vary seasonally). Nonetheless, asphalt refineries may be an attractive niche market for heavy non-tar sands crudes, which may be well suited for asphalt production (as compared with heavy tar sands crudes, notably mined bitumen, whose asphalt quality may be poor).
Baker Hughes. 2010. Planning Ahead for Effective Canadian Crude Processing, p. 4 , "Asphalt from mined bitumen may be poor quality. SynBit asphalt quality uncertain."
Website: http://c14503045.r45.cf2.rackcdn.com/v1/8d19146939cbb609c9bcee0e9cf72dd2/28271-canadian_crudeoil_update_whitepaper_06-10.pdf. Accessed April 17, 2013
http://www.exxonmobil.com/crudeoil/download/KearlOilSands_withAssay.pdf p. 4, showing asphalt properties for Kearl and Cold Lake crudes.
Torq Transloading. 2012. Resource and Contract Requirements Necessary to Make Rail a Fully Integrated Part of Crude Takeaway Infrastructure. Presentation at the Crude Oil Markets, Rail & Pipeline Takeaway Summit. Calgary, AB. October 24 & 25, 2012, pp. 6, 10-11;
Vanderklippe, Nathan. Rail makes big inroads in oil transport. The Globe and Mail, May 21, 2012, updated June 21, 2012. Website: http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/rail-makes-big-inroads-in-oil-transport/article4198192/. Accessed April 16, 2013;
http://www.rbnenergy.com/crude-loves-rock-n-rail-east-coast-delivery-terminals
http://www.bloomberg.com/news/2012-05-03/nustar-may-triple-oil-rail-shipments-to-new-jersey-refinery.html
http://www.lloydminsterheavyoil.com/transporthistory.htm; and
http://www.heavycrudehauling.com/index.html

[50] Crude by rail via manifest shipments typically involves a smaller number of cars in a mixed train with a variety of goods and commodities. By comparison, crude by rail via unit train typically involves a full train (100 tank cars) cycling between unit train loading and unloading facilities.

> The leading production area that has developed rail, including the construction of dedicated terminals for loading unit trains [footnote 29 in original omitted] to transport crude oil, is in the Bakken in North Dakota and Montana. Pipeline capacity out of the Bakken has not kept pace with the increases in production in the region. **Rather than allow the production there to be shut-in, companies have responded with significant additional rail capacity and have been able to do so very rapidly.**[51]
>
> […]
>
> The Bakken area has seen the greatest construction of unit-train rail facilities to transport crude oil, but it is not the only area. Such facilities have been or are being constructed in virtually every new production area of the United States to transport crude oil where there is not sufficient pipeline capacity to accommodate the new production, including the Eagle Ford shale in Texas, the Permian basin in Texas, the Woodford/Anadarko area in Oklahoma, the Utica shale in Ohio, and the Niobrara shale in Colorado and Wyoming. [52]

The US Bakken is in some ways an ideal combination of characteristics for crude by rail.[53] Production is dispersed over a wide area and benefits from the development of multiple loading facilities. Producers place a high value on speed and optionality, At the same time, the overall scale of production is very large and readily supports use of unit trains. So the Bakken is in some ways very decentralized, but still big enough to achieve economy of scale.

Western Canadian non-tar sands production is typically smaller scale than US production. But for the reasons discussed above, crude by rail may still be attractive for non-tar sands producers, even if they are not large enough to utilize unit trains.

Tar sands production is typically larger scale, more clustered, and reliant on pipelines for local collection, regional aggregation, and onward transport via the North American crude pipeline system.[54] Pipeline transport beyond tar sands production facilities (plant gate) typically requires that bitumen be diluted to meet pipeline specifications.[55] Tar sands heavy crude production

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[51] DSEIS, p. 1-4-33 (emphasis added).

[52] DSEIS, p. 1-4-36.

[53] Aside from locational and logistical factors discussed in this section, the US Bakken also has other characteristics that have preferenced crude by rail, including producing a very high quality light crude that can be processed at many refineries, including those on the East Coast which are not pipeline connected.

[54] Tar sands projects are pipeline connected via the regional networks of Enbridge, Inter Pipeline Fund, Pembina, and Access. http://www.enbridge.com/MediaCentre/News/regionaloilsandsAAG.aspx
http://www.interpipelinefund.com/operations/oil-sands-transportation.cfm
http://www.pembina.com/pembina/webcms.nsf/AllDoc/023585C87690673D8725778800596E97?OpenDocument pp. 11-15
http://www.accesspipeline.com/. See also ERCB 2012, pp. 3-33 -3-34 http://www.ercb.ca/sts/ST98/st98-2011.pdf

[55] The Enbridge MacKay River Pipeline is heated and insulated to enable transport of dry bitumen (with little or no dilution) from plant gate to an offsite terminal, where bitumen is diluted to pipeline specifications for onward (footnote continued on next page)

facilities are located in northern Alberta and are not highly proximate to the existing rail network. Heavy tar sands crude production is typically diluted for pipeline transport upstream of locations (such as Lloydminster), which are more proximate to the existing rail network. Thus, optionality for onward high volume rail transport of undiluted or under-diluted bitumen would require logistics that are substantially more complicated and possibly higher cost. Various configurations might enable rail transport of crude that is undiluted (raw bitumen) or under diluted (railbit), including the following: [56]

a) undiluted or under diluted bitumen transported by truck from plant gate to rail loading facility;
b) diluted bitumen transported by pipeline from plant gate to the rail loading facility, where it would be heated to vaporize the diluent, which would then be cooled into a liquid and transported via a separate pipeline back to plant gate for reuse;
c) undiluted/underdiluted bitumen transported by heated and insulated pipeline;[57]
d) development and rail loading terminals that are proximate to tar sands production., however, these locations are also less proximate to the existing rail network and destination markets, requiring longer and more expensive rail shipments, and (potentially) extending and upgrading the existing rail network.

It remains to be shown whether any of these configurations could provide a viable and cost-effective alternative to high volume transport of dilbit via pipeline, or even how competitive these configurations would be vs. transport of dilbit via rail.

To the extent that tar sands producers are moving crude by rail, it appears to have some or all of the following characteristics: smaller producer, non-pipeline connected/reliant on trucking, starting up new production, seeking to supply niche markets, strong preference and high value for flexibility and optionality. Thus, the tar sands producers that are most active in crude by rail have some characteristics that resemble other crude producers who have tended to find rail attractive, notably Bakken and other shale, and also geographically dispersed non-tar sands heavy crude production in Saskatchewan and Alberta. These types of crude producers may prefer rail, even if it is significantly more costly than pipelines.

(footnote continued from previous page)
transport on the Athabasca Pipeline; the MacKay River bitumen pipeline is 12-inch diameter and 22 miles long, and thus is a very small portion of the overall Alberta crude pipeline network (where bitumen must typically be diluted to pipeline specifications). The Echo Pipeline is also heated and insulated.
http://turbolab.tamu.edu/proc/pumpproc/P21/02.pdf
http://www.glowachpipecoatingconsultant.com/pdf/MacKay-River-Pipeline-High-Temperature-Pipeline.pdf

[56] Within the constraints of the DSEIS process, TGG was able to undertake only a limited preliminary analysis. Based on this analysis, there are several configurations that might enable rail transport of crude that is undiluted (raw bitumen) or under diluted (railbit); however, each of these configurations could be problematic in terms of being more complicated and/or higher cost than logistics based on transport of dilbit via pipeline and rail.

[57] See footnote 55.

5.4. Pipelines and Rail as Transport Options for Tar Sands

As noted in the Market Analysis (p. 1.4-27):

> Pipelines have long been the preferred method of transportation for crude oil producers and shippers for long-term, relatively stable commitments.

For a variety of reasons, pipelines are an especially preferred method for transport of tar sands production to markets. As discussed in Section 6, Alberta (and especially tar sands production) is very remote and landlocked. Western Canadian (and other nearby) crude markets are quite small. So as tar sands production has expanded, pipelines have been essential to provide dependable, low cost transport of increasingly large volumes of crude over increasingly long distances.[58]

Pipelines are otherwise well matched to the needs of tar sands producers and shippers, because "long-term relatively stable commitments" [59] are highly preferred. As discussed in Section 6, tar sands production is capital intensive, and expansion projects typically entail large up-front investments. Moreover, many tar sands projects are individually quite large, take a long time to complete, and are vulnerable to major cost escalation and delays. Future revenues are highly uncertain and volatile, notably due to their linkage with crude prices, Future operating costs are also uncertain and potentially volatile, due in part to their linkage with energy prices.

Tar sands expansion is thus a risky business, and profitability is dependent upon a variety of short- and long-term factors, which (individually and in combination) are highly uncertain and volatile. Access to transportation capacity is vital for tar sands producers, since their revenues are dependent upon market access. Put simply, if crude cannot be transported to market, it has little (if any) value, and tar sands producers will have little (if any) revenue.

Potential transportation restrictions and consequent inability to generate revenue would be a problem for any business, but it would be catastrophic for the business model of tar sands producers. As discussed above, tar sands producers are in a capital intensive, high fixed cost business with long-lived assets, seeking to recoup large up-front costs by selling crude at a profit over many years. Thus, these producers want and need dependable access to transportation and markets, both short- and long-term. Put simply, their business depends upon it. In particular, adequate transportation and market access are a prerequisite for undertaking expansion projects.

[58] As tar sands production increases (and proximate markets remain small and saturated), crudes must be transported over longer distances to access less proximate markets. Moreover, as noted in the Market Analysis (p. 1.4-54), "[t]here has been a general trend in the outlook for oil sands production away from upgrading bitumen in recent years." Tar sands production is increasingly in the form of heavy crudes (bitumen), as opposed to light crudes (SCO). Thus, tar sands production must be transported to refineries that can process these crudes, notably to refineries with coking capacity (and other configuration such as metallurgy) required to process heavy tar sands crudes.

[59] DSEIS p. 1.4-27.

Tar sands producers recognize that crude transportation is a key consideration and pipelines are thus very important. Cenovous, a major tar sands producer, identifies Transportation Restrictions as a major operation risk and specifically states that approval of KXL (and the Northern Gateway Project will benefit heavy tar sands producers: [60]

> Our ability to efficiently access end markets may be affected by insufficient transportation capacity for our production. Transportation restrictions can negatively impact financial performance by way of higher transportation costs, wider price differentials, lower realized prices at specific locations or for specific grades and, in extreme situations, production curtailment. […] this risk […] has the greatest potential to impact our crude oil production, which could negatively affect our financial position, results of operations and cash flows within our Oil Sands and Conventional segments.
>
> […]
>
> **We anticipate transportation constraints will continue in the near term. The Keystone XL project and the Northern Gateway Pipeline project, if approved, will benefit heavy oil producers.**

The Market Analysis acknowledges that pipelines are a preferred method of crude transportation, but also asserts that crude by rail could provide a large-scale, viable alternative means of transporting tar sands crudes. In particular, the Market Analysis assumes that crude by rail could provide adequate transportation and market access, such that tar sands producers would continue to expand production absent KXL or even absent any new pipelines (p. 1.4-33):

> Rail and supporting non-pipeline modes should be capable, as was projected in 2011, of providing the capacity needed to transport all incremental Western Canadian and Bakken crude oil production to markets if there were no additional pipeline projects approved.

At best, the scenario of rail development suggested by Market Analysis is an untested hypothetical. To date, there has been only a small amount of tar sands crude by rail. And this is not surprising, given the needs and preferences of tar sands producers. When interviewed last year, Cenovus CEO Brian Ferguson characterized crude by rail as a short-term solution for small volumes, but made clear that large scale crude production and transport will require pipeline connections.[61]

> In rough terms, it costs twice as much to ship oil by train, some $5 to $10 more a barrel.

[60] Cenovous 2012 Annual Report, p. 63 (emphasis added) http://www.cenovus.com/invest/docs/2012-annual-report/cenovus-AR-2012.pdf

[61] Vanderklippe, Nathan. Rail makes big inroads in oil transport. The Globe and Mail, May 21, 2012, updated June 21, 2012. Website: http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/rail-makes-big-inroads-in-oil-transport/article4198192/ (emphasis added). Accessed April 17, 2013.

> The cost has made companies skeptical. Cenovus, which is boosting its daily train movements from 2,000 to 5,000 barrels this year, has supported two new pipeline proposals to move oil to the West Coast, for example.
>
> **Chief executive officer Brian Ferguson calls rail "really interesting" and a "good short-term solution for relatively small volume." But "anything of size in terms of shipments will require pipeline connections."**

Dr. Mark Jaccard, a leading authority on Canadian energy issues, has provided a similar assessment regarding the importance of KXL and other pipelines in regard to tar sands expansion.[62] He has reviewed the DSEIS Market Analysis and clearly concludes that KXL will substantially affect tar sands development:

> The Draft Supplemental Environmental Impact Statement of the US State Department assumes that denying the Keystone XL pipeline will not appreciably slow development of the Alberta oil sands and the carbon pollution it produces. There is considerable evidence that contradicts this assumption, and its importance is noted by industry analysts, Canadian politicians and even the oil sands producers themselves.
>
> Quite simply, in the absence of Keystone XL, oil sands producers will find it more difficult to profitably get their product to market. Over the next two decades, the oil sands industry is considering plans to triple its production. To move forward, these projects require a significant expansion of low cost transportation infrastructure. They have potential alternatives to Keystone XL, but these are more costly and more difficult to scale-up to the capacity of Keystone XL, and each faces significant impediments.
>
> **Because of their large capacity and low cost, pipelines are preferred.** [63]
>
> […]
>
> Notably, the lowest cost and highest volume method of transporting oil sands product is via pipelines, yet the other two major proposed pipelines from the oil sands – both of

[62] Dr. Jaccard is (among other things) an international energy and environmental expert and author, an energy economist, a professor of environmental economics at Simon Fraser University in Vancouver, as well as former head of the British Columbia Utilities Commission. Internationally, he is recognized for his work since the 1990s on the Intergovernmental Panel on Climate Change, which received the Nobel Peace Prize in 2007. He was also lead author on the IPCC's 2011 Special Report on Renewables. Thus, he has substantial experience and expertise regarding energy development, and specifically whether development of one type of project (notably pipelines) will affect development of another type of project (notably tar sands expansion).

[63] Jaccard, Mark, "Asking the wrong question about Keystone XL." Testimony to the US Congress Subcommittee on Energy and Power hearing entitled "H.R. 3, the Northern Route Approval Act." April 10, 2013, p.2 Website: http://docs.house.gov/meetings/IF/IF03/20130410/100616/HHRG-113-IF03-Wstate-JaccardM-20130410.pdf. Accessed April 19, 2013.

> them crossing British Columbia – are unlikely to be approved. **Denial of Keystone XL and both of these two pipelines will definitely slow development of the oil sands.**[64]
>
> […]
>
> This is not to say, however, that oil sands producers will stop pursuing new means of getting their product to market. Facing significant discounts for their product, some oil sands producers have turned to rail as a temporary solution. However, rail alternatives are more complicated and costly, and extremely difficult to scale-up to the level of throughput that would fully compensate for the absence of Keystone and either of the BC pipelines. Also, efforts to expand the use of rail for transporting bitumen will create its own counter pressure from concerned citizens along rail right-of-ways and trans-shipment hubs. [65]

As noted by Dr. Jaccard, tar sands expansion is affected by KXL as well as other major pipeline projects.

This does mean that there will be no development of crude by rail for tar sands. As discussed above, transportation restrictions are a major risk for tar sands producers. And these risks have intensified in the current context when pipeline capacity is highly constrained and may remain so. In this context, rail may play an important role as a contingency option.

Or put another way, rail may be attractive to tar sands producers as a form of transportation insurance, Moreover, rail might be a cost-effective as insurance, since it might have some other benefits, notably in terms of speed and flexibility to improve ongoing logistics. So to the extent that some rail capability is now being put in place (such as buying tankcars), this does not mean that a huge buildout of rail will be ongoing. Rail will only be useful as insurance if it is not relied upon as the base case option.

Long historical experience confirms that tar sands producers can and will undertake expansion premised on pipelines to provide high volume, low cost, highly dependable market access. The Market Analysis is based on the untested hypothetical that tar sands expansion could proceed based on just rail to transport expanding production to market.

Sole reliance on rail as a basis for tar sands expansion is a risky strategy for tar sands producers. As discussed in CIBC 2011,[66] tar sands expansion projects are large and subject to very large risk and uncertainties. Reliance on rail would further increase the risk and uncertainties for tar sands expansion. At a minimum, this added risk would have some impact on tar sands expansion, since producers would need to have a bigger economic cushion to justify proceeding with expansion projects.

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[64] Jaccard, *op. cit.*, p. 1.
[65] Jaccard, *op. cit.*, p. 3.
[66] P. 91.

5.4.1. Risk Factors Related To Crude By Rail

Beyond the flaws in the DSEIS analysis of rail discussed above, the DSEIS analysis also fails to take into account various risk factors related to crude by rail. These risk factors relate to the development of crude by rail (namely public opposition) and its operations (spills and increased regulation). These factors could (a) increase the cost of crude by rail beyond the DSEIS projections; and (b) represent significant impediments to this alternative to KXL. As such, the DSEIS assumptions regarding the availability and cost of crude by rail are, at best, an untested hypothetical and not a sound basis for decision-making.

According to Dr. Jaccard:

> Facing significant discounts for their product, some oil sands producers have turned to rail as a temporary solution. However, rail alternatives are more complicated and costly, and extremely difficult to scale-up to the level of throughput that would fully compensate for the absence of Keystone and either of the BC pipelines. Also, efforts to expand the use of rail for transporting bitumen will create its own counter pressure from concerned citizens along rail right-of-ways and trans-shipment hubs.

5.4.1.1. Risk factors Related to the Development of Crude by Rail

Tar sands developers have been frustrated by public opposition to pipelines and long regulatory delays in obtaining permits and approvals. As such rail has been touted as a good workaround to the protracted approval process and public controversy. Because permitting is not required to move crude by rail, some have assumed that moving crude by rail is as simple as getting a tanker car and loading it. Moreover tar sands developers have mistakenly assumed that there will be no public opposition to rail.[67]

However public opposition to crude by rail is growing in Canada in both the West and the East.[68] On Jan 29, 2013, 16 Canadian organizations, made up of environmental, First Nations, and citizen groups (including Greenpeace Canada and Sierra Club BC, Living Oceans Society, ForestEthics and the Council of Canadians) signed a letter to the CEO of Canadian National (Canada's largest railway) to express opposition any plans for the transport of tar sands crude by rail. The letter concluded with the following warning:

> "Should CN decide to try to move forward with its proposal, it would face major opposition and risks to the company. We urge you to stop any forward movement with shipping tar sands oil by rail through British Columbia."[69]

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[67] http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/with-pipelines-under-attack-railways-lead-race-to-move-oil/article7264773/

[68] http://www2.macleans.ca/2013/01/31/pipeline-opponents-say-cns-crude-by-rail-car-pitch-poses-risk-to-company/

[69] http://www.forestethics.org//sites/forestethics.huang.radicaldesigns.org/files/CN-Rail-letter-2013.pdf

Quebec is also mobilizing against rail as well as pipelines. As mentioned above, the theme of this year's Earth Day March in Montreal (on April 21, 2013) is to oppose the arrival of tar sands crude in Quebec. The French website mentions that opposition will be focused on arrival of tar sands in Quebec by either pipeline or rail.[70]

As discussed, pipeline opposition is nimble and dynamic and can quickly shift from project to project – or from pipelines to pipeline alternatives.

As such, US pipeline opponents can be expected to oppose crude-by-rail as an alternative to pipelines. Among the recent highly publicized string of crude oil spills in North America in spring 2013, several were caused by train derailments, including a Canadian Pacific derailment in Minnesota, which resulted in a spill of Canadian crude.[71] Dr. Jaccard's predicted "counter pressure from concerned citizens along rail right-of-ways and trans-shipment hubs" will get underway in the US should crude-by-rail start increasing.[72]

5.4.1.2. Risk factors Related to the Operations of Crude by Rail

As identified above, the risk factors related to operations of crude by rail include spills (resulting in damage to wildlife, ecosystems, property), and increased regulation. Rail routings often have particularly high proximity to water bodies and human and industrial activity, both absolutely and relative to typical routings for crude pipelines.[73] As such, rail spills can have significant impacts on waterways and in populated areas. The letter addressed to the CEO of Canadian National, cited above, points out the following:

> "Unfortunately, as a recent study by the think-tank the Manhattan Institute indicates, there are far greater fatality, injury and environmental risks when transporting crude oil by rail than by pipeline. The industry itself acknowledges that trains have nearly three times the number of spills as pipelines (which provides little comfort given Enbridge's oil spill record)."[74]

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[70] http://marchepourlaterre.org/

[71] http://www.reuters.com/article/2013/03/28/us-oil-train-derailment-idUSBRE92Q13U20130328

[72] Indeed, communities and indigenous groups in the Pacific Northwest have recently mobilized against coal by rail projects that affect their communities and may endanger fisheries. http://www.scientificamerican.com/article.cfm?id=local-opposition-stands-athwart-us-coal-exports-to-asia&page=2

[73] Especially for lines with heavy freight traffic, rail routings are designed to minimize elevation changes and were first established many years ago prior to most other infrastructure and development. Put simply, for rail routes, flatter is preferable, even if longer. As a result, rail routings are typically in low lying areas, often paralleling water bodies for long distances, in close proximity to shorelines and with many water crossings. Moreover, rail lines have historically had strong growth-inducing effects and often pass through populated areas and other concentrations of human and industrial activity. In comparison with the rail network, the crude pipeline network is less extensive and newer. Put simply, for pipeline routes, shorter is preferable, even if somewhat steeper. And especially for newer pipelines, routings may be designed to be somewhat less proximate to water and human activity.

[74] See Footnote 69, pp. 1-2. The Manhattan Institute study can be found at http://www.manhattan-institute.org/pdf/ir_17.pdf. The study compares the record of oil and gas pipelines to that of transport via rail and road and concludes that pipelines are significantly safer than rail and road.

The letter goes on to discuss CN's poor environmental and safety record, detailing major spills of toxic products in Illinois and consequent pollution of lakes and rivers and extensive damage to fish and wildlife.

The DSEIS does not appear to have taken into account the significant risk factors discussed above in its assumption of the availability and cost of crude by rail. As Jaccard points out, "rail alternatives are more complicated and costly, and extremely difficult to scale-up to the level of throughput that would fully compensate for the absence of Keystone and either of the BC pipelines." Mobilization is already gearing up to oppose crude by rail in Canada, and US activists are likely to also vigorously oppose this option should rail transport of crude increase. Moreover, due to the safety and environmental risks associated with this option, crude by rail could be subject to higher costs and potentially more regulation and public opposition in the future.[75]

5.5. Conclusion

The review of increases in pipeline and rail capacity in Section 5, demonstrates serious impediments to both pipeline expansion and crude by rail. TGG therefore rejects the key Market Analysis assumption that pipeline and other transport/takeaway capacity will not be a significant constraint on tar sands. Our evaluation concludes definitively that pipelines are by far the preferred transportation option for tar sands because of low costs and high capacity. However, the tar sands are now facing major constraints in terms of pipelines. Section 5.2 concludes that in light of increasing public opposition, there are uncertain prospects for all of the major proposed pipeline projects to transport tar sands crude. Section 5.3 then undertakes a detailed review of the DSEIS assumption that crude by rail can be implemented at a sufficient scale and speed to transport all incremental tar sands production to markets, even absent new pipeline capacity. This Section demonstrates the deep flaws in the DSEIS assumption regarding crude to rail. In fact, contrary to the assumptions of the Market Analysis, our evaluation in Section 5.4 concludes that crude by rail is not well-matched for the transport of tar sands crude in terms of both cost effectiveness and risk factors.

In demonstrating that there are serious impediments to other tar sands crude transportation options (including other pipelines and crude by rail), Section 5 makes a strong case that the approval of KXL matters - and it matters a great deal - for tar sands expansion.

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[75] Aside from crude, the rail network moves large amounts of other energy products, chemicals, and other hazardous materials.

6. Tar Sands Expansion and Breakeven Costs

6.1. Introduction

This section provides an appropriate framework for analyzing tar sands expansion and breakeven costs. Section 6.2 explores the important issue of how changes in logistics costs and crude prices affect the amount of tar sands expansion. Sections 6.3 and 6.4 look at how different market dynamics affect the relationship between crude prices and tar sands expansion costs. Tar sands breakeven costs are examined in Section 6.5 and the Markets Analysis assumptions are compared to other more recent data sources.

6.2. Sensitivity to Logistics Costs and Crude Prices

The Market Analysis (Vol I, pp. 1.4-51-1.4-55 and especially Figures 1.4.6-8 and 1.4.6-9) assumes that most tar sands projects likely have breakeven costs that are low relative to likely crude pricing, such that these projects will still be profitable with higher logistics costs[76]. However, the Market Analysis does then acknowledge that tar sands expansion is likely somewhat affected by changes in cost and crude prices (Vol I, pl. 1.4-55):

> Although it appears that most oil sands projects in the CAPP forecast (and the CIBC report) likely have breakeven costs low enough that the incremental increase in transportation costs would not drive project costs above the breakeven costs at expected oil prices, that does not mean that oil sands production would be completely insensitive to changes in costs (or the outlook in oil prices).

As a starting point, all else being equal, tar sands production and expansion will be more profitable with lower costs (including logistics costs) and/or higher crude prices. So with lower costs and/or higher crude prices, there will tend to be more tar sands expansion.

It is challenging to assess how much tar sands expansion will occur and how expansion could vary depending upon factors such as logistics costs and crude prices. There are a variety of interactions (such as construction costs), that in practice can vary substantially based on market conditions and have substantial effects on factors such as tar sands costs. Thus, the very simplified and static analysis shown in Figure 1.4.6-8 does not reflect the realities of tar sands economic factors and especially the highly interactive nature of those factors.

[76] In this report, logistics costs are defined as the costs associated with crude transportation.

In fact, across a very broad range of conditions and assumptions, changes in logistics costs and crude prices will impact the amount of tar sands expansion. In particular, it is not likely the case that in the future (at least any time soon) that tar sands expansion will be so profitable such that shifts in logistics costs and crudes prices (up or down) will not be a significant factor affecting tar sands expansion.

Thus, to the extent that KXL affects logistics costs (and/or crude prices), it will impact the amount of tar sands expansion, under a very broad range of conditions and assumptions. And this is the appropriate framework for assessing KXL impacts in this EIS process relating to a Presidential Permit application. KXL will have a substantial impact on tar sands expansion, and it should not be assumed away.

Notably, even if logistics costs are relatively low, and/or crude prices relatively high, there will still be tar sands projects whose profitability is marginal. In other words, there will be some projects that appear to be profitable (and producers will seek to build those), others with higher costs that do not appear to be profitable (which will not be built), and some projects that are right around breakeven. Thus, changes in crude prices and/or logistics costs can be assumed to have some impact on the amount of tar sands expansion.

6.3. Labor and other Alberta-Specific Constraints

In particular, in a context of high crude prices, costs for expansion projects will likely be higher, and possibly much higher, than in a lower crude price environment. As shown by past experience, high crude prices can lead to a high rate of tar sands expansion, as well as substantial cost escalation for tar sands projects. In part, this reflects Alberta-specific factors and bottlenecks, including a very small population, labor force, and economy, in a very landlocked location, with a cold climate that reduces productivity, in a country with a relatively small population, labor force, and economy overall. Alberta is a high-cost location for energy projects, and these costs can rapidly escalate when tar sands expansion ramps up to high levels. The concept of a tar sands supply curve is more complicated because project development (and operating) costs are affected by the amount of overall expansion. If many projects are developed at once, development (and operating) costs will spike up.

As explained in a recent CERA report:[77]

> **Rising Capital Costs**
> Cost is a barrier for new upgrading or refining projects in Alberta; when projects were first proposed (in the earlier 2000s), investors expected lower price tags. From 2000 to 2008 (as measured by the IHS CERA Capital Costs Index) costs for building upgraders or refineries in Alberta increased by 70%.[footnote * in

[77] IHS CERA, Extracting Economic Value from the Canadian Oil Sands: Upgrading and refining in Alberta (or not)?, March 2013, pp. 4, 9, 11, 15-16 http://www.ihs.com/images/ihs-cera-upgrading-refining-mar-2013.pdf

original omitted] The rate of change was borne out on actual projects built this decade, which had final price tags that were 50% to 100% higher than original estimates. Although costs softened during the recession, they have since recovered and are now higher than pre-recession levels. The situation is not unique to Alberta. Project costs around the globe registered similar escalation owing to increased demand for commodities, equipment, and specialized personnel. However, with absolute costs in Alberta already higher than most other regions, escalation had a more severe impact on project economics in Alberta. [footnote ** in original: Capital costs for Alberta oil sands have historically been higher than those for other regions, owing mostly to higher labor costs, lower labor productivity (stemming from extreme weather conditions), and challenges constructing in a remote landlocked location.]

[…]

• **Construction techniques.** Owing to differing construction methods, inland locations are more expensive to build. With ocean access, larger components or modules of the facility can be built off site. Once complete, the modules can be transported to site and assembled like building blocks. This technique materially reduces the labor requirements and—consequently—the cost. Access to the ocean is critical, because modules can be the size of a football field and need to be transported by ship. Although inland locations can use this method, since the modules must be transported by truck, this materially reduces the module size and corresponding cost savings.

• **Labor costs.** Construction labor is a large factor in why costs vary among regions. In North America direct labor typically makes up 30% of a project's total cost, and labor costs in Alberta are higher than those of other regions. One cause is the limited regional pool of construction workers (demand from oil sands projects often exceeds local supply, requiring workers to be recruited from across Canada and the globe). Another is Alberta's landlocked location, keeping on-site labor requirements relatively high (see construction techniques). Climate is also a concern; cold weather decreases worker productivity.

[…]

The Alberta labor limit

Alberta has a relatively small skilled trade workforce for constructing industrial projects—in our estimate about 17,000 workers are available for construction projects (welders, pipefitters, electricians, and other skilled trades) in Alberta. These workers support oil sands activity plus other industrial projects in the province, such as electrical generation, pipeline construction, infrastructure, and maintenance.

Often Alberta labor demand exceeds supply. Staffing industrial turnaround work (large maintenance projects that are periodically executed over a one- to three-month period in the spring and fall) is a perennial problem. To staff turnarounds, multiple projects demand thousands of skilled trade workers at the same time. During the turnaround seasons, workers from the rest of Canada are regularly called on. There were longer-term labor shortages in 2007 and 2008 when the demand for construction labor exhausted both Alberta and Canadian supply. Foreign workers were recruited to fill the gap. Now, once again, the Alberta labor market is constrained. Foreign workers are already at work on oil sands and other projects in the province, and their numbers are projected to ramp up over the next few years.

During the 2007 and 2008 labor shortage, projects faced expensive implications. Wage rates were one factor, increasing by 5.9% annually. [footnote * in original omitted] In addition total labor costs were boosted by overtime pay (over a 40-hour week, wages are paid at time-and-a-half and double rates), signing bonuses, employee recruitment costs, and living allowances. Worker productivity also took a hit: as the labor shortage grew, the average skill level of the workforce declined.

But perhaps the most costly implication of the shortage was the expensive start-up and operational issues that numerous projects faced. […]

to avoid the need for foreign workers and the costly implications of a labor shortage, the province should keep total construction labor demand at around 25,000 workers. At this level, workers from other parts of Canada are still required to support projects, although no more than what has historically been recruited. Since the demand from other Alberta industrial projects averages near 8,000 workers, this means that oil sands demand would need to stay near 17,000 workers.

Critical to our assumption that labor remains a long-term constraint to growth are the expectations that oil sands growth remains strong and that government policy for accessing foreign labor does not change significantly from today (i.e., existing barriers for accessing and keeping foreign labor in the province continue). [footnote * in original: In June 2012 the Canadian government changed the process for accessing foreign labor by introducing an accelerated labor market opinion process. The new process shortened the timeline, but it still takes a company 6 to 12 months to bring a new foreign worker to Canada. Other barriers include limits to the cumulative time that workers can stay in Canada and difficulty in immigrating.]

6.3.1. Comparison of Canadian and US Regional Economic Factors Impacting Energy Development

As explained above, tar sands projects are subject to a variety of factors that can result in intensive cost escalation, especially during periods when producers seek to rapidly ramp up production. Perhaps especially for those familiar with the US context, it is quite notable and illuminating that there are only about 17,000 Alberta construction workers available to work on tar sands construction projects. It is thus useful to compare Alberta and Texas, and more generally the two countries, in terms of how these differences affect energy development.

The US (and especially Texas) has traditionally been a global center for oil and gas industry. But with the growth of the tar sands and related activities, Canada (and especially Alberta) has emerged as another global center for the oil and gas industry. More generally, there are some substantial similarities and interactions between Canada (notably Alberta) and the US (notably Texas).

But while similar in some ways, Alberta and Texas actually differ quite dramatically in terms of scale, location, proximity, climate, and national setting. As a result, energy projects in Alberta are typically more costly compared with similar projects in Texas, and a high rate of activity in Alberta is much more likely to result in bottlenecks and substantial cost escalation. Put very simply, size and location matter for energy projects; in terms of economy and logistics, Alberta is very small and remote, and Texas is very large and proximate.[78] Even when viewed on a national scale in terms of economy and logistics, Canada is relatively small and in some ways logistically challenged, and the US is enormous and in some ways logistically advantaged.[79] And while current and evolving climate conditions affect energy projects in both Canada (notably Alberta) and the US (notably Texas), winter and other seasonal conditions typically result in higher costs for projects in more northerly locations.

[78] The population in the entire province of Alberta is less than 4 million vs. more than 6 million in just the Houston metropolitan area and 26 million in the entire state of Texas. Alberta is very landlocked and remote from tidewater and other population and economic centers. Texas has a lengthy coastline, extensive port facilities, and is otherwise locationally and logistically advantaged in terms of proximate and relatively low cost access to large markets in both the US and internationally.

[79] The population in all of Canada is less than 34 million vs. 315 million in the US. The Canadian population is less than the combined population of Texas and the two neighboring states that are also centers of the oil and gas industry (over 34 million in Texas, Louisiana, and Oklahoma). Canadian population and economic activity are mainly concentrated in the southerly areas within 100 miles to the US border, extending for almost 4000 miles between the East Coast (Atlantic) and West Coast (Pacific). But in part due to tar sands and other energy development, a significant portion of Alberta population and economic activity are located further north and less proximate to the US. In contrast with Canada, US population and economic activity are widely distributed across the lower 48 states, with concentrations proximate to tidewater (Atlantic and Pacific Oceans, Gulf of Mexico) and inland navigable waters (Great Lakes, as well inland rivers which in many cases are navigable for marine cargo vessels, albeit with some winter and other restrictions).

These differences between Canada and the US have important implications for energy development, as can be seen in regard to both tar sands and tight oil. In recent years, the US has achieved a ramp up in crude production that is substantially greater than the production increase in Canada. In large part, this reflects that tight oil development in the US has been able to achieve a ramp up in production that is much more rapid than that achieved by either tar sands or tight oil in Canada.[80]

Much of the increase in US crude production has occurred in Texas, and has been advantaged by proximity to labor, supply chain, and markets. But there have also been substantial crude production increases in other parts of the US (notably in North Dakota Bakken) that are more remote and logistically challenged. Nonetheless, even in those areas, energy development has been advantaged by availability of labor, supply chain, and markets in other parts of the US (including Texas).[81]

6.4. Crude Price and Other Broader Market Dynamics

The relationship between crude prices and tar sands expansion costs also reflects factors that are less location-specific, and more related to national, continental, and global market dynamics. Tar sands projects are materials and equipment-intensive. When crude prices are high, this puts upward pressure on tar sands Input costs (for steel, cement, and other supply chain), in part because higher energy prices will also tend to increase capital spending for energy projects outside Alberta. Also, tar sands projects are energy-intensive, for both construction (notably for energy as input for materials such as steel and cement) and operations (especially for in-situ production), and higher crude prices tend to coincide with higher energy prices overall.

Aside from the impact of crude prices upon construction (and operations) costs for tar sands projects, high crude prices and a high rate of tar sands expansion may also lead to higher logistics costs. As with tar sands projects, logistics such as pipelines and rail are materials-, equipment-, and energy-intensive for both construction and operations. But more generally, high crude prices and a high rate of tar sands expansion will typically coincide with a scenario with large and rapidly increasing requirements for logistics to transport crudes. Moreover, as tar sands production increases, it will tend to be accessing less proximate markets and thus crudes will need to be transported over longer distances.

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[80] http://media.argusmedia.com/~/media/Files/PDFs/Presentations/IP13-ArgusCrude.pdf Adobe pp. 2-4; CIBC 2012, pp. 72-75.

[81] As discussed in the IHS CERA report cited above (footnote 77), workers from other jurisdictions may be called in to mitigate local labor shortages. Labor markets are to some extent national, and to a lesser extent, international. Energy projects in the US typically have substantial access to sizable local and very large national labor supply, and a more restricted capability to use foreign workers. Energy projects in Canada have access to small local and relatively small national labor supply, and a more restricted capability to use foreign workers.

In a context of high crude prices, there may also be rapid growth and shifts in other crude production and logistics, which can place further pressures on the crude logistics system. In fact, this is now occurring in North America, with rapidly increasing light crude production from shale/tight oil occurring simultaneously with sizable growth in tar sands production.

Especially in a context where logistics are constrained (and potentially subject to major opposition and delays), a high rate of tar sands expansion (likely accompanying high crude prices) could result in higher effective logistics costs vs. a context of a lower rate of tar sands expansion (likely accompanying low crude prices).

The relationships discussed above are also relevant to more generally consider in terms of a context with low crude prices. In general, lower crude prices are not favorable for tar sands profitability and expansion. But the unfavorable impact of lower crude prices on tar sands profitability will be somewhat offset by the favorable impact of reduced costs for project construction, operations, and logistics. Put simply, with lower crude prices and a lower rate of tar sand production growth, tar sands costs will generally be lower. Moreover, in this context, producers will likely focus on the expansion project with the most favorable economics, which are more likely to be profitable even in a low crude price environment.

That said, if crude prices are low enough and/or logistics costs high enough, then tar sands expansion may largely or completely stop. Below a certain threshold, little if any expansion may be profitable. But given the low cost estimated for some tar sands projects and other interactive effects discussed above, some tar sands expansion might ongoing even with relatively low crude prices (and/or logistics costs relatively high).[82]

6.5. Tar Sands Breakeven Costs

The Market Analysis assumes that costs of new tar sands projects are moderate and increase at only the rate of general inflation. The Market Analysis relies on data from NEB 2011 (pp.1.4-51 – 1.4-52):

> The Canadian NEB in 2011 provided estimated breakeven costs for new tar sands projects. Those prices expressed in terms of WTI price in 2011 dollars were: $51–61

[82] In particular, in situ projects are typically estimated to have lower breakeven costs, relative to mining (non-upgraded) and upgraded mining. Likewise, it is sometimes estimated (notably in CIBC 2012) that there is a substantial range of costs for in-situ/SAGD projects, such that the lowest cost projects could be competitive at even relatively low crude prices. See:
National Energy Board (NEB). 2011. Canada's Energy Future: Energy Supply and Demand Projections to 2035, cited in DSEIS Table 1.4.10, p. 1.4-52; referred to in DSEIS Market Analysis and in this report as NEB 2011;
CIBC 2012, p. 90;
ERCB 2011 http://www.ercb.ca/sts/ST98/st98-2011.pdf
ERCB 2012 http://www.ercb.ca/sts/ST98/st98-2011.pdf

per barrel for new in-situ crude; $66–76 per barrel for mining (without upgrader); and $86–96 per barrel for mining (with upgrading) (NEB 2011).

The NEB 2011 estimates substantially understate likely breakeven costs, especially for scenarios with a high rate of tar sands expansion. The table below compares the NEB 2011 estimates with the breakeven cost estimates issued in 2011 and 2012 by the Alberta ERCB (Energy Resources Conservation Board), the provincial energy regulatory agency for tar sands and other energy resources.

Tar Sands Breakeven Costs (WTI Price $/barrel)			
Project Type	NEB 2011[83]	ERCB 2011 [84]	ERCB 2012[85]
New In Situ	$51 - $61	$47 - $57	$50 - $78
New Mining (no upgrading)	$66 - $76	$63 - $81	$70 - $91
New Mining w/ Upgrading	$86 - $96	$88 - $102	NA

As shown in the above table, breakeven costs estimated by ERCB in 2012 are substantially higher than those estimated in 2011 (by ERCB and NEB). In comparing its 2012 and 2011 estimates, the ERCB identified cost escalation as major risk factor for tar sands projects:[86]

> The significant cost inflation experienced by projects in the previous economic boom resulted in some operators delaying and deferring new projects. […]
>
> The results of the supply cost analysis show a marked increase over the results from last year. This increase is largely attributable to the forecast light/heavy differential and higher sustaining capital expenditures. […]
>
> **A major risk to the capital cost assumptions in this analysis would be the re-emergence of cost escalation that occurred in the last decade. When too many projects proceed, resources such as labour quickly become scarce, which results in an escalation in capital and supply costs.**

[83] 2011 $.
[84] ERCB 2011 does not specify, but data are presumably in 2011 $ (year report was issued).
[85] 2012 $. Values in 2011 $ would be approximately 2% lower.
[86] ERCB 2012, p. 3-30 (emphasis added).

As discussed in Section 6.3, Alberta is highly constrained in terms of labor and other resources required for tar sands projects. Alberta is a high-cost location for energy projects, and these costs can rapidly escalate when tar sands expansion ramps up to high levels. The ERCB 2012 cost estimates are substantially higher than those estimated in 2011 (by ERCB and NEB), but costs could actually be much higher. In a scenario of rapid tar sands expansion, costs escalate, sometimes leading to projects being delayed or canceled.

In evaluating industry growth forecasts for tar sands expansion, CIBC 2012 (pp. 88-90) considered labor availability:

> The […] major question mark for oil sands development is labor availability. The oil sands is a massively labor intensive project type. A typical 100,000 Bbls/d non-upgraded mine requires peak labor of approximately 5,000 workers. A typical upgraded mine can require anywhere from 5,000-10,000 peak labor force depending on pace of construction (historically peak was 10,000 but more companies are planning to stretch construction to have better work force control). SAGD is less labor intensive but, even still, a typical 35,000 Bbls/d SAGD project still requires a peak labor force of approximately 700 workers over a two- to three-year construction period (smaller projects at shorter end of scale) and with so many projects in the queue, the labor needs are still massive.
>
> The key takeaway is that to meet industry growth forecasts to the 2016/17 time frame, the available labor force in the oil sands would need to expand approximately 80% from 2012 levels. Clearly, at face value, these forecasts entail a massive external labor need – and we note this does not include the potential for the North West upgrader (potentially another 5,000 people) or competing labor demands for LNG construction on the BC Coast

CIBC 2012 (pp. 88-90) considered how crude prices and major development constraints (notably labor and pipeline capacity) will operate to balance supply and demand and limit tar sands expansion to an achievable level:

> **Prices/Costs & Pipelines Will Rationalize Development…It Is Only A Matter Of How Far**
>
> […] **there are a massive amount of projects on the planning board that cannot simply be taken at face value given the major development constraints such as pipeline capacity and labor.** This implies a need for major projection rationalization/ cannibalization that will be accomplished through some combination of accelerating inflation, lower prices or more stringent/discerning external capital.
>
> […]
>
> In an efficient market, price or costs will rationalize the supply/demand balance

– and oil sands is no exception. As recently as the 2005-2008 cycle, we saw inflating costs substantially rationalize the pace of planned oil sands development – and we will see that again.

To gauge potential price impacts, CIBC 2012 (pp. 89-90) estimated breakeven costs[87] and how those costs were sensitive to cost escalation and crude price differentials:

> To first gauge what the price impact is on oil sands development, we must understand the approximate break-evens. Exhibit 86 depicts the break-even oil price at today's cost for a variety of in situ and mining oil sands projects. **Recognizing that break-even costs are not a static figure, we also depict expected break-evens in five years assuming 5% per year cost inflation.** As depicted, there is wide range of outcomes. […]
>
> We also note that these break-evens are hyper sensitive to realized price discounts. For non-upgraded projects, the sensitivity relates to the light-heavy oil differentials. The aforementioned break-evens were assuming 20% WCS discount to WTI. If we increase the WCS discount to 25%, the break-evens increase to US$49/Bbl for a high-quality lease to as high as US$82/Bbl for lower-quality leases.

Exhibit 86. Oil Sands Break Even

$/Bbl Break Even Cost	15% WCS & 0% SCO Discount		20% WCS & 5% SCO Discount		25% WCS & 10% SCO Discount	
	Today	5-Years	Today	5-Years	Today	5-Years
Low Cost SAGD	$43.47	$47.95	$46.19	$50.95	$49.27	$54.34
Avg Cost SAGD	$56.02	$61.99	$59.52	$65.87	$63.49	$70.26
High Cost SAGD	$72.13	$79.60	$76.64	$84.57	$81.75	$90.21
Non-Upgraded Mining	$66.96	$76.67	$71.14	$81.47	$75.89	$86.90
Upgraded Mining	$83.30	$95.58	$87.68	$100.61	$92.56	$106.20

Source: CIBC World Markets Inc.

In comparison with the breakeven costs estimated by NEB 2011 and ERCB, the CIBC 2012 cost estimates are spread over a wider range (i.e. from highest to lowest costs). In part, this reflects that the CIBC estimates are based on a detailed review of specific projects, rather the more generic projects assumed in the other estimates. But the wide range also reflects that CIBC has attempted to capture some of the interactive effects.

The key takeaway is that tar sands economics are very dynamic and sensitive to a variety of factors. CIBC assumed 5% annual escalation, but costs could rise much faster a period of rapid tar sands expansion.

[87] As also discussed in DSEIS footnote 50 (p. 1.4-51), these breakeven costs for tar sands projects are expressed in terms of WTI, but the crude produced is heavy (WCS) for in-situ/SAGD and mining projects, or light (SCO) for mining/upgrading.

6.6. Conclusion

Section 6.2 concludes that across a very broad range of assumptions and conditions, changes in logistics costs and crude prices affect the amount of tar sands expansion. Thus, to the extent that KXL affects logistics costs (and/or crude prices), it will impact the amount of tar sands expansion under a very broad range of assumptions and conditions. Sections 6.3 and 6.4 demonstrate how different market dynamics affect the relationship between crude prices and tar sands expansion costs. In a context where logistics are constrained (and potentially subject to major opposition and delays), a high rate of tar sands expansion (likely accompanying high crude prices) could result in higher effective logistics costs. In contrast, a lower rate of tar sands expansion (likely accompanying low crude prices) could result in lower effective logistics costs. However, generally lower crude prices are not favorable for tar sands profitability and expansion.

These dynamics matter in terms of how KXL could have an impact on tar sands expansion. At high crude prices, access to a low-cost, high-capacity transportation option could facilitate maximum tar sands expansion since part of the constraint of higher logistic costs would be removed. At low crude prices, access to a low-cost, high-capacity transportation option could enable some of the less profitable marginal tar sands projects. Therefore across a broad range of conditions (high crude prices and high logistics costs to low crude prices and low logistics costs), KXL can enable tar sands expansion (at low crude prices and low-cost logistics) or maximize tar sands expansion (at high crude prices and high-cost logistics).

Tar sands breakeven costs are examined in Section 6.5, and the Market Analysis data is compared to other more recent data sources. Our evaluation shows that the DSEIS is relying on outdated information that substantially underestimates the breakeven costs for tar sands projects under emerging market conditions. As indicated above, under challenging economic conditions, it is even more essential for tar sands producers to have access to high volume, low cost logistics. Approval of KXL will have a significant impact as an enabler of less profitable marginal tar sands projects that could not be constructed without access to low-cost logistics.

7. KXL Impact on Tar Sands Expansion

It is reasonable to conclude the following as a basis for analysis and decision-making:

1) Across a very broad range of conditions and assumptions, changes in logistics costs and crude prices will impact the amount of tar sands expansion.

2) KXL, and specifically its impact on tar sands logistics costs and crude prices, will thus impact the amount of tar sands expansion.

In this context, it is important to determine what impact KXL has on tar sands logistics costs and crude prices. In practice, KXL is important for tar sands expansion, since it provides preferred pipeline logistics (high capacity, low cost, traditionally high reliability) to supply the US Gulf Coast (USGC) refinery market, and especially refineries configured to process heavy crudes.

Emerging market conditions may result in substantial downward pressure on netbacks[88] from selling heavy crude into the USGC market. In this context, tar sands crudes could be much more competitive with KXL than with other higher cost logistics. Or put another way, at enough of a price discount, tar sands crudes can be competitive to supply USGC markets, but this could result in a low enough net back to substantially constrain tar sands profitability and expansion.

The Market Analysis has assumed away the impact of KXL on tar sands expansion by concluding that KXL will not have substantial impact on tar sands production (and thus will not have substantial impacts on GHGs and other impacts associated with tar sands production).

Based on our evaluation of current market conditions (including emerging crude markets, factors driving tar sands expansion, availability and cost of crude oil transportation and tar sands breakeven costs), the TGG report concludes that the Market Analysis is deeply flawed and not a sound basis for decision-making. We have determined that KXL, and specifically its impact on tar sands logistics costs and crude prices, will have a significant impact on tar sands expansion under a very broad range of conditions and assumptions.

Given the limitations of the available data, time and resources, TGG is unable to precisely quantify the impact of KXL on the tar sands. This impact is difficult to quantify and would require a highly sophisticated analysis that examines a range of scenarios and many interactive effects (to model the dynamic market conditions that exist in the real world petroleum markets).

[88] Netback is a summary of all the costs associated with bringing one unit of oil to the marketplace, and all of the revenues from the sale of all the products generated from that same unit. The netback is calculated by taking all of the revenues from the oil, less all costs associated with getting the oil to a market. These costs can include, but are not limited to, importing, transportation, production and refining costs, and royalty fees.

However, for the purposes of providing practical guidance to policymakers, a conservative and credible estimate would be that KXL's effect on tar sands expansion would be 100% or 1:1. In other words, every barrel of tar sands crude transported by KXL would be the equivalent of a barrel of expanded crude production in the tar sands. Therefore, if at full capacity, KXL can transport 830,000 bpd of tar sands crudes, then its effect on tar sands expansion would be 830,000 bpd.

This estimate is based on our evaluation of current market conditions, and in particular on our analysis in Section 5 of the availability and cost of crude oil transportation. TGG has concluded that there are serious impediments to other crude transportation options (including other pipelines and crude by rail). This opinion has been substantiated by the recent testimony of energy expert Dr. Mark Jaccard[89] on KXL and CIBC 2012, both cited earlier in this document. In light of increasing public opposition, there are uncertain prospects for all of the major proposed pipeline projects to transport tar sands crude. Moreover, contrary to the assumptions of the Market Analysis, TGG has concluded in Section 5 that crude by rail is not well matched for the transport of tar sands crude, in terms of cost-effectiveness and risk factors.

The 100% impact of KXL is further support by TGG's conclusions in Section 4 regarding the crude markets. In this section, we demonstrate that the emerging economic conditions will become increasingly challenging for the tar sands. Under challenging economics conditions, it is even more essential for tar sands producers to have access to high volume, low cost logistics, so the impact of KXL on tar sands expansion tends to 100% under these conditions.

We are aware that under certain plausible scenarios, particularly those in which a modest amount of crude by rail is cost-effective, KXL's effect on tar sands expansion would somewhat less than 100% (i.e. less than 830,000 bpd), but we believe that the impact of KXL would continue to be quite substantial under most scenarios.

Furthermore TGG's evaluation of market conditions leads us to conclude that the 100% estimate is far more accurate than that of the Market Analysis, which assumes the following vastly underestimated impacts for KXL:

> If all such pipeline capacity[90] were restricted in the medium-to-long-term, the incremental increase in cost of the non-pipeline transport options could result in a decrease in production from the oil sands, perhaps 90,000 to 210,000 barrels per day (bpd) (**approximately 2 to 4 percent) by 2030**. If the proposed Project were denied but other proposed new and expanded pipelines go forward, the incremental decrease in production could be approximately 20,000 to 30,000 bpd (**from 0.4 to 0.6 percent of total WCSB production**) by 2030. (As examined in section 4.15, such production decreases would be associated with a decrease in greenhouse gas emissions in the range of 0.35 to 5.3 MMTCO2e annually if all

[89] See footnote XX.

[90] Referring to pipeline projects located exclusively in Canada (particularly, Northern Gateway, Trans Mountain and Energy East).

> pipeline projects were denied, and in the range of 0.07 to 0.83 million metric tons carbon dioxide equivalent (MMTCO2e) annually if the proposed Project were not built.)[91]

In light of our evaluation, TGG suggests that 100% impact estimate is a credible, conservative and pragmatic estimate to guide policymakers in the absence of a much more sophisticated analysis that examines a range of scenarios and many interactive market effects. However, should policymakers wish to base their decision on a more sophisticated analysis, we suggest that the TGG evaluation provided herein be used as input for such an analysis, which would also address and remedy the deep flaws identified in the DSEIS Market Analysis.

[91] Section 1.4.1 (pp. 1.4.1 – 1.4.-2). Emphasis added.

Appendix II

Air Quality Impacts of the Keystone XL Project at Refineries in PADD 3

Air Quality Impacts of the Keystone XL Project at Refineries in PADD 3

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April 22, 2013

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Figures and Tables

I. INTRODUCTION

The proposed Keystone XL project consists of an 875-mile long pipeline and related facilities to transport up to 830,000 barrels per day (BPD) of crude oil from Alberta, Canada and the Bakken Shale Formation in Montana. The pipeline would cross the U.S. border near Morgan, Montana and continue through Montana, South Dakota, and Nebraska where it would connect to existing pipeline facilities near Steele City, Nebraska for onward delivery to Cushing, Oklahoma and the Texas Gulf Coast region (Project).

I was asked to evaluate the air quality impacts at PADD 3 refineries from processing the Western Canadian Sedimentary Basin (WCSB) tar sands crudes that would be imported by this Project. My resume is included as Exhibit A to this report. I have worked on many heavy crude expansion projects, including the new tar sands refinery in South Dakota; tar sands expansion projects in Canada, Indiana, Michigan and Louisiana; an oil shale refinery in Colorado; and several heavy crude expansion projects in California and Texas, for both applicant/owners and others.

The Final Environmental Impact Statement (FEIS) and Draft Supplemental Environmental Impact Statement (DSEIS) do not evaluate air quality impacts of refining WCSB tar sands crudes, but rather set out excuses for failing to do so. These documents also do not contain the basic information required to prepare an air quality analysis.

In my opinion, based on my experience working on similar projects, the refining of up to 830,000 barrels per day (BPD) of WCSB crude in PADD 3 refineries would increase the amount of fuel that would be burned at nearly every fired source (heaters, boilers, flares, turbines) within receiving refineries and their off-site support facilities, compared to current crude slates. Further, pollutants in the diluent blended with these crudes would be emitted at nearly every single fugitive component, including compressors, pumps, valves, fittings, and tanks, in greater amounts than from other heavy crudes. This would result in significant air quality impacts including:

- causing or contributing to violations of National Ambient Air Quality Standards (NAAQS) of ozone in severe and marginal ozone nonattainment zones;
- increasing emissions of criteria pollutants, including nitrogen oxides (NO_x), sulfur oxides (SO_x), carbon monoxide (CO), volatile organic compounds (VOCs), particulate matter (PM10, PM2.5), hazardous air pollutants (HAPs), and highly odiferous sulfur compounds that would individually and cumulatively degrade ambient air quality and adversely affect the health of residents around the subject facilities;
- accelerate corrosion of refinery components, contributing to equipment failure and accidental releases.

According to the DSEIS, the Project would supply up to 830,000 BPD of crude oil to customers along the Gulf Coast in PADD 3, which covers six states from New

Mexico to Alabama. DSEIS, p. 4.15-72. Because up to 100,000 BPD is reserved for crude oil from Williston Basin and 155,000 BPD to pick-up crude oil from domestic producers delivering to Cushing, Oklahoma, it is estimated that approximately 600,000 BPD of tar sands crudes and up to 830,000 BPD of WCSB crudes will be delivered to PADD 3 refineries for the next decade or two by the Project. DSEIS, p. 4.15-72.

Currently, there are 57 refineries in PADD 3, which have a 2012 capacity to refine 9.2 million BPD of crude. There were 4.62 million BPD of crude oil imported by PADD 3 refineries in 2012, 2.16 million BPD of which was heavy crude, primarily from Venezuela and Mexico with smaller amounts from Columbia, Brazil, Canada and elsewhere. DSEIS, Table 1.4-4. Of these 57 refineries, 15 would be directly connected to hubs connected to the Project. These 15 refineries currently process 4.2 million BPD of crude, of which 1.4 million BPD or 33% is heavy crude. DSEIS, p. 4.15-73. However, heavy crude could be delivered to any of the 57 PADD 3 refineries through other existing pipelines or by tanker, barge, or rail. DSEIS, Table 4.15-18. This significant increase in the processing of WCSB tar sands crudes in PADD 3 refineries will have significant air quality impacts that have been swept under the rug in the DSEIS.

The DSEIS dismisses air quality impacts as insignificant based on four arguments. First, it argues the existing regulatory system would mitigate any impacts. DSEIS, p. 4.15-74. Second, it argues there would be no changes in emissions as the crude quality would not significantly change. DSEIS, p. 4.15-75. Third, the DSEIS argues these imports would not result in any incremental increases in refinery emissions as the crude oil transported by the Project would be replacing or displacing crude oil from other similar sources, e.g., heavy crudes from Mexico and Venezuela. DSEIS, p. 4.15-78. Fourth, and just in case reasons one through three are wrong, the DSEIS presents a range of potential criteria pollutant emissions that might be emitted from refining these imported crudes. The following sections discuss why none of these arguments have any merit. This is followed by a general discussion of the types of impacts that would be expected and the data that would be required (none of which is in the record) to evaluate these impacts.

II. THE EXISTING REGULATORY SYSTEM WOULD NOT MITIGATE AIR QUALITY IMPACTS

First, the DSEIS alleges that the processing of these heavy crudes would occur within existing permits and Consent Decrees. DSEIS, p. 4.15-74. The cumulative air quality impact analysis in the DSEIS rests on the assumption that the air permitting process, never identified specifically, is designed to avoid significant cumulative impacts to regional air quality. DSEIS, p. 4.15-75.

a. AIR PERMITS DO NOT MITIGATE AIR QUALITY IMPACTS OF REFINING WCSB TAR SANDS CRUDES

The claim that existing permits and Consent Decrees would take care of any adverse air quality impact issues is incorrect for several reasons.

First, it is inconsistent with the fact that many of the refineries that would process these crudes (DSEIS, Table 4.15-18) are located in or near areas that currently violate National Ambient Air Quality Standards (NAAQS) in PADD 3. See Exhibit B.

If the existing regulatory system was working, ambient air quality in the vicinity of the affected facilities would at least comply with NAAQS. Thus, the co-location of the subject facilities with areas that currently do not comply with NAAQS is proof that the existing permitting process and Consent Decrees have not prevented significant impacts to regional air quality. The subject refineries are currently causing or contributing to severe air quality impacts. The proposed crude imports will aggravate these impacts by significantly increasing emissions, as explained below.

Second, as discussed in this report, changes in crude quality will result in changes in emissions. Air permitting does not consider the impact of changes in crude quality on emissions.

Third, based on my experience, the air permitting process has proved to be very ineffective in the Gulf Coast states for controlling air pollution. Applicants generally employ a variety of strategies to avoid triggering New Source Review (NSR) permitting in the first place. These strategies include bogus netting analyses; piecemealing of projects (e.g., permitting them a tiny piece at a time as minor amendments to avoid triggering NSR permitting); failure to disclose debottlenecking[1] emission increases which are the *sine qua non* of WCSB tar sands crude upgrades; use of nonrepresentative emission factors to estimate emissions; cherrypicking stack tests to net out of PSD review; and the use of invalid or outdated emission offsets in nonattainment zones. In fact, Texas and Louisiana, the states where most of the subject refining capacity is located, are famous for their permitting shenanigans.

In Texas, for example, most refineries likely to use tar sands crudes have, or have recently had, permits issued under the State's "Flexible Permit" rules.[2] These rules were disapproved by EPA for inclusion in the State Implementation Plan (SIP) and new rules have been proposed, but even these will not cure the implementation problems in Texas.

"Flex" permits, or derivatives thereof, allow major modifications, such as would be required to retrofit a refinery to handle the subject crudes, to avoid NSR/PSD permitting as long as the modification does not exceed plant-wide emission caps. Unlike EPA's approved plantwide applicability limits (PAL) rules, Texas' flexible permit rules allowed refinery-wide emission caps that were calculated from maximum allowable hourly emissions, based on the highest throughputs ever, summed over all units, and then converted to annual averages. These plantwide "flex" permits also voided pre-existing

[1] A bottleneck is a limitation on the operation of an emission unit (e.g., its throughput) due to restrictions at upstream or downstream units that prevents it from reaching its full capacity. The bottleneck thus limits the potential to emit of the bottlenecked unit. Debottlenecking means removing the limitation(s), thus allowing the unit to emit at a higher rate.

[2] See, for example, TNRCC (now TCEQ) Interoffice Memorandum, Flexible Permits and the Plantwide Applicability Limit (PAL), December 31, 1999, Available at: http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/Historical/palmemo.txt.

NSR/PSD limits and substituted the hugely inflated caps, to allow major modifications to occur with no regulatory oversight.

These flex permits with no source-specific limits have allowed major modifications, such as tar sands refinery upgrades, to occur without any offsets in nonattainment areas, BACT (best available control technology) analyses to assure emissions are adequately controlled, meaningful oversight by permitting authorities, netting analysis to determine if NSR permitting would be required, or public notice. The current derivatives of these flex permits raise similar concerns. Thus, recent and pending refinery changes to accommodate these new WCSB tar sands crudes have been treated by Texas as minor modifications or minor amendments to flex permits and have not required any evaluation of air quality impacts.

Further, permits for future projects under currently proposed 2010 rules would pose many of these same problems due to the existence of options such as PALs, permits by rule (allowing de minimus increases from a series of small projects), and minor amendments, among other devices discussed elsewhere in this report to escape any meaningful oversight and emission control.

Finally, permitting does not address cumulative air quality impacts. The Project involves supplying WCSB tar sands crudes to up to 57 separate refineries. Permitting requirements are triggered on a per-refinery basis. Cumulative effects, arising from modifications at several facilities, which individually may be insignificant, but cumulatively significant, would not be addressed even if permitting were triggered and properly executed. Thus, even setting aside the above arguments, permitting alone can never mitigate the cumulative air quality impacts of the Project as they only apply to one refinery at a time. This is particularly true at the PADD 3 refineries in Texas, which are located in or near ozone nonattainment zones, where any increase in NO_x or VOC emissions is *per se* significant.

b. CONSENT DECREES DO NOT MITIGATE AIR QUALITY IMPACTS OF REFINING WCSB TAR SANDS CRUDES

Consent Decrees also provide no assurance that increases in emissions from switching to a heavier dirtier crude will be mitigated.

First, not all refineries in PADD 3 are under Consent Decrees. A recent EPA review identified 10 refineries in PADD 3 that are not covered by Consent Decrees, including the 282,600 BPD Lyondell-Citgo Refinery in Houston, which has direct pipeline connection to the Project. DSEIS, Table 4.15-18.[3] These non-Consent Decree refineries have a combined refining capacity of 724,000 BPD.[4]

[3] This refinery is referred to as "Houston Refining" in the DSEIS (Table 4.15-18), but it is owned by LyondellBasell. See: http://www.lyondellbasell.com/WorldWideLocations/NorthAmerica/USA/Texas/HoustonRefining/.

[4] EPA Enforcement: National Petroleum Refinery Initiative, Draft 2/11/11, Slides, p. 18.

Second, the purpose of Consent Decrees is to bring the subject refineries into compliance with the "marquee" provisions of the Clean Air Act. They are developed to control emissions from refineries in their pre-Consent Decree configurations and to mitigate for existing violations, not to address changes that will be required to refine WCSB tar sands crudes and the resulting increases in emissions. In fact, crude switches are not addressed in Consent Decrees.

Third, the Consent Decrees do not require the best available control technology (BACT) to reduce emissions to the extent feasible nor offsets to assure that increases would not cause or contribute to violations of NAAQS in nonattainment zones. They are settlements, compromises by definition, rather than requirements to mitigate future increases in emissions. Consent Decrees often leave much room for improvement in emission reductions.

For example, a Fluidized Catalytic Cracking Unit or FCCU is required to refine the WCSB tar sands crudes. The FCCU regenerator is typically the main source of emissions at a refinery, contributing about 20% to 30% of the SO_x, 15% to 30% of the NO_x, and 30% to 40% of the PM on a refinery-wide basis. NO_x emissions are ozone precursors and contribute to existing violations of ozone NAAQS. The best control method for NO_x emissions from the FCCU is selective catalytic reduction or SCR, which can remove over 90% of the NO_x. The Consent Decrees for most of the PADD 3 refineries do not require SCRs to control NO_x emissions from the FCCUs, but rather, the much less effective Selective Noncatalytic Reduction (SNCR) method or additives, which remove less than 50% of the NO_x.

Similarly, refining WCSB tar sands crudes will significantly increase emissions from combustion sources, such as heaters and boilers. Refineries typically have many heaters; big refineries may have over a hundred as they supply process heat to nearly every refining process. Refining WCSB tar sands crudes will require large increases in process heat and steam requirements, as discussed elsewhere in this report. The combined emissions from heaters and boilers, especially for NO_x and CO, can be quite large if not adequately controlled.

Emissions from heaters and boilers are typically the major source of emissions from most of the processes that will be most affected by refining WCSB tar sands crudes, e.g., the Crude Unit, Hydrotreaters, Coker. The best available control technology for heaters and boilers for NO_x is SCR and for CO, oxidation catalysts. Very few of the heaters and boilers in PADD 3 refineries use these technologies. The Consent Decrees do not require these technologies at most refineries, but rather less aggressive controls, such as eliminating oil firing, installation of low NO_x burners, and compliance with NSPS Subparts A and J. These types of requirements are not adequate to address the substantial increases in combustion emissions that will result from processing WCSB tar sands crudes in or adjacent to severe ozone nonattainment zones or marginal nonattainment zones.

III. EMISSIONS WOULD INCREASE DUE TO CHANGES IN CRUDE QUALITY

The DSEIS concluded "there would be little, if any, difference in emissions associated with crude oil refining in PADD 3 with or without the proposed Project." DSEIS, p. 4.15-75. This conclusion relies on EnSys modeling in Section 3.13.3 of the FEIS, which concludes that the average API gravity and average sulfur content of the crude oil slate would be essentially the same with or without the proposed Project. DSEIS, p. 4.15-75. This is incorrect as explained below.

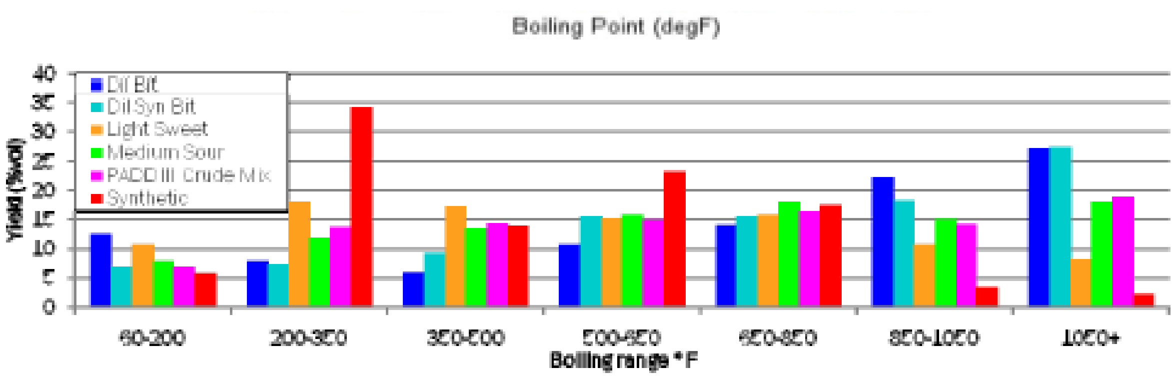
The DSEIS further concludes based on the FEIS that "refinery emissions were not correlated with fluctuations in crude slate quality." DSEIS, p. 4.15-6. This is based solely on a claimed correlation between SO_x emissions and total sulfur in the crude slate (FEIS, p. 3.14-35), which, as described below, is the wrong metric to ferret out changes in emissions due to changes in the crude slate. The underlying data and analysis relied on in the FEIS and DSEIS were not provided. However, one would expect no change in SO_x **emissions** in response to changes in crude total sulfur as most all of the crude sulfur is recovered as elemental sulfur cake in the Sulfur Plant and sold, not emitted. The FEIS did not include the sulfur cake in its analysis. The tiny fraction that is emitted as SO_x originates from sulfur partitioned into the fuel gas and burned in combustion sources. In refineries, this SO_x is typically controlled by permit limits on the amount of sulfur allowed in the fuel gas. Thus, one would expect no correlations between SO_x from combustion sources and crude slate sulfur content. This analysis is irrelevant to the issue at hand.

The DSEIS's claim that there would be little if any difference in emissions associated with refining WCSB tar sands crudes in PADD 3 refineries ignores the fact that there are major chemical differences between conventional and other heavy crudes and WCSB tar sands crude that were not considered in the FEIS or DSEIS.

This is illustrated in Figure 1, which shows the distillation column yields for various WCSB crudes—DilBit (diluted bitumen), DilSynBit (bitumen diluted with traditional diluents and synthetic crude oil), and SCO (synthetic crude oil)—compared to a typical PADD III crude mix and other crudes. The bright pink [ ] is the typical PADD III crude mix, the dark blue [ ] a typical DilBit, the dark geen a typical DilSynBit [ ], and the red [ ] an SCO. This bar chart demonstrates significant differences between the boiling ranges of the WCSB tar sands material and other conventional crudes currently refined in PADD III refineries.[5] These differences in boiling ranges are due to major differences in chemical composition, which directly impact emissions from refining these crudes.

[5] See, for example, Pat Swafford, Evaluating Canadian Crudes in US Gulf Coast Refineries, Crude Oil Quality Association Meeting, February 11, 2010, Available at: http://www.coqa-inc.org/20100211_Swafford_Crude_Evaluations.pdf.

Figure 1: Comparison of Boiling Range (^{o}F) of Typical Gulf Coast Crude Slate with WCSB Tar Sands Crudes



Factors other than API gravity and sulfur content affect refinery emissions, particularly of uncontrolled or otherwise unregulated emissions. These include factors such as the chemical association of sulfur, nitrogen, and other contaminants; the distribution and speciation of organic compounds among the different crude oil fractions;[6] the amount of nitrogen, oxygen, and hydrogen; and trace element composition. See, for example, discussion of diluents elsewhere in this report. This has been totally overlooked in the EIS.

The air quality impacts of refining WCSB tar sands crudes depend on the chemical and physical composition of the refinery slate with WCSB tar sands crude compared to the current slate. There are various ways the WCSB tar sands crude could be integrated into a refinery. It could, for example, replace the current slate completely, as in a refinery built specifically for this purpose. It could replace a similar crude in similar or different amounts. Or it could increase the refining capacity, modifying the current crude slate while remaining within the design basis of the refinery. The DSEIS did not evaluate all of the possibilities, but rather assumed no change in crude slate.

Further, the air quality impacts of switching from current heavy crudes from Mexico and Venezuela to WCSB tar sands crudes depends on the relative composition of the crudes involved in the switch and specifically, the oil fields/formations in Mexico and Venezuela that currently supply the refineries. The EIS does not contain any of the fundamental information required to make this assessment.

The only summary crude composition information is in DSEIS Table 3.13-2. This table excludes most constituents important to estimating emissions (e.g., trace metals, BTEX, nitrogen) and does not include complete composition data for the crudes that it would displace (Mayan and Venezuelan heavy crudes). The type of data required to evaluate emissions would require, at a minimum, the following information for both the current slate, the proposed slate, and the WCSB tar sands crudes that would be substituted or additionally refined. (Note that one cannot eliminate the possibility that

[6] Relative amounts of naphtha, kerosene, diesel, VGO and residue. DilBit crudes, for example, contain large amount of light and heavy cuts and very little mid-range material.

these imported crudes will be used to increase refinery capacity, rather than replacing other crudes in the existing slate.)

- Trace elements (As, B, Cd, Cl, Co, Cr, Cu, Hg, Mn, Mo, Ni, Pb, Sb, Se, U, V, Zn)
- Nitrogen (total & basic)
- Sulfur (total, mercaptans, H_2S)
- Residue properties (saturates, aromatics, resins)
- Acidity
- Aromatics content
- Asphaltenes (pentane, hexane and heptane insolubles)
- Hydrogen content
- Carbon residue (Ramsbottom, Conradson)
- Distillation yields
- Properties by cut
- Hydrocarbon analysis by gas chromatography

None of this information is in the record, preventing any party from performing an analysis of air quality impacts. As none of the basic information required to assess air quality impacts is provided in the record, I will discuss in general some of the impacts that can reasonably be expected from replacing existing crude slates with WCSB tar sands crudes or increasing refinery throughputs with the increase comprised of 100% imported WCSB tar sands crudes. These scenarios are possible as the Project does not contain any restrictions on the end use of the imported crude, i.e., to replace other heavy crudes, to replace existing conventional crudes in current slates, or to increase throughput of the refinery itself.

The DSEIS states that "the Department assumes that the average crude oil flowing through the pipeline would consist of about 50 percent Western Canadian Select (DilBit) and 50 percent Suncor Synthetic A (SCO)." DSEIS, Appx. W, p. 56. DilBit is Canadian tar sands bitumen diluted to pipeline specifications, typically with 25% to 30% diluent. DSEIS, p. 1.4-47, 2-2. Suncor Synthetic A or SCO is a light sweet synthetic crude produced from the Suncor Canada Project located north of Fort McMurray Alberta. However, there are no restrictions on what can be run in the proposed pipeline. In a different section, the DSEIS speculates that KXL will likely move mostly DilBit as well as a variety of SynBits[7] and SCOs. DSEIS, p. 1.4-47, FEIS, p. 3.13-78 ("...the majority of crude oil that would likely be transported by the proposed Project would be DilBit crude oils..."). The temperature effects study in Appendix S of the DSEIS assumes 80% DilBit and 20% SCO. DSEIS, p. S-1 ("The analysis assumes that the pipeline ships 80 percent diluted bitumen and 20 percent synthetic crude.")

[7] SynBit is a combination of bitumen and SCO (synthetic crude oil), typically in an approximately 50-50 ratio. The properties of SynBit blends vary greatly, but blending lighter SCO with heavier bitumen results in a product more similar to conventional crude oil than either SCO or DilBit. FEIS, p. 3.13-30. See also DSEIS, p. 3.13-4 ("SCO may also be used as a diluent for bitumen, in which case the commodity is known as synbit (bitumen diluted with SCO).").

The DSEIS is based on the assumption that the composition of the crude slate will not change and thus will not impact air emissions. However, this is based only on a limited collection of gross or lumper crude quality parameters (DSEIS, Table 3.13-2) and ignores the actual chemical composition of the crudes, which is not disclosed in the DSEIS.

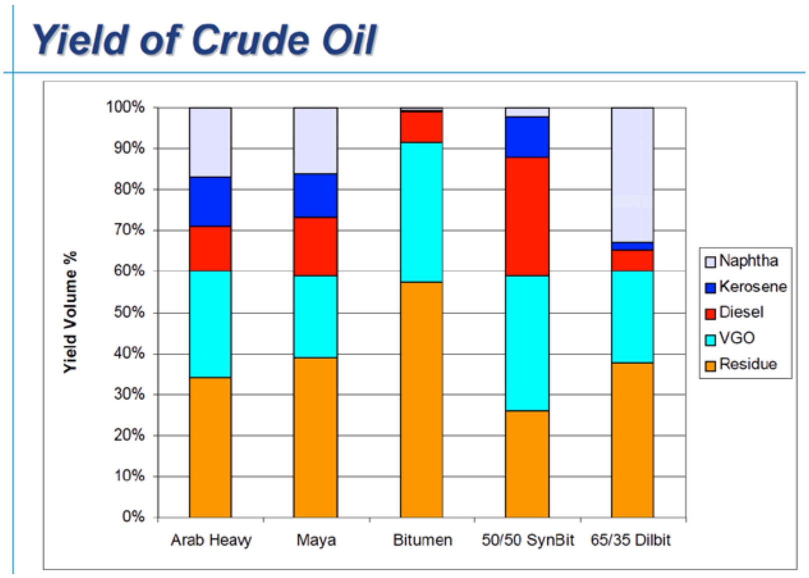
For example, sulfur is not simply sulfur, but is made up of a complex collection of individual chemical compounds such as hydrogen sulfide, mercaptans, thiophene, benzothiophene, methyl sulfonic acid, dimethyl sulfone, thiacyclohexane, etc. Each crude has a different suite of individual sulfur chemicals. The impacts of "sulfur" depend upon the specific sulfur chemicals and their relative concentrations, not on the "gross" amount of total sulfur. The fact that the total sulfur content of the crude slate is the same is irrelevant. This was clearly and tragically demonstrated in the recent (August 2012) catastrophic accident at the Chevron Richmond Refinery in California, caused by the erroneous assumption that sulfur is sulfur. See discussion elsewhere in this report.

The specific chemicals, for example, determine which ones will be volatile and lost through equipment leaks and outgassed from tanks, which ones will be difficult to remove in hydrotreaters and other refining processes (thus determining how much hydrogen and energy must be expended to remove them), and which ones might aggravate corrosion leading to accidental releases. The DSEIS failed to grasp this distinction and looked only to gross chemical characterization data. Thus, it has failed to disclose the impacts of refining WCSB tar sands crudes.

There are two significant differences between the WCSB tar sands crudes that would be transported by the Project and other heavy crudes: (1) the presence of large amounts of diluent[8] and (2) the chemical composition of the heavy ends or residuum, which must be broken down into lighter products, usually in a coker. This is illustrated in Figure 2, which is a bar chart of the output of the distillation column for two commonly refined conventional heavy crudes—Arab Heavy and Maya—and three WCSB crudes—raw bitumen, SynBit, and DilBit.

[8] The DSEIS is silent on whether the Mexican and Venezuelan heavy crudes the WCSB crudes could replace are also mixed with diluent.

Figure 2: Oil Distributions of Conventional and Canadian DilBit and SynBit[9]



The majority of the WCSB crudes that will be transported by the Project are DilBits, the last bar in Figure 2. These DilBits are sometimes referred to as "dumbell" or "barbell" crudes as the majority of the diluent is C_5 to C_{12} and the majority of the bitumen is C_{30}+ boiling range material, with very little in between.[10] This means these crudes have a lot of material boiling at each end of the boiling point curve, but little in the middle. Thus, they yield very little middle distillate fuels, such as diesel, heating oil, kerosene, and jet fuel and more coke, than other heavy crudes. A typical DilBit, for example, will have 15% to 20% by weight light material, basically the added diluent, 10% to 15% middle distillate, and the balance, >75% is heavy residual material (vacuum gas oil and residue) exiting the distillation column. These characteristics, which distinguish DilBits from the typical PADD 3 crude slate and conventional heavy crudes refined in PADD 3, have two major implications for emissions from refineries.

First, the large amount of light material that distills below 149 C is very volatile and can be emitted to the atmosphere from storage tanks and equipment leaks of fugitive components (pumps, compressors, valves, fittings) in much larger amounts than other heavy crudes that it would replace. The DSEIS does not indicate whether other heavy crudes processed in PADD 3 refineries currently arrive with diluent. However, as the heavy crudes from Venezuela and Mexico typically arrive at the Gulf Coast via tankers – as opposed to via pipeline – they do not need to be transported with diluents. Thus, the use of diluent to transport WCSB tar sands crudes is likely an important difference between the current heavy crude slates processed in PADD 3 refineries and the proposed

[9] Kevin Turini and others, Processing Heavy Crudes in Existing Refineries, Slides, 2011 AIChe Meeting, Chicago, IL.
[10] Gary R. Brierley and others, Changing Refinery Configuration for Heavy and Synthetic Crude Processing, 2006, Available at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BA07DE342-E9B1-402A-83F7-36B18DC3DD05%7D&documentTitle=5639138.

WCSB tar sands crudes that would replace them. This diluent will have impacts along the entire length of the pipeline as well as at all units within refineries that process it.

Second, the large amount of heavy material in the bitumen fraction means that existing equipment will have to work harder to convert it into desirable byproducts. This translates into more emissions from heaters, boilers, cokers, the hydrogen plant, and fluid catalytic crackers, among others. It also means much more highly contaminated coke will be produced and much more electricity will be used.

a. DILUENT WOULD INCREASE EMISSIONS

Most of the WCSB tar sands crudes are too heavy to flow in a pipeline. Thus, they must be diluted or thinned with a lighter hydrocarbon stream to reduce viscosity and density to meet pipeline specifications. More diluent is required in the winter than summer to maintain flow rates during cold weather. DilBit is a mixture of bitumen, the raw heavy oil, mixed with about 25% to 30% diluent, which is typically natural gas condensate, pentanes, or naphtha.[11] The DSEIS is silent on the composition and emissions from this diluent. These are significant omissions as the emissions from handling this material are large and significant.

The analyses in the DSEIS appear to assume that diluent mixed with bitumens and transported by pipeline would be processed with the bitumen at the receiving refineries. DSEIS, pp. 4.15-83, notes to Fig. 4.15.3-3; 4.15-84, notes to Fig. 4.15.3-4. Elsewhere, the DSEIS asserts that "once diluent and bitumen are mixed together to form dilbit, they behave as a conventional crude oil." See also DSEIS, Appx. W, p. 26 ("The estimates where diluent is refined with the raw bitumen at the refinery are representative of the proposed Project, since diluent will not be recirculated by the pipeline.") Therefore, the analysis in the DSEIS appears to treat the DilBit as a single substance. DSEIS, p. 4.13-17, 4.13-45.

However, one cannot eliminate the possibility that the diluent would be separated from the DilBit and returned to Canada or elsewhere at some point in the future. See DSEIS, p. 1.4-47. There is nothing in the DSEIS that requires diluent to be processed with the bitumen and not separated and sent elsewhere for processing. It is possible that at some point over the operation of the facility that it would be more economical to return the diluent to Canada or elsewhere rather than to refine it at U.S. refineries.
The DSEIS places no restrictions on the handling of diluent. Regardless of the actual disposition of the diluent, the EIS must consider impacts from processing bitumen blended with 20% to 30% diluent, a very large amount of light material compared to other heavy crudes currently processed in PADD 3 refineries. This will increase emissions of volatile organic compounds (VOCs), Hazardous Air Pollutants (HAPs) and other pollutants compared to current heavy crudes. Thus, the air quality impacts of both

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[11] Gary R. Brierley, Visnja A. Gembicki, and Tim M. Cowan, Changing Refinery Configurations for Heavy and Synthetic Crude Processing, Available at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BA07DE342-E9B1-402A-83F7-36B18DC3DD05%7D&documentTitle=5639138.

options, separation and return to Canada or elsewhere, and processing at the local refinery, should have been evaluated. Neither was.

The mixture of diluent and bitumen does not behave the same as a conventional crude, as the distribution of hydrocarbons is very different. The blended lighter diluent generally evaporates readily when exposed to ambient conditions, leaving behind the heavy ends, the vacuum gas oil (VGO) and residuum.[12] Thus, when a DilBit is released accidentally, it will generally create a difficult to cleanup spill as the heavier bitumen will be left behind.[13] Further, in a storage tank, the diluent also is rapidly evaporated.

In the refinery, diluent distills in the atmospheric column in the Crude Unit, leaving the very heavy 6-8^{o} API feed to the vacuum unit, which requires more energy to process, thus releasing more emissions. This does not occur with other heavy crudes currently run in PADD 3 refineries. Thus, this affects all downstream refining operations and leads to conditions that increase emissions, e.g., heater coking, increased heater firing.[14]

The separated diluent would be hydrotreated in the Naptha Hydrotreater. This unit removes impurities in the naphtha, primarily sulfur as hydrogen sulfide (H_2S) by reacting hydrogen and naphtha in vapor phase over a fixed catalyst bed. Some of the hydrotreated material would be further upgraded, as required, and outputs blended into gasoline. The increased amounts of naphtha, compared to conventional heavy crudes, would require increased amounts of hydrogen and increased fuel consumption to generate heat. Further, in some cases, all of the light naphtha originating from the diluent may not be able to be blended into the gasoline pool without exceeding vapor pressure specifications. This would require shipping the recovered diluent elsewhere,[15] increasing VOC emissions.

The diluent is a low molecular weight organic material with a high vapor pressure that contains high levels of VOCs, sulfur compounds, and HAPs. These may all be emitted from storage tanks and leaks from many thousands of pumps, compressors, valves, and flanges in the system used to store and transport DilBits. The composition of some typical diluents/condensates is reported on the website, www.crudemonitor.ca.[16] The specific diluents that would be used by the Project are unknown.

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[12] The residuum is the residue obtained from the oil after nondestructive distillation has removed all of the volatile materials. Residua are black, viscous materials. They may be liquid at room temperature (from the atmospheric distillation tower) or almost solid (generally vacuum residua), depending upon the nature of the crude oil.

[13] A Dilbit Primer: How It's Different from Conventional Oil, Inside Climate News. Available at: http://insideclimatenews.org/news/20120626/dilbit-primer-diluted-bitumen-conventional-oil-tar-sands-Alberta-Kalamazoo-Keystone-XL-Enbridge?page=show.

[14] Steve White and Tony Barietta, Refiners Processing Heavy Crudes can Experience Crude Distillation Problems, Oil&Gas Journal, November 18, 2002.

[15] Brierley et al. 2006, p. 9.

[16] Condensate Blend (CRW) - http://www.crudemonitor.ca/condensate.php?acr=CRW; Fort Saskatchewan Condensate (CFT) - http://www.crudemonitor.ca/condensate.php?acr=CFT; Peace Condensate (CPR) - http://www.crudemonitor.ca/condensate.php?acr=CPR; Pembina Condensate (CPM) - http://www.crudemonitor.ca/condensate.php?acr=CPM; Rangeland Condensate (CRL) -

The CrudeMonitor information indicates that diluent contains very high concentrations (based on 5-year averages) of the hazardous air pollutants (HAPS) benzene (5,200 ppm to 9,800 ppm); toluene (10,300 ppm to 25,300 ppm); ethyl benzene (900 ppm to 2,900 ppm); and xylenes (4,600 ppm to 23,900 ppm).

The sum of these four compounds is known as "BTEX" or benzene-toluene-ethylbenzene-xylene. The BTEX in diluent ranges from 27,000 ppm to 60,900 ppm. The BTEX in DilBits, blended from these materials, ranges from 8,000 ppm, to 12,400 ppm.[17] Similarly, the BTEX in SCOs ranges from 6,100 ppm to 14,100 ppm.[18]

The FEIS conceded that DilBits would be delivered by the Project with a "slightly higher BTEX content than many other heavy crude oils, but a lower BTEX content than Mexican Maya...". However, an examination of the FEIS's supporting data in Table 3.14.3-6 indicates that even based on its own data, this is incorrect. Table 3.14.3-6 reports Mexican Maya crudes contain 5,500 to 9,773 ppm BTEX, while the single DilBit is reported at 9,800 ppm and SynCrude Synthetic at 13,100 ppm, above the upper end of the range of Mexican Maya. The more comprehensive collection of DilBit data reported on CrudeMonitor indicates a BTEX range of 8,000 ppm to 12,400 ppm, or much higher than Mexican Maya, or any other heavy crude. FEIS, Table 3.14.3-6. Thus, WCSB tar sands crudes will increase BTEX emissions from equipment leaks from compressors, pumps, valves, flanges, and tanks. These are hazardous air pollutants with public health implications for neighbors of the refineries.

The CrudeMontior information also indicates that these diluents contain elevated concentrations of volatile mercaptans (9.9 to 103.5 ppm), which are highly odiferous and toxic compounds that will create odor and nuisance problems along the pipeline and

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http://www.crudemonitor.ca/condensate.php?acr=CRL; Southern Lights Diluent (SLD) - http://www.crudemonitor.ca/condensate.php?acr=SLD.

[17] DilBits: Access Western Blend (AWB) -http://www.crudemonitor.ca/crude.php?acr=AWB; Borealis Heavy Blend (BHB) -http://www.crudemonitor.ca/crude.php?acr=BHB; Christina Dilbit Blend (CDB) - http://www.crudemonitor.ca/crude.php?acr=CBD; Cold Lake (CL) - http://www.crudemonitor.ca/crude.php?acr=CL; Peace River Heavy (PH) - http://www.crudemonitor.ca/crude.php?acr=PH; Seal Heavy (SH) - http://www.crudemonitor.ca/crude.php?acr=SH; Statoil Cheecham Blend (SCB) - http://www.crudemonitor.ca/crude.php?acr=SCB; Wabasca Heavy (WH) - http://www.crudemonitor.ca/crude.php?acr=WH; Western Canadian Select (WCS) - http://www.crudemonitor.ca/crude.php?acr=WCS; Albian Heavy Synthetic (AHS) (DilSynBit) - http://www.crudemonitor.ca/crude.php?acr=AHS.

[18] SCOs: CNRL Light Sweet Synthetic (CNS) -http://www.crudemonitor.ca/crude.php?acr=CNS; Husky Synthetic Blend (HSB) -http://www.crudemonitor.ca/crude.php?acr=HSB; Long Lake Light Synthetic (PSC) -http://www.crudemonitor.ca/crude.php?acr=PSC; Premium Albian Synthetic (PAS) - http://www.crudemonitor.ca/crude.php?acr=PAS; Shell Synthetic Light (SSX) - http://www.crudemonitor.ca/crude.php?acr=SSX; Suncor Synthetic A (OSA) - http://www.crudemonitor.ca/crude.php?acr=OSA; Syncrude Synthetic (SYN) - http://www.crudemonitor.ca/crude.php?acr=SYN.

around refineries where it is processed. Mercaptans can be detected at concentrations over a million times lower than will be present in emissions from the pipeline and its appurtenances.[19] In fact, mercaptans are added to natural gas in very tiny amounts so that the gas can be smelled to facilitate detecting leaks.

Thus, unloading, storing, handling and refining of bitumens mixed with diluent would emit VOCs, HAPs, and sulfur compounds, depending upon the DilBit source. There are no restrictions on the diluent source or composition nor any requirements to monitor emissions from tanks and leaking equipment where DilBit is handled. As the market has experienced shortages of diluents, any material with a suitable thinning ability could be used, which could contain currently unanticipated hazardous components.

Diluent would be present in the crude stored in crude storage tanks and would be present in component leaks from its entry into the refinery until it is recovered and marketed, or at least between the desalter and downstream units where some of it is recovered. The presence of diluent would increase the vapor pressure of the crude, substantially increasing VOC and HAPs emissions from tanks and fugitive component leaks compared to those from displaced heavy crudes not blended with diluent. The diluent byproduct removed during refining also will be stored in tanks for blending into gasoline or other products. These tanks also will emit VOCs and HAPs. The affected sources would include new tanks, existing tanks, new fugitive components, and existing fugitive components that would handle the diluent product, as well diluent-affected byproducts.

The FEIS and DSEIS made no attempt to estimate these emissions. The emissions from the Motiva and Hyperion projects, relied on to estimate a range of VOC emissions from the Project, do not include the contribution of VOCs from diluent as they are based on conventional fugitive and tank emission factors, developed for other materials.[20] In fact, these conventional emission factors have been demonstrated to underestimate emissions from even the conventional sources they purport to represent by significant amounts in PADD 3 refineries most likely to accept the imported WCSB tar sands crudes.

The increase in VOC and HAP emissions from handling diluent would not be discovered by monitoring or addressed by permitting, as these emissions are typically calculated using standard emission factors that do not consider the presence of diluent. Measurements are not made to confirm fugitive emissions. In the areas with the highest concentration of refineries likely to process these WCSB tar sands crudes, studies have demonstrated that existing methods of estimating emissions from the types of sources that

[19] American Industrial Hygiene Association, Odor Thresholds for Chemicals with Established Occupational Health Standards, 1989; American Petroleum Institute, Manual on Disposal of Refinery Wastes, Volume on Atmospheric Emissions, Chapter 16 - Odors, May 1976, Table 16-1.

[20] See, e.g., EPA, Protocol for Equipment Leak Emission Estimates, November 1995. This report is the basis for the emission factors used to estimate VOC emissions from fugitive components in refineries. It does not consider the increase in emissions due to elevated vapor pressure of diluent blended materials as they were unknown at the time of this work. These factors, or derivatives thereof, are used throughout PADD 3. They have not been updated since this report was published.

would emit diluent grossly underestimate emissions. And these underestimates occur in areas where the air quality already exceeds acceptable levels. Thus, any increases in VOC and HAP emissions from handling diluent-blended materials by the Project, which would not be detected by any existing regulatory program, must be prevented.

It is well known based on measurement studies that VOC emissions from equipment leaks of conventional petroleum products are underestimated by factors of 3 to 20.[21] The U.K.'s National Physical Laboratory (equivalent to the U.S. National Institute of Standards and Technology) has compared direct measurements of fugitive VOCs with those estimated by emission factors for over a decade and found the direct measurements were about three times higher on a plant-wide basis than calculated using emission factors relied on in the Project.[22] In support, U.S. EPA auditors have found far more leaks than reported by the facility's program, indicating higher routine emissions than belied by the data.[23]

Recent studies confirm the approach used to estimate fugitive VOC emissions from the Motiva and Hyperion projects relied on in the DSEIS to estimate emissions (and others not cited) result in significant underestimates in VOC emissions. Monitoring and modeling studies in Texas, where most of the imported tar sands crudes will be refined, have demonstrated "severe inconsistencies" between reported and measured emissions. One study concluded: "We believe that our results show that the inventory of industrial VOC emissions [prepared using TCEQ calculation methods such as those used in the Motiva and Hyperion applications] is inaccurate in its location, composition, and emission rates of major sources… Most of the emissions are so-called fugitive emissions from leaking valves, pipes, or connectors, of which there are tens of thousands in a large facility."[24]

[21] Allan K. Chambers, et al., Direct Measurement of Fugitive Hydrocarbons from a Refinery, *J. Air & Waste Mgmt. Ass'n*, 58:1047-1056 (2008), at 1054 and Table 7; Clearstone Engineering Ltd., September 6, 2006; M. Kihlman, et al., *Monitoring of VOC Emissions from Refineries in Sweden Using the SOF Method*, http://www.fluxsense.se/reports/paper%202%20final%20lic.pdf; IMPEL, Diffuse VOC Emissions, December 2000, at p. 38; U.S. Environmental Protection Agency, Office of Inspector General, EPA Can Improve Emissions Factors Development and Management, Evaluation Report, Report No. 2006-P-00017 (March 22, 2006), pp. 11-12 (summarizing the Texas 2000 Air Quality Study… "This primarily involved under reporting of emissions from flares, process vents, and cooling towers, as well as from fugitive emissions (leaks). The under-reporting was caused largely due to the use of poor quality emissions factors."); U.S. Environmental Protection Agency, VOC Fugitive Losses: New Monitors, Emissions Losses, and Potential Policy Gaps, 2006 International Workshop (October 25-27, 2006), ("VOC Fugitive Losses") p. vii and p. 1 ("emissions from refinery and natural gas operations may be 10 to 20 times greater than the amount estimated using standard emission factors."); *Id*., p. 3 ("Typically, measurements did show some 10 to 20 times higher emissions than calculated at initial measurement activities…Today, after long term experience with the measurements and also after successful improvements of plant operations regarding emissions, emission levels of some 3 to 10 times higher than what is theoretically calculated are typically seen.")

[22] VOC Fugitive Losses at. 23. *See* also results of Swedish studies in this same report at p. 213.

[23] *See* U.S. EPA's recent refinery settlements at http://www.epa.gov/compliance/resources/cases/civil/caa/oil/index.html.

[24] Ronald C. Henry and others, Reported Emissions of Organic Gases are not Consistent with Observation, Proc. Natl. Acad. Sci., v. 94, June 1997, pp. 6596-6599; available at: http://www.pnas.org/content/94/13/6596.full.pdf.

This conclusion has been confirmed in numerous studies in the past decade, *viz*., "The analysis presented here for 2000, 2002, and 2006 measurements in the Houston-Galveston-Brazoria area indicates that emission inventory inaccuracies persist."[25] "We conclude that consistently large discrepancies between measurement-derived and tabulated (alkene/NO_x) ratios are due to consistently and substantially underestimated VOC emissions from the petrochemical facilities."[26] "The results… show that the emissions of ethene and propene, obtained by SOF [solar occultation flux], are on average an order of magnitude larger than what is reported in the 2006 daily EI [Emission Inventory]."[27]

A 2006 study reported: "… we do not find good agreement between the measured plume composition and the VOC speciation in the emissions inventory. These observations are not surprising, as previous research has shown that emission fluxes of individual VOCs may be underestimated by as much as 1-2 orders of magnitude in inventories for the Houston area… The frequent lack of correlation between large VOC enhancements and enhancements in SO_x, NO_x and CO suggests large, non-combustion sources of VOCs" [28] [*e.g.*, fugitive equipment leaks]. One study, for example, reported that measurements of ethene from petrochemical facilities were one to two orders of magnitude higher than reported in the emission inventory.[29] Monitoring data collected during the 2006 Texas Air Quality Study demonstrated that "[i]ndustrial ethylene and propylene emissions in the NEI05-REF are greatly underestimated relative to the estimates using SOF measurements in the Houston Ship Channel during the study period."[30]

[25] R.A. Washenfelder and others, Characterization of NO_x, SO_2, Ethene, and Propene from Industrial Emission Sources in Houston, Texas, J. Geophys. Res., v. 115, D16311, 2010; J.A. de Gouw and others, Airborne Measurements of Ethene from Industrial Sources using Laser Photo-Acoustic Spectroscopy, Environ. Sci. Technol., v. 43, no. 7, 2009, pp. 2437-2442; B.T. Jobson and others, Hydrocarbon Source Signatures in Houston, Texas: Influence of the Petrochemical Industry, J. Geophys. Res., v. 109, 2004; T. Karl and others, Use of Proton-transfer-reaction Mass Spectrometry to Characterize Volatile Organic Compound Sources at the La Porte Super Site during the Texas Air Quality Study 2000, J. Geophys. Res., v. 108(D16), 2003; L.I. Kleinman and others, Ozone Production Rate and Hydrocarbon Reactivity in 5 Urban Areas: A Cause of High Ozone Concentration in Houston, Geophys. Res. Lett., v. 29, no. 10, 2002; J. Mellqvist and others, Measurements of Industrial Emissions of Alkenes in Texas using the Solar Occultation Flux Method, J. Geophys. Res., v. 115, 2010; T.B. Ryerson and others, Effect of Petrochemical Industrial Emissions of Reactive Alkenes and NO_x on Tropospheric Ozone Formation in Houston, Texas, J. Geophys. Res., v. 108(D8), 2003; B.P. Wert, Signatures of Terminal Alkene Oxidation in Airborne Formaldehyde Measurements during TexAQS 2000, J. Geophys. Res., v. 108(D3), 2003.

[26] T.B. Ryerson and others.

[27] J. Mellqvist and others.

[28] Daniel Bon and others, Evaluation of the Industrial Point Source Emission Inventory for the Houston Ship Channel Area Using Ship-Based, High Time Resolution Measurements of Volatile Organic Compounds, CIRES; available at: http://cires.colorado.edu/events/rendezvous/posters/detail.php?id=3866.

[29] E.B. Cowling and others, A Report to the Texas Commission on Environmental Quality by the TexAQSII Rapid Science Synthesis Team, Prepared by the Southern oxidants Study Office of the Director at North Carolina State University, August 31, 2007, available at: http://aqrp.ceer.utexas.edu/docs/RSSTFinalReportAug31.pdf.

[30] S.-W. Kim and others, Evaluations of NO_x and Highly Reactive VOC Emission Inventories in Texas and the Implications for Ozone Plume Simulations during the Texas Air Quality Study 2006, Atmos. Chem.

These and other studies have consistently shown based on actual monitoring that emissions estimated using TCEQ fugitive equipment leak emission factors have underestimated VOC emissions by significant amounts. The ability of current permitting procedures to mitigate air quality impacts from WCSB tar sands crudes is limited by the use of these long discredited emission factors.

The DSEIS should be revised to describe the handling of diluent-blended materials and any separated diluent. HAP and VOC emissions from these sources—tanks and fugitive equipment leaks—should be estimated using accurate emission factors that account for the type and amount of diluent that will be presented in WCSB tar sands crudes.

This is very important because VOCs are converted into ozone in the atmosphere and thus are ozone precursors. The VOC emissions from diluent are particularly important as they can cause or contribute to violations of ozone NAAQS. Most of the refineries that would be directly connected to the proposed pipeline are located within or near ozone nonattainment zones. An ozone nonattainment zone is an area where the ambient air quality currently exceeds NAAQS and thus is unhealthy to breath.

Exhibit B shows that eight out of the 15 refineries with direct pipeline access to the proposed Project (DSEIS, Table 4.15-18), responsible for refining 2.7 million barrels of crude or 60% of the refinery capacity with direct access to the Project, are located in **severe** nonattainment zones for the 1997 8-hour ozone standard and marginal nonattainment zones for the 2008 8-hour ozone standard. Two other refineries in Louisiana are also in marginal nonattainment zones for the 2008 8-hour ozone NAAQS. This means VOC emissions from handling DilBit crudes will cause or contribute to existing violations of ozone NAAQS, which is a per se significant air quality impact not disclosed in the DSEIS. The DSEIS did not even disclose that some of the refineries that would process the imported crudes would be located in or near ozone nonattainment zones. The DSEIS should be revised to include ozone modeling for all refineries in PADD 3 that will receive diluent-blended WCSB tar sands crudes.

Thus, in sum, the Project will increase the emission of VOC from the transport, handling, and processing of bitumens blended with high vapor pressure diluents. These increases will not be mitigated during the routine process of permitting or post-construction monitoring because the emission estimation procedure does not include the contribution of diluent, the emission factor approach used to estimate the emissions is known to grossly underestimate them, and post-construction monitoring will not be used, so VOC increases will never be detected and controlled.

Phys. Discuss, v. 11, 2011, pp. 21,201 - 21,265, available at: http://www.atmos-chem-phys-discuss.net/11/21201/2011/acpd-11-21201-2011.pdf.

b. OTHER COMPONENTS OF WCSB TAR SANDS CRUDES WOULD INCREASE EMISSIONS COMPARED TO CONVENTIONAL HEAVY CRUDES

The composition of WCSB tar sands crudes are chemically different from other heavy crudes currently processed in PADD 3 refineries. They are unique for two major reasons: (1) presence of large quantities of volatile diluent full of VOCs and toxic chemicals and (2) unique chemical composition of the heavy ends or residuum. The previous section discussed diluent. The composition of the heavy ends, which have higher molecular weight chemicals and are deficient in hydrogen, means more energy will be required to convert them into the same slate of refined products. Thus, most fired sources in the refinery—flares, heaters, boilers, etc.—will have to work harder to generate the same quality of refined products. This section discusses the heavy ends and their impact on refining emissions.

The DSEIS makes a number of critical assumptions that determine the outcome of the analysis. If these assumptions are not required as conditions of Project approval, and they are not, the applicant will have the discretion to implement the Project unfettered. First, the air quality impacts assume that "oil that would be transported by the proposed Project (830,000 BPD) would replace historic crude oil supplies or supplant supplies from less stable or more costly sources." DSEIS, p. 4.15-77.

Many other options are possible, including: (1) increased refining capacity up to 830,000 BPD, of which 100% would be WCSB crude, either 100% DilBit or 100% SCO or some combination thereof is possible; (2) replacing current light oil blend stocks with WCSB tar sands crude without increasing total refining capacity. The Motiva upgrade relied on in the DSEIS to estimate emissions is actually a brand new 315,000 BPD refinery, capable to processing 38% of the WCSB crude input from the Project, without blending it with any other feedstock to meet a current crude slate. The composition of the oil was not even addressed in the Motiva Application.

Further, the DSEIS argues the crude slate would remain the same, based solely on API gravity and average sulfur content, two lumper parameters with little relevance for refinery emissions. DSEIS, p. 4.15-75. However, this ignores the fact that the factors that affect emissions are much more complex than belied by these lumper parameters. As noted previously, sulfur is not sulfur. Nor does API gravity tell you anything about emissions or corrosion that may lead to accidental releases. Many different chemicals can add up to the same API crude gravity, resulting in major differences in processing requirements and thus emissions.

The DSEIS argues that the physical and chemical properties of the crude oils that would be transported by the proposed pipeline would not be unique to the proposed Project. It goes on to state that: "A comparison of the crude oil that would be transported by the proposed pipeline with other conventional crude oils indicates that the characteristics of the proposed Project's crude oil are generally comparable to those of conventional crude oils..." DSEIS, p. 3.13-1. It then presents tables summarizing chemical characterization data for various crudes. DSEIS, Tables 3.13-1, 3.13-2.

However, the summarized data is mostly gross physical and chemical characterization data. It does not include the type of information required to determine the impact of these crudes on air emissions from crude transport, storage, and refining.

The chemical composition of the WCSB tar sands crude is different in important ways from current refinery slates[31] and will increase emissions far beyond those disclosed in the DSEIS. The U.S. Geological Survey ("USGS"), for example, reported that "natural bitumen," the source of all Canadian tar sands-derived oils, contains 102 times more copper, 21 times more vanadium, 11 times more sulfur, six times more nitrogen, 11 times more nickel, and 5 times more lead than conventional heavy crude oil.[32]

The environmental damage caused by these pollutants includes acid rain; bioaccumulation of toxic chemicals up the food chain; the formation of ground-level ozone and smog; visibility impairment in Class I areas, such as National Parks; odor impacts that affect residents along both the pipeline and downstream processing facilities; and depletion of soil nutrients.

Refining converts crude oils into transportation fuels. This is done by removing contaminants (sulfur, nitrogen, metals) and breaking down and reassembling chemicals present in the crude oil charge by adding hydrogen, removing carbon as coke, and applying heat, pressure, and steam in the presence of various catalysts. More intensive refining is required to convert WCSB tar sands crudes into useful products than other heavy crudes. This means a greater amount of energy must be expended to yield the same product slate. Thus, all of the combustion sources in a refinery, such as heaters and boilers, must work harder and thus emit more pollutants, than when refining conventional crudes. The DSEIS fails to adequately analyze the impact of crude composition on emissions.

Most refineries in PADD 3, even those that currently process heavy crudes, will have to be upgraded to handle WCSB tar sands crudes. The very fact that these refineries must be upgraded to handle these crudes is prima facie evidence that the WCSB tar sands crudes are unique and distinguishable from the heavy crude slates currently refined.

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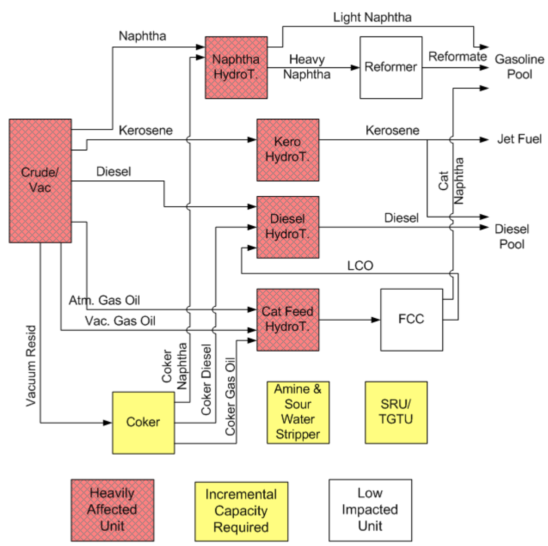
[31] Brian Hitchon and R.H. Filby, Geochemical Studies - 1 Trace Elements in Alberta Crude Oils, http://www.ags.gov.ab.ca/publications/OFR/PDF/OFR_1983_02.PDF;
F.S. Jacobs and R.H. Filby, Trace Element Composition of Athabasca Tar Sands and Extracted Bitumens, Atomic and Nuclear Methods in Fossil Energy Research, 1982, pp 49-59; James G. Speight, The Desulfurization of Heavy Oils and Residua, Marcel Dekker, Inc., 1981, Tables 1-1, 2-2, 2-3, 2-4 and p. 13 and James G. Speight, Synthetic Fuels Handbook: Properties, Process, and Performance, McGraw-Hill, 2008, Tables A.2, A.3, and A.4; Pat Swafford, Evaluating Canadian Crudes in US Gulf Coast Refineries, Crude Oil Quality Association Meeting, February 11, 2010, Available at: http://www.coqa-inc.org/20100211_Swafford_Crude_Evaluations.pdf.
[32] R.F. Meyer, E.D. Attanasi, and P.A. Freeman, Heavy Oil and Natural Bitumen Resources in Geological Basins of the World, U.S. Geological Survey Open-File Report 2007-1084, 2007, p. 14, Table 1, Available at http://pubs.usgs.gov/of/2007/1084/OF2007-1084v1.pdf.

Some PADD 3 refineries have already been upgraded in anticipation of Keystone XL (FEIS, p. 3.14-30),[33] but most still require upgrades. The upgrades will increase emissions of criteria and HAP pollutants. Many of the required modifications will not be subject to permit restrictions, such as increased flaring, increased firing rates and throughputs that fall within Flex permit caps, debottlenecked emission units that escape identification, and accidental releases due to corrosion that results in equipment failures.

Further, while some individual changes may not by themselves be large enough to trigger any regulatory reviews, the cumulative air quality impacts from many facilities increasing emissions simultaneously will not be considered by any existing regulatory framework except the NEPA review process. Thus, it is very important to identify and quantify the potential increase in emission of all pollutants, not just GHG. Finally, most of the modified facilities are within or near severe ozone nonattainment areas where any increase in NO_x or VOC emissions is per se significant.

The red units in Figure 3 are the refining processes most likely to require major upgrades and/or new units, the yellow units are those that are fairly likely to require upgrades, and others will require minor changes. However, emissions from every unit in a refinery will be impacted in some way.

Figure 3: Simplified Refinery Flow Diagram Showing Units Most Impacted by Switching to WCSB Tar Sands Crudes



[33] See also: Motiva (DEIS, p. 4.15-76); Total Refinery, Port Arthur, See: http://www.hydrocarbonprocessing.com/Article/2819752/Total-completes-deep-conversion-at-Port-Arthur-refinery-new-units-on-stream.html); Valero Refinery in Port Arthur (listed in some places as Premcor Refining Group, which was acquired by Valero in 2005), recently expanded its coker by 10,000 BPD and its crude and vacuum units. See: http://www.valero.com/ourbusiness/ourlocations/refineries/pages/portarthur.aspx) and http://www.reuters.com/article/2012/07/31/refinery-operations-valero-idUSL2E8IV3LA20120731.

Canadian tar sands bitumen, the predominant source of WCSB crude, is distinguished from conventional petroleum by the small concentration of low molecular weight hydrocarbons and the abundance of high molecular weight polymeric material.[34] Crudes derived from Canadian tar sands bitumen—DilBits, SCOs and SynBits—are heavier, i.e., have larger, more complex molecules such as asphaltenes,[35] some with molecular weights above 15,000.[36] They generally have higher amounts of coke-forming precursors; larger amounts of contaminants (sulfur, nitrogen nickel, vanadium) and are deficient in hydrogen, compared to other heavy crudes. Thus, to convert them into the same refined products requires more energy, electricity, water, and hydrogen. This requires that more fuel be burned in most every fired source at the refinery and that more water be circulated in heat exchangers and cooling towers. Further, this requires more fuel to be burned in any supporting off-site facilities, such as power plants that may supply electricity or Steam-Methane Reforming Plants that may supply hydrogen. These increases in fuel consumption release increased amounts of NO_x, SO_x, VOCs, CO, PM10, PM2.5, and HAPs as well as greenhouse gas emissions. Some of the required refinery changes and their emission consequences are discussed below.

The DSEIS contains no information to estimate the magnitude of these types of increases nor does it even acknowledge that such increases would occur. In Texas, these types of increases would be glossed over in the Flex permitting system as they would occur within existing inflated plant-wide emission caps. Further, conventional refinery permitting does not consider the effect of crude composition on emissions. Air permits do not restrict refineries to a specific crude or crude composition. Thus, significant increases in emissions can occur that would not be subject to any controls and that would not be detected in areas with severely degraded air quality.

i. Crude Unit

The first step in the refining process is to separate the crude oil into fractions based on boiling point by distillation. This occurs in the crude unit where the crude is first heated in a furnace and charged to an atmospheric distillation tower, where it is separated into products: naphtha, kerosene, diesel, and residuum. The tower bottoms or residuum, which occurs in greater amounts in the WCSB tar sands crudes that would be transported by the Project than other heavy crudes, is sent to another furnace for more heating and charged to a vacuum tower to separate out heavier material into gas oil, lubricating oils, and vacuum residuum. The higher the density of the crude, the more heat required to prepare the crude for distillation. More heat means burning more fuel, which releases more NO_x, SO_x, CO, VOCs, PM10, and PM2.5.

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[34] O.P. Strausz, The Chemistry of the Alberta Oil Sand Bitumen, Available at: http://web.anl.gov/PCS/acsfuel/preprint%20archive/Files/22_3_MONTREAL_06-77_0171.pdf.
[35] Asphaltenes are nonvolatile fractions of petroleum that contain the highest proportions of heteroatoms, i.e., sulfur, nitrogen, oxygen. The asphaltene fraction is that portion of material that is precipitated when a large excess of a low-boiling liquid hydrocarbon such as pentane is added. They are dark brown to black amorphous solids that do not melt prior to decomposition and are soluble in benzene and aromatic naphthas.
[36] O.P. Strausz, The Chemistry of the Alberta Oil Sand Bitumen, Available at: http://web.anl.gov/PCS/acsfuel/preprint%20archive/Files/22_3_MONTREAL_06-77_0171.pdf.

ii. Hydrotreating

The various crude fractions from the crude distillation unit and coker (naphtha, diesel, gas oil) must be cleaned up to meet product specifications and to remove catalyst poisons prior to further processing. The key substances removed by hydrotreating are sulfur, nitrogen, oxygen, halides, and trace metals. These impurities are removed by reacting hydrogen with the crude fractions over a fixed catalyst bed at elevated temperature. The oil feed is mixed with substantial quantities of hydrogen either before or after it is preheated, generally to 500 F to 800 F. Hydrogen consumption is typically about 70 scf/bbl of feed per percent sulfur, about 320 scf/bbl feed per percent nitrogen, and 180 scf/bbl per percent oxygen removed.[37] Hydrogen demand for various hydroprocessing options for Western Canadian Select (WCS), a DilBit, range from 1,000 to 1,900 scf/bbl.[38] Emissions arise from heating the feed and generating increased amounts of hydrogen, compared to conventional heavy crudes and existing PADD 3 crude slates. More emissions are generated by hydrotreating WCSB tar sands crudes than conventional heavy crudes for several reasons as discussed below.

1. Higher Concentrations of Catalyst Contaminants

Tar sands bitumen contains about 1.5 times more sulfur, nitrogen, oxygen, nickel and vanadium than typical heavy crudes.[39] Thus, much more hydrogen per barrel of feed and higher temperatures would be required to remove the larger amounts of these poisons. Nitrogen content was not included in the DSEIS, Table 3.13-2. Canadian tar sands crudes generally have higher nitrogen content, 3,000 to >6,000 ppm[40] and specifically higher organic nitrogen content, particularly in the naphtha range, than other heavy crudes.[41] This nitrogen is mostly bound up in complex aromatic compounds that require a lot of hydrogen to remove. This affects emissions in five ways.

First, additional hydrotreating is required to remove them, which increases hydrogen and energy input. Second, they deactivate the cracking catalysts, which requires more energy and hence more emissions to achieve the same end result. Third, they increase the nitrogen content of the fuel gas fired in combustion sources, which increases NO_x emissions from all fired sources that use refinery fuel gas. Fourth, nitrogen in WCSB tar sands crudes is present in higher molecular weight compounds than in other heavy crudes and thus requires more hydrogen and energy to remove. Fifth, some of this nitrogen will be converted to ammonia and other chemically bound nitrogen compounds, such as pyridines and pyrroles. These become part of the fuel gas and could increase NO_x from fired sources. They further may be routed to the flares, where they would increase NO_x.

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[37] James H. Gary, Glenn E. Handwerk, and Mark J. Kaiser, Petroleum Refining: Technology and Economics, 5th Ed., CRC Press, 2007, p. 200.
[38] Brierley et al. 2006, Table 6.
[39] See, for example, USGS, 2007, Table 1.
[40] Murray R. Gray, Tutorial on Upgrading of Oilsands Bitumen, University of Alberta, Available at: http://www.ualberta.ca/~gray/Links%20&%20Docs/Web%20Upgrading%20Tutorial.pdf.
[41] See, e.g., James G. Speight, Synthetic Fuels Handbook: Properties, Process, and Performance, McGraw-Hill, 2008, Appendix A;

2. Higher Concentrations of Asphaltenes and Resins

The severity (e.g., temperature, amount of catalyst, hydrogen) of hydrotreating depends on the type of compound the contaminant is bound up in. Lower molecular weight compounds are easier to remove. The difficulty of removal increases in this order: paraffins, naphthenes, and aromatics.[42] Most of the contaminants of concern in WCSB tar sands crudes are bound up in high molecular weight aromatic compounds such as asphaltenes that are difficult to remove, meaning more heat, hydrogen, and catalyst are required. Some tar sands-derived vacuum gas oils (VGOs), for example, contain no paraffins of any kind. All of the molecules are aromatics, naphthenes, or sulfur species that require large amounts of hydrogen to hydrotreat, compared to other heavy crudes.[43]

Asphaltenes and resins generally occur in WCSB bitumens and their crudes in much higher amounts than in other heavy crudes. They are the nonvolatile fractions of petroleum and contain the highest proportions of sulfur, nitrogen, and oxygen.[44] They have a marked effect on refining and result in the deposition of high amounts of coke during thermal processing in the coker. They also form layers of coke in hydrotreating reactors, requiring increased heat input, leading to localized or even general overheating and thus even more coke deposition. This seriously affects catalyst activity resulting in a marked decrease in the rate of desulfurization. They also require more intense processing in the coker required to break them down into lighter products. These factors require increases in steam and heat input, both of which generate combustion emissions, NO_x, SO_x, CO, VOCs, PM10, and PM2.5.

Further, if the crude includes a synthetic crude, SCO, for example, the material has been previously hydrotreated. Thus, the remaining contaminants (e.g., sulfur, nitrogen), while present in small amounts, are much more difficult to remove (due to their chemical form, buried in complex aromatics), requiring higher temperatures, more catalyst, and more hydrogen.[45]

The higher amounts of asphaltenes and resins generate more heavy feedstocks that require more severe processing than lighter feedstocks. The coker, for example, makes more coker distillate and gas oil that must be hydrotreated, compared to conventional heavy crudes. Similarly, the Crude Unit makes more atmospheric and vacuum gas oils that must be hydrotreated.[46] This increases emissions from these units,

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[42] Gary et al., 2007, p. 200.
[43] See, for example, the discussion of hydrotreating and hydrocracking of Athabasca tar sands cuts in Brierley et al. 2006, pp. 11-17.
[44] James G. Speight, The Desulfurization of Heavy Oils and Residua, Marcel Dekker, Inc., 1981, Tables 1-1, 2-2, 2-3, 2-4 and p. 13 and James G. Speight, Synthetic Fuels Handbook: Properties, Process, and Performance, McGraw-Hill, 2008, Tables A.2, A.3, and A.4.
[45] See, for example, Brierley et al. 2006, p. 8 ("The sulfur and nitrogen species left in the kerosene and diesel cuts are the most refractory, difficult-to-treat species that could not be removed in the upgrader's relatively high-pressure hydrotreaters."); Turini et al. 2011 p. 4.
[46] See, for example, Turini et al. 2011, p. 9.

including fugitive VOC emissions from equipment leaks and combustion emissions from burning more fuel.

3. Hydrogen Deficient

WCSB tar sands crudes are hydrogen deficient compared to heavy and conventional crude oils and thus require substantial hydrogen addition during refining, beyond that required to remove contaminants (sulfur, nitrogen, metals). This again means more combustion emissions from burning more fuel.

iii. Hydrogen Production

The WCSB tar sands crudes transported by the Project will require substantial increases in hydrogen production to make up for the deficiency of hydrogen in the tar sands bitumen and to remove contaminants. This will likely require new hydrogen plants or increases in the capacity or throughput of existing hydrogen plants. Emissions from this source were not disclosed in the DSEIS.

Hydrogen is typically manufactured by the steam-methane reforming process in the refining industry. In this process, the feedstock is first desulfurized, mixed with steam, and passed over a catalyst at elevated temperature (1350-1550 F) and pressure (400 psi). Effluent gases are cooled using steam or condensate to about 700 F, at which point carbon monoxide reacts with steam in the presence of iron oxide in a shift converter to produce carbon dioxide and hydrogen. The carbon dioxide is removed by amine washing.

The primary emission sources are a steam methane reforming furnace, dearerator vents, a dedicated flare, a cooling tower, and equipment leaks from pumps, valves, and flanges. The DSEIS should estimate the increase in hydrogen production capacity required to refine up to 830,000 BPD of WCSB crudes and the corresponding increase in emissions from producing this hydrogen.

iv. Coking

The heavy residuum from the Crude Unit is most commonly further processed in a delayed coker at PADD 3 refineries. A coker converts heavy residuals into lighter products that are further treated in other units. A coker converts large hydrocarbon molecules into smaller, more useful molecules using thermal cracking. Carbon is removed as coke in order to produce other smaller, more valuable liquid hydrocarbons by rearranging the chemical bonds of the original molecules.

As WCSB tar sands crudes have significantly higher amounts of vacuum resid, the coker is typically one of the units that must be significantly upgraded. Cokers can be debottlenecked by improving drum cycle time, but most refineries will have to add additional coking capacity to handle the significant increase in heavy resid from refining of WCSB tar sands crudes. This means significant increases in emissions.

The coker feed is heated and charged into a drum where it is thermally cracked under high temperature and pressure (coking). Large hydrocarbon molecules are broken into smaller ones, which rise to the top of the drum, leave as vapors, and are separated in a fractionator column. The material left behind drops out and solidifies, eventually filling the drum with solid coke. After the drum fills with coke, it is switched off-line, steamed out to remove remaining hydrocarbons, and cooled with water. During these steps, the vapors exiting the drum are captured by a closed blowdown system and recovered in the coker fractionator. After steamout, the drum is depressurized by venting to atmosphere through a steam vent before the bottom and top heads are opened. The coke is cut from the drum by drilling with high-pressure water. The drilled coke drops into a pit or pad beneath the coke drum. Following decoking, coke is conveyed from the coker to various storage piles.[47]

Petroleum coke, or "pet coke" is formed as a solid byproduct of the coker. It is mostly carbon with low hydrogen content and high sulfur content. In general, more coke will be produced from the WCSB bitumen blends than from conventional heavy crudes due to the nature of the residuum. The amount of coke depends on the API gravity of the residuum sent to the coker. The API gravity of the residuum from refining DilBits ranges from 6 to 8, or much lower than any other material currently refined in PADD 3. DSEIS, Table 3.13-2. Thus, DilBit residuum will yield large amounts of petroleum coke. If delayed coking, for example, is used for further refining, which is the most common process at PADD 3 refineries, an API 6 residuum would contain 20% carbon by weight and yield 36% coke, or substantially more than most heavy crudes.[48] This coke may be stockpiled and contribute wind-blown fugitive dust or be burned elsewhere as a fuel source, creating additional combustion emissions.

There are five primary sources of air emissions from this process: (1) coker heaters; (2) steam vent; (3) fugitive VOC and H_2S emissions from equipment leaks (e.g., valves, connectors, seals); (4) fugitive dust from coke handling; and (5) combustion emissions if the coke is used as fuel. In addition, significant additional amounts of highly contaminated wastewaters will be generated.

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[47] Oil & Gas Journal, Modern Refinery: Delayed Coking, https://portal.mustangeng.com/pls/portal30/docs/FOLDER/MUSTANGENG/INDUSTRY_POSTERS_CONTENT/DELAYEDCOKINGPOSTERFINAL_SM.PDF. See also: John D. Elliott, Delayed Coker Revamps: Realization of Objectives, http://www.fwc.com/industries/pdf/DELAYED2004.pdf; Paul J. Ellis, Tutorial: Delayed Coking Fundamentals, AIChE 1998 Spring National Meeting, March 8-12, 1998, http://www.cia-inspection.com/DECOKTUT.PDF; Robert A. Meyers, Handbook of Petroleum Refining Processes, 2nd Ed., McGraw Hill, 1996, Chapter 12.2, FW Delayed-Coking Process, Fig. 12.2.9; Robert A. Meyers, Handbook of Petroleum Refining Processes, 3nd Ed., McGraw Hill, 2004, Chapter 12.2, FW Delayed-Coking Process, Fig. 12.2.9; James H. Gary, Glenn E. Handiwerk, and Mark J. Kaiser, Petroleum Refining Technology and Economics, 5th Ed., CRC Press, 2007, Chapter 5; Norman P. Lieberman, Troubleshooting Process Operations, 3rd Ed., PennWell Books, 1991, Chapters 2 and 3; Surinder Parkash, Refining Processes Handbook, Elsevier, 2003.

[48] James G. Speight, Upgrading and Refining of Natural Bitumen and Heavy Oil, In: Coal, Oil, Natural BItumen, Heavy Oil and Peat, Vol. II - Upgrading and Refining of Natural BItumen and Heavy Oil, 2009, p. 253.

Trace metals concentrate in heavy ends and coke is the end of the line. Coke contains very high concentrations of toxic trace metals, including arsenic, beryllium, cadmium, chromium, lead, manganese, mercury, nickel, selenium, and vanadium, among others,[49] which would be emitted from coke storage piles and coke combustion sources.

The high emissions that occur during these activities are so well known that the U.S. Chemical Emergency Preparedness and Prevention Office and the U.S. Occupational Safety & Health Administration ("OSHA") jointly issued a bulletin warning of their hazards in 2003. They report "coke cutting presents serious hazards to workers due to fugitive mists and vapors from cutting and the quench water. Hazardous gases associated with coking operations, such as hydrogen sulfide, carbon monoxide, and trace amounts of polynuclear aromatics, can be emitted from the coke through an opened drum or during processing operations."[50]

The DSEIS did not disclose the significant increase in coker capacity that would be required, the increase in resulting air emissions and wastewater, the increase in coke byproduct, and the potentially significant public health and worker health impacts.

v. Combustion Sources

Refining the WCSB tar sands crudes will require increased firing of virtually every combustion source within the refinery because more heat, steam, and electricity will be required to process the heavier, dirtier crude. The most common combustion sources found in refineries are heaters, boilers, turbines, and flares. Refineries typically have many heaters; big refineries may have over a hundred as they supply process heat to nearly every refining process. There are generally fewer boilers, which generate steam for many refining processes.

The combined emissions from heaters and boilers, especially for NO_x and CO, can be quite large if not adequately controlled. The emissions from heaters and boilers are typically the major source of emissions from many refining processes that are not otherwise separately discussed in this report, e.g., hydrocrackers, reformers, alkylation units. It is reasonable to expect the fired duty of every heater and boiler of every refinery that accepts WCSB tar sands crudes to increase, thus increasing emissions of NO_x, SO_x, CO, VOCs, PM10, and PM2.5.

vi. Wastewater Processing

Wastewaters originate from many sources at a refinery, including crude and product storage tanks, the desalter, coker, hydrotreaters, and hydrocrackers, among others. Condensed steam from coke drum purging and water from hydraulic decoking of coke drums is collected and treated. The hydrotreated naphtha, diesel and other products

[49] Las Brisas Energy Center, LLC, Table A-7. CFB Trace Compound Data.
[50] CEPPO and OSHA, Hazards of Delayed Coker Unit (DCU) Operations, August 2003, http://www.epa.gov/oem/docs/chem/delayed_coker.pdf and OSHA, Hazards of Delayed Coker Unit (DCU) Operations, SHIB 08-29-03, http://www.epa.gov/oem/docs/chem/delayed_coker.pdf, Accessed 11/29/08.

are water washed, generating sour wastewaters. These and other wastewaters reflect the composition of the crude slate and its byproducts.

Thus, wastewaters generated from processing WCSB tar sands crudes in PADD 3 refineries will contain higher concentrations of metals, H_2S and other sulfur compounds, ammonia, and hydrocarbons than from current crude slates. The types of changes discussed here that affect air emissions also affect the quantity and composition of the wastewater. The wastewaters from refining WCSB tar sands crudes would have higher concentrations of chemical oxygen demand (COD), oil and grease, metals, suspended solids, salts, benzene, phenols, and sulphides, among others. Further, emissions from fugitive components and water storage tanks in the sour water handling system would increase.

vii. Accidental Releases

Most of the refineries in PADD 3 were built before current American Petroleum Institute (API) standards were developed to control corrosion and before piping manufacturers began producing carbon steel in compliance with current metallurgical codes. Thus, the metallurgy used throughout these refineries is likely not adequate to handle the unique chemical composition of WCSB tar sands crudes without significant upgrades. There is no assurance that these metallurgical upgrades would occur as they are very expensive and not required by any regulatory framework. Experience with changes in crude slate in California suggest required metallurgical upgrades are ignored, leading to catastrophic accidents.[51]

Both DilBit and SynBit crudes have high Total Acid Numbers (TAN), which indicates high naphthenic acid content. These acids are known to cause corrosion at high temperatures, such as occur in many refining units, e.g., in the feed to cokers. Sulfidation corrosion from elevated concentrations of sulfur compounds in some of the heavier distillation cuts is also a major concern, especially in the vacuum distillation column, coker, and hydrotreater units. The specific suite of sulfur compounds may lead to increased corrosion.

A crude slate change could result in corrosion that leads to significant accidental releases, even if the crude slate is within the current design slate basis, due to compositional differences.

This recently occurred at the Chevron Richmond Refinery in California. This refinery gradually changed crude slates, while staying within its established crude unit design basis for total weight percent sulfur of the blended feed to the crude unit. This is the scenario the DSEIS assumes will mitigate all crude slate issues. However, the sulfur

[51] U.S. Chemical Safety and Hazard Investigation Board, Interim Investigation Report, Chevron Richmond Refinery Fire, Chevron Richmond Refinery, Richmond, California, August 6, 2012, Draft for Public Release, April 15, 2013, Available at; http://www.csb.gov/chevron-refinery-fire/.

composition at Chevron Richmond significantly changed over time.[52] This change increased corrosion rates in the 4-sidecut line, which led to a catastrophic pipe failure in the #4 Crude Unit on August 6, 2012. This release sent 15,000 people from the surrounding area for medical treatment due to the release and created huge black clouds of pollution billowing across the Bay.

These types of accidents can be reasonably expected to result from incorporating WCSB tar sands crudes into PADD 3 refinery slates unless significant upgrades in metallurgy occur, as these crudes have a significant concentration of sulfur in the heavy components of the crude coupled with high TAN and high solids, which aggravate corrosion. The gas oil and vacuum resid piping, for example, may not be able to withstand naphthenic acid or sulfidation corrosion from the WCSB tar sands crudes, leading to catastrophic releases.[53] Catastrophic releases of air pollution from these types of accidents were not considered in the DSEIS.

IV. THE DSEIS UNDERESTIMATED EMISSIONS INCREASES

After explaining why the Project would not affect emissions, the DSEIS presented what it called "[a] conservative hypothetical emissions estimate" for "illustrative purposes." DSEIS, p. 4.15-77. However, it ultimately dismisses these emissions, by arguing that crude oil transported by the proposed Project would be replacing or displacing crude oil from other sources and thus would not result in incremental emission increases. DSEIS, p. 4.15-78. The DSEIS's emission estimates are a gross underestimate for the reasons set out below. They further exclude many important constituents as well as any consideration whatsoever of resulting ambient air quality impacts or the cumulative impacts of modifications to multiple facilities.

a. THE DSEIS UNDERESTIMATES REFINERY EMISSIONS

The DSEIS's emission estimate for refineries processing the WCSB tar sands crudes is based on the potential increase in emissions from two projects: (1) the recently-completed 325,000 BPD Motiva Refinery expansion in Port Arthur, Texas and (2) the proposed new 400,000 BPD Hyperion Refinery in South Dakota. This is not a reasonable basis for estimating emissions from the Project.

First, the DSEIS presents a range of Project emissions for NO_x, CO, VOC, SO_2, and PM, calculated from the Motiva and Hyperion emission estimates. DSEIS, p. 4.15-78. The DSEIS does not explain how it calculated the Project ranges. I was able to reproduce the portion of the range based on Motiva emissions by scaling up the Motiva emissions based on the ratio of Project throughput to Motiva throughput (830,000/325,000 x Motiva emissions). However, I was not able to reproduce the portion

[52] US Chemical Safety and Hazard Investigation Board, 2013, p.34 ("While Chevron stayed under its established crude unit design basis for total wt. % sulfur of the blended feed to the crude unit, the sulfur composition significantly increased over time. This increase in sulfur composition likely increased corrosion rates in the 4-sidecut line.").
[53] See, for example, Turini and others, 2011.

of the range due to Hyperion using this scaling procedure. The portion of the range based on Hyperion emissions apparently contains an error or was calculated using an undisclosed procedure that is not obvious from the context. My calculations are shown in Exhibit C. My estimates of Project emissions, based on reported Motiva and Hyperion emissions, are in the "Project" columns of Exhibit C.

Second, the emissions reported for Hyperion in the DEIS (p. 4.15-77) are based on DENR's estimate in its response to comments. These emissions are inconsistent with the estimates in the revised Hyperion Permit Application. The Application reports much higher emissions of CO (2,005 to 13,955 ton/yr v. 810 ton/yr), NO_x (776 to 1,224 ton/yr v. 687 ton/yr), and SO_2 (853 to 863 ton/yr v. 183 ton/yr).[54]

Third, without limiting emissions to these ranges, there is no assurance that they would be achieved in practice. For reasons discussed elsewhere in this report, it is highly unlikely they would ever be achieved. In fact, they would be significantly exceeded. Thus, to the extent that the EIS relies on these emissions, they should be required as conditions of Project approval.

Fourth, the DSEIS emission estimates assume the imported crude would be processed at "upgraded" refineries. DSEIS, p. 4.15-77. "Upgraded" is not defined. However, most of the refineries in PADD 3 are not "upgraded" but rather are old, outdated refineries that do not have current emission controls or updated metallurgy. The two examples used in the DSEIS to estimate the range in emission increases are not representative of the refineries in PADD 3 or the range of refinery modifications that are possible.

The FEIS assumed that upgrades to accommodate WCSB tar sands crudes would require BACT emission controls at existing poorly controlled refineries, resulting in an overall reduction in emissions relative to baseline conditions. FEIS, p. 3.14-36. This result is highly unlikely due to the widespread permitting shenanigans in the states where most of these refineries are located. Further, in Texas, any facility with a flex permit, or derivative thereof, could skip BACT entirely. See discussion elsewhere in this report.

i. The Hyperion Refinery Is Not Representative of PADD 3 Refineries

Hyperion is not in PADD 3. It is a brand new refinery that is proposed to use current BACT as of 2010. Thus, emissions from this refinery will be substantially lower than from other refineries in PADD 3 that may run WCSB tar sands crudes but are not equipped with current day BACT controls and state of the art metallurgy. Thus, Hyperion represents a lower bound, certainly not representative of the old, poorly controlled refineries with outdated metallurgy in PADD 3. Further, VOC emissions from fugitive equipment leaks were estimated using conventional emission factors that do not

[54] Revised Section 2.2.11. Delayed Cokers, February 2, 2011, Available at: http://denr.sd.gov/Hyperion/Air/200805155RevisionsToApplicationText.pdf.

consider the presence of diluent, discussed elsewhere in this report. Thus, VOC emissions are underestimated.

ii. The Motiva Port Arthur Refinery Is Not Representative of PADD 3 Refineries

This refinery expansion is not representative of others that may be reasonably expected to result from the import of WCSB tar sands crudes for five principal reasons.

First, the Motiva Refinery Crude Expansion Project (CEP) is a new stand-alone refinery with a nominal capacity of 325,000 BPD that will operate side-by-side with the existing Motiva Port Arthur Refinery. As a brand new facility, it will be equipped with BACT as of 2006.[55] Thus, emissions from this expansion will be substantially lower than from other facilities in PADD 3 that may run WCSB tar sands crudes but are not equipped with current day BACT controls and state-of-the art metallurgy. Motiva is not representative of the other old, existing refineries in PADD 3 that were built prior to 1974 and may run WCSB tar sands crudes with only minor modifications to processing units, e.g., expansion in coking capacity or modifications to FCCU. These types of modifications would not reduce emissions or address corrosion problems that may lead to catastrophic accidental releases. In Texas, they likely would not even trigger New Source Review permitting.

Second, the Motiva Refinery expansion was designed primarily to process various grades of Saudi crude and crudes that Shell produces in the Gulf of Mexico. While the Motiva CEP reportedly has the flexibility to process WCSB tar sands crudes and heavy oils from elsewhere, its primary design basis is not WCSB tar sands crudes. This refinery also has significant Saudi investment.[56] The existence and impact of Saudi ownership on the future crude slate was not disclosed in the DSEIS.

Third, the DSEIS provides no support whatsoever for its Motiva emission estimates, not even a single citation.[57] The emissions simply appear in DSEIS Table 4.15-19. The TCEQ does not publish applications on its website and will not provide copies on request to members of the public. A copy may only be obtained through a formal Open Records Act request to TCEQ's Central Records, making public review of the DSEIS's claims as to these emissions more difficult. The DSEIS has failed in its obligation to disclose and inform the public as to Motiva emissions it used to estimate Project air quality impacts.

[55] TCEQ, Flexible Permit Renewal & Amendment and New PSD Permit Source Analysis & Technical Review, Permit no 8404/PSD-TX-1062.
[56] Clifford Krauss, Texas Refinery Is Saudi Foothold in U.S. Market, The New York Times, April 5, 2013. Available at: http://mobile.nytimes.com/2013/04/05/business/texas-refinery-is-saudi-foothold-in-us-market.xml;jsessionid=610050473427C7436B2B3EDE5341096C?f=23.
[57] The FEIS cites these same emissions to TCEQ 2009. FEIS, Table 3.14.3-7. This is "Flexible Permit Renewal & Amendment and New PSD Permit Source Analysis & Technical Review". This document is not in the record and we were unable to obtain a copy from TCEQ.

I made numerous inquiries and ultimately assembled 22 TCEQ documents related to the Motiva CEP in an effort to confirm the reported emissions and develop an understanding of the Motiva project. The emissions reported in the DSEIS for this new refinery conflict with the most current information I was able to obtain from TCEQ. The most current emissions from this project that I found are compared to the DSEIS's estimate in Table 1.

Table 1: Comparison of DSEIS and TCEQ Estimates of Emissions from Motiva CEP (tons/yr)

	DSEIS Table 4.15-19	TCEQ Technical Review
N0x	592.74	-70.0
CO	1489.53	1631.0
VOC	-116.73	-29.0
SOx	1679.73	2056.0
PM	464.37	472.0
C6H6	-0.47	
H_2SO_4	22.24	22.0
H_2S	4.33	3.0
NH_3	125.69	
Cl_2	3.77	

Fourth, I note that as this is an entirely new refinery within an existing refinery, the emissions do not represent the actual increases from the CEP itself, but rather are the results of a netting analysis in which reductions due to shutdowns of other existing units were used to offset increases from the CEP. This is why both NO_x and VOC emissions appear to decrease. These decreases are due to shutdowns, not benefits from refining heavy crudes.

Finally, the VOC emissions estimate did not consider the presence of diluent and was based on widely discredited TCEQ canned VOC emission factors that have been demonstrated to grossly underestimate fugitive emissions from leaking equipment from refineries, as discussed elsewhere in this report.

In sum, the DSEIS has failed to disclose the true impacts of refining WCSB tar sands crudes at PADD 3 refineries.

b. THE DSEIS OMITS POLLUTANTS

The DSEIS included emission estimates for only five criteria pollutants—NO_x, CO, VOCs, SO_x, and PM. The Project can reasonably be expected to increase emissions of sulfuric acid mist, hydrogen sulfide, mercaptans, ammonia, trace metals including mercury and arsenic, and benzene, among many others. The Hyperion estimates that the DSEIS relied on additionally included emission estimates for some of these other pollutants, including 130 tons/yr of organic hazardous air pollutants. As the refineries that would be processing these crudes are surrounded by residential areas, significant public health impacts can be reasonably expected and were not analyzed in the previous Keystone XL EISs or this current DSEIS.

c. THE NO NET INCREASE ASSUMPTION IS WRONG

The air quality impacts assume that "oil that would be transported by the proposed Project (830,000 BPD) would replace historic crude oil supplies or supplant supplies from less stable or more costly sources." DSEIS, p. 4.15-77. Other options are possible, including: (1) increased refining capacity in PADD 3 up to 830,000 BPD, of which 100% would be WCSB tar sands crude and (2) replacing current light oil blend stocks with WCSB tar sands crude without increasing total refining capacity. These other options were not evaluated for air quality impacts and must be considered in an EIS, unless conditions are imposed that would specifically exclude them from occurring.

Exhibit A to Fox Report

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Dr. Fox has 40 years of experience in the field of environmental engineering, including air pollution control (BACT, MACT, LAER, RACT), air quality management, water quality and water supply investigations, hazardous waste investigations, environmental permitting, nuisance investigations, environmental impact reports, CEQA/NEPA documentation, risk assessments, and litigation support.

EDUCATION

Ph.D. Environmental/Civil Engineering, University of California, Berkeley, 1980.
M.S. Environmental/Civil Engineering, University of California, Berkeley, 1975.
B.S. Physics (with high honors), University of Florida, Gainesville, 1971.

REGISTRATION

Registered Professional Engineer: Arizona (2001-present: #36701), California (2002-present; CH 6058), Florida (2001-present; #57886), Georgia (2002-present; #PE027643), Washington (2002-present; #38692), Wisconsin (2005-present; #37595-006)
Board Certified Environmental Engineer, American Academy of Environmental Engineers, Certified in Air Pollution Control (DEE #01-20014), 2002-present
Qualified Environmental Professional (QEP), Institute of Professional Environmental Practice (QEP #02-010007), 2001-present

PROFESSIONAL HISTORY

Environmental Management, Principal, 1981-present
Lawrence Berkeley National Laboratory, Principal Investigator, 1977-1981
University of California, Berkeley, Program Manager, 1976-1977
Bechtel, Inc., Engineer, 1971-1976, 1964-1966

PROFESSIONAL AFFILIATIONS

American Chemical Society (1981-2010)
Phi Beta Kappa (1970-present)
Sigma Pi Sigma (1970-present)

Who's Who Environmental Registry, PH Publishing, Fort Collins, CO, 1992.
Who's Who in the World, Marquis Who's Who, Inc., Chicago, IL, 11th Ed., p. 371, 1993-present.
Who's Who of American Women, Marquis Who's Who, Inc., Chicago, IL, 13th Ed., p. 264, 1984-present.
Who's Who in Science and Engineering, Marquis Who's Who, Inc., New Providence, NJ, 5th Ed., p. 414, 1999-present.
Who's Who in America, Marquis Who's Who, Inc., 59th Ed., 2005.
Guide to Specialists on Toxic Substances, World Environment Center, New York, NY, p. 80, 1980.
National Research Council Committee on Irrigation-Induced Water Quality Problems (Selenium), Subcommittee on Quality Control/Quality Assurance (1985-1990).
National Research Council Committee on Surface Mining and Reclamation, Subcommittee on Oil Shale (1978-80)

REPRESENTATIVE EXPERIENCE

Performed environmental and engineering investigations, as outlined below, for a wide range of industrial and commercial facilities including petroleum refineries and upgrades thereto; reformulated fuels projects; petroleum distribution terminals; coal export terminals; LNG terminals; shale oil plants; coal gasification & liquefaction plants; conventional and thermally enhanced oil production; underground storage tanks; pipelines; gasoline stations; landfills; railyards; hazardous waste treatment facilities; nuclear, hydroelectric, geothermal, wood, biomass, waste, tire-derived fuel, gas, oil, coke and coal-fired power plants; transmission lines; airports; hydrogen plants; petroleum coke calcining plants; coke plants; activated carbon manufacturing facilities; asphalt plants; cement plants; incinerators; flares; manufacturing facilities (e.g., semiconductors, electronic assembly, aerospace components, printed circuit boards, amusement park rides); lanthanide processing plants; ammonia plants; nitric acid plants; urea plants; food processing plants; almond hulling facilities; composting facilities; grain processing facilities; grain elevators; ethanol production facilities; soy bean oil extraction plants; biodiesel plants; paint formulation plants; wastewater treatment plants; marine terminals and ports; gas processing plants; steel mills; iron nugget production facilities; pig iron plant, based on blast furnace technology; direct reduced iron plant; acid regeneration facilities; railcar refinishing facility; battery manufacturing plants; pesticide manufacturing and repackaging facilities; pulp and paper mills; selective catalytic reduction (SCR) systems; halogen acid furnaces; contaminated property redevelopment projects (e.g., Mission Bay, Southern Pacific Railyards, Moscone Center expansion, San Diego Padres Ballpark); residential developments; commercial office parks, campuses, and shopping centers; server farms; transportation plans; and a wide range of mines including sand and gravel, hard rock, limestone, nacholite, coal, molybdenum, gold, zinc, and oil shale.

EXPERT WITNESS/LITIGATION SUPPORT

- For plaintiffs, expert witness in civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for historic modifications (1997-2000) at the Cemex cement plant in Lyons, Colorado. Reviewed produced documents, prepared expert and rebuttal reports on PSD applicability based on NOx emission calculations for a collection of changes considered both individually and collectively. Deposed August 2011. *United States v. Cemex, Inc.*, In U.S. District Court for the District of Colorado (Civil Action No. 09-cv-00019-MSK-MEH).
- For plaintiffs, in civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for historic modifications (1988 – 2000) at James De Young Units 3, 4, and 5. Reviewed produced documents, analyzed CEMS and EIA data, and prepared netting and BACT analyses for NOx, SO2, and PM10. Expert report February 24, 2010 and affidavit February 20, 2010. *Sierra Club v. City of Holland, et al.*, U.S. District Court, Western District of Michigan.
- For plaintiffs, in civil action alleging failure to obtain MACT permit, expert on potential to emit hydrogen chloride (HCl) from a new coal-fired boiler. Reviewed record, estimated HCl emissions, wrote expert report June 2010 and deposed August 2010. *Wildearth Guardian et al. v. Lamar Utilities Board*, Civil Action No. 09-cv-02974, U.S. District Court, District of Colorado.
- For plaintiffs, expert witness on permitting, emission calculations, and wastewater treatment for coal to gasoline plant. Reviewed produced documents. Assisted in preparation of comments on draft minor source permit. Wrote two affidavits on key issues in case. Presented direct and rebuttal testimony 10/27 - 10/28/10 on permit enforceability and failure to properly calculate potential to emit, including underestimate of flaring emissions and omission of VOC and CO emissions from wastewater treatment, cooling tower, tank roof landings, and malfunctions. *Sierra Club, Ohio Valley Environmental Coalition, Coal River Mountain Watch, West Virginia Highlands Conservancy v. John Benedict, Director, Division of Air Quality, West Virginia Department of Environmental Protection and TransGas Development System, LLC*, Appeal No. 10-01-AQB.
- For plaintiffs, expert on BACT emission limits for gas-fired combined cycle power plant. Prepared declaration in support of CBE's Opposition to the United States' Motion for Entry of Proposed Amended Consent Decree. Assisted in settlement discussions. *U.S. EPA, Plaintiff, Communities for a Better Environment, Intervenor Plaintiff, v. Pacific Gas & Electric Company, et al.*, U.S. District Court, Northern District of California, San Francisco Division, Case No. C-09-4503 SI.

- Technical expert in confidential settlement discussions with large coal-fired utility on BACT control technology and emission limits for NOx, SO2, PM, PM2.5, and CO for new natural gas fired combined cycle and simple cycle turbines with oil backup. (July 2010). Case settled.
- For plaintiffs, expert witness in remedy phase of civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for historic modifications (1998-99) at Gallagher Units 1 and 3. Reviewed produced documents, prepared expert and rebuttal reports on historic and current-day BACT for SO2, control costs, and excess emissions of SO2. Deposed 11/18/09. *United States et al. v. Cinergy, et al.*, In U.S. District Court for the Southern District of Indiana, Indianapolis Division, Civil Action No. IP99-1693 C-M/S. Settled 12/22/09.
- For plaintiffs, expert witness on MACT, BACT for NOx, and enforceability in an administrative appeal of draft state air permit issued for four 300-MW pet-coke-fired CFBs. Reviewed produced documents and prepared prefiled testimony. Deposed 10/8/09 and 11/9/09. Testified 11/10/09. *Application of Las Brisas Energy Center, LLC for State Air Quality Permit*; before the State Office of Administrative Hearings, Texas. Permit remanded 3/29/10 as LBEC failed to meet burden of proof on a number of issues including MACT.
- For defense, expert witness in unlawful detainer case involving a gasoline station, minimart, and residential property with contamination from leaking underground storage tanks. Reviewed agency files and inspected site. Presented expert testimony on July 6, 2009, on causes of, nature and extent of subsurface contamination. *A. Singh v. S. Assaedi,* in Contra Costa County Superior Court, CA. Settled August 2009.
- For plaintiffs, expert witness on netting and enforceability for refinery being upgraded to process tar sands crude. Reviewed produced documents. Prepared expert and rebuttal reports addressing use of emission factors for baseline, omitted sources including coker, flares, tank landings and cleaning, and enforceability. Deposed. *In the Matter of Objection to the Issuance of Significant Source Modification Permit No. 089-25484-00453 to BP Products North America Inc., Whiting Business Unit, Save the Dunes Council, Inc., Sierra Club., Inc., Hoosier Environmental Council et al., Petitioners, B. P. Products North American*, *Respondents/Permittee,* before the Indiana Office of Environmental Adjudication.
- For plaintiffs, expert witness on BACT, MACT, and enforceability in appeal of Title V permit issued to 600 MW coal-fired power plant burning Powder River Basin coal. Prepared technical comments on draft air permit. Reviewed record on appeal, drafted BACT, MACT, and enforceability pre-filed testimony. Drafted MACT and enforceability pre-filed rebuttal testimony. Deposed March 24, 2009. Testified June 10, 2009. *In Re: Southwestern Electric Power Company*, Arkansas Pollution Control and Ecology Commission, Consolidated Docket No. 08-006-P. Recommended Decision issued December 9, 2009 upholding issued permit. Commission adopted Recommended Decision January 22, 2010.

- For plaintiffs, expert witness in remedy phase of civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for historic modifications (1989-1992) at Wabash Units 2, 3 and 5. Reviewed produced documents, prepared expert and rebuttal report on historic and current-day BACT for NOx and SO2, control costs, and excess emissions of NOx, SO2, and mercury. Deposed 10/21/08. *United States et al. v. Cinergy, et al.*, In U.S. District Court for the Southern District of Indiana, Indianapolis Division, Civil Action No. IP99-1693 C-M/S. Testified 2/3/09. Memorandum Opinion & Order 5-29-09 requiring shutdown of Wabash River Units 2, 3, 5 by September 30, 2009, run at baseline until shutdown, and permanently surrender SO2 emission allowances.
- For plaintiffs, expert witness in liability phase of civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for three historic modifications (1997-2001) at two portland cement plants involving three cement kilns. Reviewed produced documents, analyzed CEMS data covering subject period, prepared netting analysis for NOx, SO_2 and CO, and prepared expert and rebuttal reports. *United States v. Cemex California Cement*, In U.S. District Court for the Central District of California, Eastern Division, Case No. ED CV 07-00223-GW (JCRx), Settled 1/15/09.
- For intervenors Clean Wisconsin and Citizens Utility Board, prepared data requests, reviewed discovery and expert report. Prepared prefiled direct, rebuttal and surrebuttal testimony on cost to extend life of existing Oak Creek Units 5-8 and cost to address future regulatory requirements to determine whether to control or shutdown one or more of the units. Oral testimony 2/5/08. Application for a Certificate of Authority to Install Wet Flue Gas Desulfurization and Selective Catalytic Reduction Facilities and Associated Equipment for Control of Sulfur Dioxide and Nitrogen Oxide Emissions at Oak Creek Power Plant Units 5, 6, 7 and 8, WPSC Docket No. 6630-CE-299.
- For plaintiffs, expert witness on alternatives analysis and BACT for NOx, SO2, total PM10, and sulfuric acid mist in appeal of PSD permit issued to 1200 MW coal fired power plant burning Powder River Basin and/or Central Appalachian coal (Longleaf). Assisted in drafting technical comments on NOx on draft permit. Prepared expert disclosure. Presented 8+ days of direct and rebuttal expert testimony. Attended all 21 days of evidentiary hearing from 9/5/07 – 10/30/07 assisting in all aspects of hearing. *Friends of the Chatahooche and Sierra Club v. Dr. Carol Couch, Director, Environmental Protection Division of Natural Resources Department, Respondent, and Longleaf Energy Associates, Intervener*. ALJ Final Decision 1/11/08 denying petition. ALJ Order vacated & remanded for further proceedings, Fulton County Superior Court, 6/30/08. Court of Appeals of GA remanded the case with directions that the ALJ's final decision be vacated to consider the evidence under the correct standard of review, July 9, 2009. The ALJ issued an opinion April 2, 2010 in favor of the applicant. Final permit issued April 2010.
- For plaintiffs, expert witness on diesel exhaust in inverse condemnation case in which Port expanded maritime operations into residential neighborhoods, subjecting plaintiffs to noise,

light, and diesel fumes. Measured real-time diesel particulate concentrations from marine vessels and tug boats on plaintiffs' property. Reviewed documents, depositions, DVDs, and photographs provided by counsel. Deposed. Testified October 24, 2006. *Ann Chargin, Richard Hackett, Carolyn Hackett, et al. v. Stockton Port District*, Superior Court of California, County of San Joaquin, Stockton Branch, No. CV021015. Judge ruled for plaintiffs.

- For plaintiffs, expert witness on NOx emissions and BACT in case alleging failure to obtain necessary permits and install controls on gas-fired combined-cycle turbines. Prepared and reviewed (applicant analyses) of NOx emissions, BACT analyses (water injection, SCR, ultra low NOx burners), and cost-effectiveness analyses based on site visit, plant operating records, stack tests, CEMS data, and turbine and catalyst vendor design information. Participated in negotiations to scope out consent order. *United States v. Nevada Power.* Case settled June 2007, resulting in installation of dry low NOx burners (5 ppm NOx averaged over 1 hr) on four units and a separate solar array at a local business.
- For plaintiffs, expert witness in appeal of PSD permit issued to 850 MW coal fired boiler burning Powder River Basin coal (Iatan Unit 2) on BACT for particulate matter, sulfuric acid mist and opacity and emission calculations for alleged historic violations of PSD. Assisted in drafting technical comments, petition for review, discovery requests, and responses to discovery requests. Reviewed produced documents. Prepared expert report on BACT for particulate matter. Assisted with expert depositions. Deposed February 7, 8, 27, 28, 2007. *In Re PSD Construction Permit Issued to Great Plains Energy, Kansas City Power & Light – Iatan Generating Station, Sierra Club v. Missouri Department of Natural Resources, Great Plains Energy, and Kansas City Power & Light.* Case settled March 27, 2007, providing offsets for over 6 million ton/yr of CO2 and lower NOx and SO_2 emission limits.
- For plaintiffs, expert witness in remedy phase of civil action relating to alleged violations of the Clean Air Act, Prevention of Significant Deterioration, for historic modifications of coal-fired boilers and associated equipment. Reviewed produced documents, prepared expert report on cost to retrofit 24 coal-fired power plants with scrubbers designed to remove 99% of the sulfur dioxide from flue gases. Prepared supplemental and expert report on cost estimates and BACT for SO2 for these 24 complaint units. Deposed 1/30/07 and 3/14/07. *United States and State of New York et al. v. American Electric Power,* In U.S. District Court for the Southern District of Ohio, Eastern Division, Consolidated Civil Action Nos. C2-99-1182 and C2-99-1250. Settlement announced 10/9/07.
- For plaintiffs, expert witness on BACT, enforceability, and alternatives analysis in appeal of PSD permit issued for a 270-MW pulverized coal fired boiler burning Powder River Basin coal (City Utilities Springfield Unit 2). Reviewed permitting file and assisted counsel draft petition and prepare and respond to interrogatories and document requests. Reviewed interrogatory responses and produced documents. Assisted with expert depositions. Deposed August 2005. Evidentiary hearings October 2005. *In the Matter of Linda*

Chipperfield and Sierra Club v. Missouri Department of Natural Resources. Missouri Supreme Court denied review of adverse lower court rulings August 2007.

- For plaintiffs, expert witness in civil action relating to plume touchdowns at AEP's Gavin coal-fired power plant. Assisted counsel draft interrogatories and document requests. Reviewed responses to interrogatories and produced documents. Prepared expert report "Releases of Sulfuric Acid Mist from the Gavin Power Station." The report evaluates sulfuric acid mist releases to determine if AEP complied with the requirements of CERCLA Section 103(a) and EPCRA Section 304. This report also discusses the formation, chemistry, release characteristics, and abatement of sulfuric acid mist in support of the claim that these releases present an imminent and substantial endangerment to public health under Section 7002(a)(1)(B) of the Resource Conservation and Recovery Act ("RCRA"). *Citizens Against Pollution v. Ohio Power Company*, In the U.S. District Court for the Southern District of Ohio, Eastern Division, Civil Action No. 2-04-cv-371. Case settled 12-8-06.

- For petitioners, expert witness in contested case hearing on BACT, enforceability, and emission estimates for an air permit issued to a 500-MW supercritical Power River Basin coal-fired boiler (Weston Unit 4). Assisted counsel prepare comments on draft air permit and respond to and draft discovery. Reviewed produced file, deposed (7/05), and prepared expert report on BACT and enforceability. Evidentiary hearings September 2005. *In the Matter of an Air Pollution Control Construction Permit Issued to Wisconsin Public Service Corporation for the Construction and Operation of a 500 MW Pulverized Coal-fired Power Plant Known as Weston Unit 4 in Marathon County, Wisconsin*, Case No. IH-04-21. The Final Order, issued 2/10/06, lowered the NOx BACT limit from 0.07 lb/MMBtu to 0.06 lb/MMBtu based on a 30-day average, added a BACT SO2 control efficiency, and required a 0.0005% high efficiency drift eliminator as BACT for the cooling tower. The modified permit, including these provisions, was issued 3/28/07. Additional appeals in progress.
- For plaintiffs, adviser on technical issues related to Citizen Suit against U.S. EPA regarding failure to update New Source Performance Standards for petroleum refineries, 40 CFR 60, Subparts J, VV, and GGG. *Our Children's Earth Foundation and Sierra Club v. U.S. EPA et al.* Case settled July 2005. CD No. C 05-00094 CW, U.S. District Court, Northern District of California – Oakland Division. Proposed revisions to standards of performance for petroleum refineries published 72 FR 27178 (5/14/07).
- For interveners, reviewed proposed Consent Decree settling Clean Air Act violations due to historic modifications of boilers and associated equipment at two coal-fired power plants. In response to stay order, reviewed the record, selected one representative activity at each of seven generating units, and analyzed to identify CAA violations. Identified NSPS and NSR violations for NOx, SO_2, PM/PM10, and sulfuric acid mist. Summarized results in an expert report. *United States of America, and Michael A. Cox, Attorney General of the State of Michigan, ex rel. Michigan Department of Environmental Quality, Plaintiffs, and Clean*

Wisconsin, Sierra Club, and Citizens' Utility Board, Intervenors, v. Wisconsin Electric Power Company, Defendant, U.S. District Court for the Eastern District of Wisconsin, Civil Action No. 2:03-CV-00371-CNC. Order issued 10-1-07 denying petition.

- For a coalition of Nevada labor organizations (ACE), reviewed preliminary determination to issue a Class I Air Quality Operating Permit to Construct and supporting files for a 250-MW pulverized coal-fired boiler (Newmont). Prepared about 100 pages of technical analyses and comments on BACT, MACT, emission calculations, and enforceability. Assisted counsel draft petition and reply brief appealing PSD permit to U.S. EPA Environmental Appeals Board (EAB). Order denying review issued 12/21/05. *In re Newmont Nevada Energy Investment, LLC, TS Power Plant*, PSD Appeal No. 05-04 (EAB 2005).
- For petitioners and plaintiffs, reviewed and prepared comments on air quality and hazardous waste based on negative declaration for refinery ultra low sulfur diesel project located in SCAQMD. Reviewed responses to comments and prepared responses. Prepared declaration and presented oral testimony before SCAQMD Hearing Board on exempt sources (cooling towers) and calculation of potential to emit under NSR. Petition for writ of mandate filed March 2005. Case remanded by Court of Appeals to trial court to direct SCAQMD to re-evaluate the potential environmental significance of NOx emissions resulting from the project in accordance with court's opinion. California Court of Appeals, Second Appellate Division, on December 18, 2007, affirmed in part (as to baseline) and denied in part. *Communities for a Better Environment v. South Coast Air Quality Management District and ConocoPhillips and Carlos Valdez et al v. South Coast Air Quality Management District and ConocoPhillips.* Certified for partial publication 1/16/08. Appellate Court opinion upheld by CA Supreme Court 3/15/10.
- For amici seeking to amend a proposed Consent Decree to settle alleged NSR violations at Chevron refineries, reviewed proposed settlement, related files, subject modifications, and emission calculations. Prepared declaration on emission reductions, identification of NSR and NSPS violations, and BACT/LAER for FCCUs, heaters and boilers, flares, and sulfur recovery plants. *U.S. et al. v. Chevron U.S.A.*, Northern District of California, Case No. C 03-04650. Memorandum and Order Entering Consent Decree issued June 2005. Case No. C 03-4650 CRB.
- For petitioners, prepared declaration on enforceability of periodic monitoring requirements, in response to EPA's revised interpretation of 40 CFR 70.6(c)(1). This revision limited additional monitoring required in Title V permits. 69 FR 3203 (Jan. 22, 2004). *Environmental Integrity Project et al. v. EPA* (U.S. Court of Appeals for the District of Columbia). Court ruled the Act requires all Title V permits to contain monitoring requirements to assure compliance. *Sierra Club v. EPA*, 536 F.3d 673 (D.C. Cir. 2008).
- For interveners in application for authority to construct a 500 MW supercritical coal-fired generating unit before the Wisconsin Public Service Commission, prepared pre-filed written

direct and rebuttal testimony with oral cross examination and rebuttal on BACT and MACT (Weston 4). Prepared written comments on BACT, MACT, and enforceability on draft air permit for same facility.

- For property owners in Nevada, evaluated the environmental impacts of a 1,450-MW coal-fired power plant proposed in a rural area adjacent to the Black Rock Desert and Granite Range, including emission calculations, air quality modeling, comments on proposed use permit to collect preconstruction monitoring data, and coordination with agencies and other interested parties. Project cancelled.
- For environmental organizations, reviewed draft PSD permit for a 600-MW coal-fired power plant in West Virginia (Longview). Prepared comments on permit enforceability; coal washing; BACT for SO_2 and PM10; Hg MACT; and MACT for HCl, HF, non-Hg metallic HAPs, and enforceability. Assist plaintiffs draft petition appealing air permit. Retained as expert to develop testimony on MACT, BACT, offsets, enforceability. Participate in settlement discussions. Case settled July 2004.
- For petitioners, reviewed record produced in discovery and prepared affidavit on emissions of carbon monoxide and volatile organic compounds during startup of GE 7FA combustion turbines to successfully establish plaintiff standing. *Sierra Club et al. v. Georgia Power Company* (Northern District of Georgia).
- For building trades, reviewed air quality permitting action for 1500-MW coal-fired power plant before the Kentucky Department for Environmental Protection (Thoroughbred).
- For petitioners, expert witness in administrative appeal of the PSD/Title V permit issued to a 1500-MW coal-fired power plant. Reviewed over 60,000 pages of produced documents, prepared discovery index, identified and assembled plaintiff exhibits. Deposed. Assisted counsel in drafting discovery requests, with over 30 depositions, witness cross examination, and brief drafting. Presented over 20 days of direct testimony, rebuttal and sur-rebuttal, with cross examination on BACT for NOx, SO_2, and PM/PM10; MACT for Hg and non-Hg metallic HAPs; emission estimates for purposes of Class I and II air modeling; risk assessment; and enforceability of permit limits. Evidentiary hearings from November 2003 to June 2004. *Sierra Club et al. v. Natural Resources & Environmental Protection Cabinet, Division of Air Quality and Thoroughbred Generating Company et al.* Hearing Officer Decision issued August 9, 2005 finding in favor of plaintiffs on counts as to risk, BACT (IGCC/CFB, NOx, SO_2, Hg, Be), single source, enforceability, and errors and omissions. Assist counsel draft exceptions. Cabinet Secretary issued Order April 11, 2006 denying Hearing Offer's report, except as to NOx BACT, Hg, 99% SO2 control and certain errors and omissions.
- For citizens group in Massachusetts, reviewed, commented on, and participated in permitting of pollution control retrofits of coal-fired power plant (Salem Harbor).

- Assisted citizens group and labor union challenge issuance of conditional use permit for a 317,000 ft^2 discount store in Honolulu without any environmental review. In support of a motion for preliminary injunction, prepared 7-page declaration addressing public health impacts of diesel exhaust from vehicles serving the Project. In preparation for trial, prepared 20-page preliminary expert report summarizing results of diesel exhaust and noise measurements at two big box retail stores in Honolulu, estimated diesel PM10 concentrations for Project using ISCST, prepared a cancer health risk assessment based on these analyses, and evaluated noise impacts.
- Assisted environmental organizations to challenge the DOE Finding of No Significant Impact (FONSI) for the Baja California Power and Sempra Energy Resources Cross-Border Transmissions Lines in the U.S. and four associated power plants located in Mexico (DOE EA-1391). Prepared 20-page declaration in support of motion for summary judgment addressing emissions, including CO_2 and NH_3, offsets, BACT, cumulative air quality impacts, alternative cooling systems, and water use and water quality impacts. Plaintiff's motion for summary judgment granted in part. U.S. District Court, Southern District decision concluded that the Environmental Assessment and FONSI violated NEPA and the APA due to their inadequate analysis of the potential controversy surrounding the project, water impacts, impacts from NH_3 and CO_2, alternatives, and cumulative impacts. *Border Power Plant Working Group v. Department of Energy and Bureau of Land Management*, Case No. 02-CV-513-IEG (POR) (May 2, 2003).
- For Sacramento school, reviewed draft air permit issued for diesel generator located across from playfield. Prepared comments on emission estimates, enforceability, BACT, and health impacts of diesel exhaust. Case settled. BUG trap installed on the diesel generator.
- Assisted unions in appeal of Title V permit issued by BAAQMD to carbon plant that manufactured coke. Reviewed District files, identified historic modifications that should have triggered PSD review, and prepared technical comments on Title V permit. Reviewed responses to comments and assisted counsel draft appeal to BAAQMD hearing board, opening brief, motion to strike, and rebuttal brief. Case settled.
- Assisted California Central Coast city obtain controls on a proposed new city that would straddle the Ventura-Los Angeles County boundary. Reviewed several environmental impact reports, prepared an air quality analysis, a diesel exhaust health risk assessment, and detailed review comments. Governor intervened and State dedicated the land for conservation purposes April 2004.
- Assisted Central California city to obtain controls on large alluvial sand quarry and asphalt plant proposing a modernization. Prepared comments on Negative Declaration on air quality, public health, noise, and traffic. Evaluated process flow diagrams and engineering reports to determine whether proposed changes increased plant capacity or substantially modified plant operations. Prepared comments on application for categorical exemption from CEQA. Presented testimony to County Board of Supervisors. Developed controls to mitigate impacts. Assisted counsel draft Petition for Writ. Case settled June 2002.

Substantial improvements in plant operations were obtained including cap on throughput, dust control measures, asphalt plant loadout enclosure, and restrictions on truck routes.

- Assisted oil companies on the California Central Coast in defending class action citizen's lawsuit alleging health effects due to emissions from gas processing plant and leaking underground storage tanks. Reviewed regulatory and other files and advised counsel on merits of case. Case settled November 2001.
- Assisted oil company on the California Central Coast in defending property damage claims arising out of a historic oil spill. Reviewed site investigation reports, pump tests, leachability studies, and health risk assessments, participated in design of additional site characterization studies to assess health impacts, and advised counsel on merits of case. Prepare health risk assessment.
- Assisted unions in appeal of Initial Study/Negative Declaration ("IS/ND") for an MTBE phaseout project at a Bay Area refinery. Reviewed IS/ND and supporting agency permitting files and prepared technical comments on air quality, groundwater, and public health impacts. Reviewed responses to comments and final IS/ND and ATC permits and assisted counsel to draft petitions and briefs appealing decision to Air District Hearing Board. Presented sworn direct and rebuttal testimony with cross examination on groundwater impacts of ethanol spills on hydrocarbon contamination at refinery. Hearing Board ruled 5 to 0 in favor of appellants, remanding ATC to district to prepare an EIR.
- Assisted Florida cities in challenging the use of diesel and proposed BACT determinations in prevention of significant deterioration (PSD) permits issued to two 510-MW simple cycle peaking electric generating facilities and one 1,080-MW simple cycle/combined cycle facility. Reviewed permit applications, draft permits, and FDEP engineering evaluations, assisted counsel in drafting petitions and responding to discovery. Participated in settlement discussions. Cases settled or applications withdrawn.
- Assisted large California city in federal lawsuit alleging peaker power plant was violating its federal permit. Reviewed permit file and applicant's engineering and cost feasibility study to reduce emissions through retrofit controls. Advised counsel on feasible and cost-effective NOx, SOx, and PM10 controls for several 1960s diesel-fired Pratt and Whitney peaker turbines. Case settled.
- Assisted coalition of Georgia environmental groups in evaluating BACT determinations and permit conditions in PSD permits issued to several large natural gas-fired simple cycle and combined-cycle power plants. Prepared technical comments on draft PSD permits on BACT, enforceability of limits, and toxic emissions. Reviewed responses to comments, advised counsel on merits of cases, participated in settlement discussions, presented oral and written testimony in adjudicatory hearings, and provided technical assistance as required. Cases settled or won at trial.

- Assisted construction unions in review of air quality permitting actions before the Indiana Department of Environmental Management ("IDEM") for several natural gas-fired simple cycle peaker and combined cycle power plants.
- Assisted coalition of towns and environmental groups in challenging air permits issued to 523 MW dual fuel (natural gas and distillate) combined-cycle power plant in Connecticut. Prepared technical comments on draft permits and 60 pages of written testimony addressing emission estimates, startup/shutdown issues, BACT/LAER analyses, and toxic air emissions. Presented testimony in adjudicatory administrative hearings before the Connecticut Department of Environmental Protection in June 2001 and December 2001.
- Assisted various coalitions of unions, citizens groups, cities, public agencies, and developers in licensing and permitting of over 110 coal, gas, oil, biomass, and pet coke-fired power plants generating over 75,000 MW of electricity. These included base-load, combined cycle, simple cycle, and peaker power plants in Alaska, Arizona, Arkansas, California, Colorado, Georgia, Florida, Illinois, Indiana, Kentucky, Michigan, Missouri, Ohio, Oklahoma, Oregon, Texas, West Virginia, Wisconsin, and elsewhere. Prepared analyses of and comments on applications for certification, preliminary and final staff assessments, and various air, water, wastewater, and solid waste permits issued by local agencies. Presented written and oral testimony before various administrative bodies on hazards of ammonia use and transportation, health effects of air emissions, contaminated property issues, BACT/LAER issues related to SCR and SCONOx, criteria and toxic pollutant emission estimates, MACT analyses, air quality modeling, water supply and water quality issues, and methods to reduce water use, including dry cooling, parallel dry-wet cooling, hybrid cooling, and zero liquid discharge systems.
- Assisted unions, cities, and neighborhood associations in challenging an EIR issued for the proposed expansion of the Oakland Airport. Reviewed two draft EIRs and prepared a health risk assessment and extensive technical comments on air quality and public health impacts. The California Court of Appeals, First Appellate District, ruled in favor of appellants and plaintiffs, concluding that the EIR "2) erred in using outdated information in assessing the emission of toxic air contaminants (TACs) from jet aircraft; 3) failed to support its decision not to evaluate the health risks associated with the emission of TACs with meaningful analysis," thus accepting my technical arguments and requiring the Port to prepare a new EIR. See *Berkeley Keep Jets Over the Bay Committee, City of San Leandro, and City of Alameda et al. v. Board of Port Commissioners* (August 30, 2001) 111 Cal.Rptr.2d 598.

- Assisted lessor of former gas station with leaking underground storage tanks and TCE contamination from adjacent property. Lessor held option to purchase, which was forfeited based on misrepresentation by remediation contractor as to nature and extent of contamination. Remediation contractor purchased property. Reviewed regulatory agency files and advised counsel on merits of case. Case not filed.
- Advised counsel on merits of several pending actions, including a Proposition 65 case involving groundwater contamination at an explosives manufacturing firm and two former gas stations with leaking underground storage tanks.
- Assisted defendant foundry in Oakland in a lawsuit brought by neighbors alleging property contamination, nuisance, trespass, smoke, and health effects from foundry operation. Inspected and sampled plaintiff's property. Advised counsel on merits of case. Case settled.
- Assisted business owner facing eminent domain eviction. Prepared technical comments on a negative declaration for soil contamination and public health risks from air emissions from a proposed redevelopment project in San Francisco in support of a CEQA lawsuit. Case settled.
- Assisted neighborhood association representing residents living downwind of a Berkeley asphalt plant in separate nuisance and CEQA lawsuits. Prepared technical comments on air quality, odor, and noise impacts, presented testimony at commission and council meetings, participated in community workshops, and participated in settlement discussions. Cases settled. Asphalt plant was upgraded to include air emission and noise controls, including vapor collection system at truck loading station, enclosures for noisy equipment, and improved housekeeping.
- Assisted a Fortune 500 residential home builder in claims alleging health effects from faulty installation of gas appliances. Conducted indoor air quality study, advised counsel on merits of case, and participated in discussions with plaintiffs. Case settled.
- Assisted property owners in Silicon Valley in lawsuit to recover remediation costs from insurer for large TCE plume originating from a manufacturing facility. Conducted investigations to demonstrate sudden and accidental release of TCE, including groundwater modeling, development of method to date spill, preparation of chemical inventory, investigation of historical waste disposal practices and standards, and on-site sewer and storm drainage inspections and sampling. Prepared declaration in opposition to motion for summary judgment. Case settled.
- Assisted residents in east Oakland downwind of a former battery plant in class action lawsuit alleging property contamination from lead emissions. Conducted historical research and dry deposition modeling that substantiated claim. Participated in mediation at JAMS. Case settled.

- Assisted property owners in West Oakland who purchased a former gas station that had leaking underground storage tanks and groundwater contamination. Reviewed agency files and advised counsel on merits of case. Prepared declaration in opposition to summary judgment. Prepared cost estimate to remediate site. Participated in settlement discussions. Case settled.
- Consultant to counsel representing plaintiffs in two Clean Water Act lawsuits involving selenium discharges into San Francisco Bay from refineries. Reviewed files and advised counsel on merits of case. Prepared interrogatory and discovery questions, assisted in deposing opposing experts, and reviewed and interpreted treatability and other technical studies. Judge ruled in favor of plaintiffs.
- Assisted oil company in a complaint filed by a resident of a small California beach community alleging that discharges of tank farm rinse water into the sanitary sewer system caused hydrogen sulfide gas to infiltrate residence, sending occupants to hospital. Inspected accident site, interviewed parties to the event, and reviewed extensive agency files related to incident. Used chemical analysis, field simulations, mass balance calculations, sewer hydraulic simulations with SWMM44, atmospheric dispersion modeling with SCREEN3, odor analyses, and risk assessment calculations to demonstrate that the incident was caused by a faulty drain trap and inadequate slope of sewer lateral on resident's property. Prepared a detailed technical report summarizing these studies. Case settled.
- Assisted large West Coast city in suit alleging that leaking underground storage tanks on city property had damaged the waterproofing on downgradient building, causing leaks in an underground parking structure. Reviewed subsurface hydrogeologic investigations and evaluated studies conducted by others documenting leakage from underground diesel and gasoline tanks. Inspected, tested, and evaluated waterproofing on subsurface parking structure. Waterproofing was substandard. Case settled.
- Assisted residents downwind of gravel mine and asphalt plant in Siskiyou County, California, in suit to obtain CEQA review of air permitting action. Prepared two declarations analyzing air quality and public health impacts. Judge ruled in favor of plaintiffs, closing mine and asphalt plant.
- Assisted defendant oil company on the California Central Coast in class action lawsuit alleging property damage and health effects from subsurface petroleum contamination. Reviewed documents, prepared risk calculations, and advised counsel on merits of case. Participated in settlement discussions. Case settled.
- Assisted defendant oil company in class action lawsuit alleging health impacts from remediation of petroleum contaminated site on California Central Coast. Reviewed documents, designed and conducted monitoring program, and participated in settlement discussions. Case settled.

- Consultant to attorneys representing irrigation districts and municipal water districts to evaluate a potential challenge of USFWS actions under CVPIA section 3406(b)(2). Reviewed agency files and collected and analyzed hydrology, water quality, and fishery data. Advised counsel on merits of case. Case not filed.
- Assisted residents downwind of a Carson refinery in class action lawsuit involving soil and groundwater contamination, nuisance, property damage, and health effects from air emissions. Reviewed files and provided advise on contaminated soil and groundwater, toxic emissions, and health risks. Prepared declaration on refinery fugitive emissions. Prepared deposition questions and reviewed deposition transcripts on air quality, soil contamination, odors, and health impacts. Case settled.
- Assisted residents downwind of a Contra Costa refinery who were affected by an accidental release of naphtha. Characterized spilled naphtha, estimated emissions, and modeled ambient concentrations of hydrocarbons and sulfur compounds. Deposed. Presented testimony in binding arbitration at JAMS. Judge found in favor of plaintiffs.
- Assisted residents downwind of Contra Costa County refinery in class action lawsuit alleging property damage, nuisance, and health effects from several large accidents as well as routine operations. Reviewed files and prepared analyses of environmental impacts. Prepared declarations, deposed, and presented testimony before jury in one trial and judge in second. Case settled.
- Assisted business owner claiming damages from dust, noise, and vibration during a sewer construction project in San Francisco. Reviewed agency files and PM10 monitoring data and advised counsel on merits of case. Case settled.
- Assisted residents downwind of Contra Costa County refinery in class action lawsuit alleging property damage, nuisance, and health effects. Prepared declaration in opposition to summary judgment, deposed, and presented expert testimony on accidental releases, odor, and nuisance before jury. Case thrown out by judge, but reversed on appeal and not retried.
- Presented testimony in small claims court on behalf of residents claiming health effects from hydrogen sulfide from flaring emissions triggered by a power outage at a Contra Costa County refinery. Analyzed meteorological and air quality data and evaluated potential health risks of exposure to low concentrations of hydrogen sulfide. Judge awarded damages to plaintiffs.
- Assisted construction unions in challenging PSD permit for an Indiana steel mill. Prepared technical comments on draft PSD permit, drafted 70-page appeal of agency permit action to the Environmental Appeals Board challenging permit based on faulty BACT analysis for electric arc furnace and reheat furnace and faulty permit conditions, among others, and drafted briefs responding to four parties. EPA Region V and the EPA General Counsel intervened as amici, supporting petitioners. EAB ruled in favor of petitioners, remanding permit to IDEM on three key issues, including BACT for the reheat furnace and lead

emissions from the EAF. Drafted motion to reconsider three issues. Prepared 69 pages of technical comments on revised draft PSD permit. Drafted second EAB appeal addressing lead emissions from the EAF and BACT for reheat furnace based on European experience with SCR/SNCR. Case settled. Permit was substantially improved. See *In re: Steel Dynamics, Inc.*, PSD Appeal Nos. 99-4 & 99-5 (EAB June 22, 2000).

- Assisted defendant urea manufacturer in Alaska in negotiations with USEPA to seek relief from penalties for alleged violations of the Clean Air Act. Reviewed and evaluated regulatory files and monitoring data, prepared technical analysis demonstrating that permit limits were not violated, and participated in negotiations with EPA to dismiss action. Fines were substantially reduced and case closed.
- Assisted construction unions in challenging PSD permitting action for an Indiana grain mill. Prepared technical comments on draft PSD permit and assisted counsel draft appeal of agency permit action to the Environmental Appeals Board challenging permit based on faulty BACT analyses for heaters and boilers and faulty permit conditions, among others. Case settled.
- As part of a consent decree settling a CEQA lawsuit, assisted neighbors of a large west coast port in negotiations with port authority to secure mitigation for air quality impacts. Prepared technical comments on mobile source air quality impacts and mitigation and negotiated a $9 million CEQA mitigation package. Represented neighbors on technical advisory committee established by port to implement the air quality mitigation program. Program successfully implemented.
- Assisted construction unions in challenging permitting action for a California hazardous waste incinerator. Prepared technical comments on draft permit, assisted counsel prepare appeal of EPA permit to the Environmental Appeals Board. Participated in settlement discussions on technical issues with applicant and EPA Region 9. Case settled.
- Assisted environmental group in challenging DTSC Negative Declaration on a hazardous waste treatment facility. Prepared technical comments on risk of upset, water, and health risks. Writ of mandamus issued.
- Assisted several neighborhood associations and cities impacted by quarries, asphalt plants, and cement plants in Alameda, Shasta, Sonoma, and Mendocino counties in obtaining mitigations for dust, air quality, public health, traffic, and noise impacts from facility operations and proposed expansions.
- For over 100 industrial facilities, commercial/campus, and redevelopment projects, developed the record in preparation for CEQA and NEPA lawsuits. Prepared technical comments on hazardous materials, solid wastes, public utilities, noise, worker safety, air quality, public health, water resources, water quality, traffic, and risk of upset sections of EIRs, EISs, FONSIs, initial studies, and negative declarations. Assisted counsel in drafting petitions and briefs and prepared declarations.

- For several large commercial development projects and airports, assisted applicant and counsel prepare defensible CEQA documents, respond to comments, and identify and evaluate "all feasible" mitigation to avoid CEQA challenges. This work included developing mitigation programs to reduce traffic-related air quality impacts based on energy conservation programs, solar, low-emission vehicles, alternative fuels, exhaust treatments, and transportation management associations.

SITE INVESTIGATION/REMEDIATION/CLOSURE

- Technical manager and principal engineer for characterization, remediation, and closure of waste management units at former Colorado oil shale plant. Constituents of concern included BTEX, As, 1,1,1-TCA, and TPH. Completed groundwater monitoring programs, site assessments, work plans, and closure plans for seven process water holding ponds, a refinery sewer system, and processed shale disposal area. Managed design and construction of groundwater treatment system and removal actions and obtained clean closure.
- Principal engineer for characterization, remediation, and closure of process water ponds at a former lanthanide processing plant in Colorado. Designed and implemented groundwater monitoring program and site assessments and prepared closure plan.
- Advised the city of Sacramento on redevelopment of two former railyards. Reviewed work plans, site investigations, risk assessment, RAPS, RI/FSs, and CEQA documents. Participated in the development of mitigation strategies to protect construction and utility workers and the public during remediation, redevelopment, and use of the site, including buffer zones, subslab venting, rail berm containment structure, and an environmental oversight plan.
- Provided technical support for the investigation of a former sanitary landfill that was redeveloped as single family homes. Reviewed and/or prepared portions of numerous documents, including health risk assessments, preliminary endangerment assessments, site investigation reports, work plans, and RI/FSs. Historical research to identify historic waste disposal practices to prepare a preliminary endangerment assessment. Acquired, reviewed, and analyzed the files of 18 federal, state, and local agencies, three sets of construction field notes, analyzed 21 aerial photographs and interviewed 14 individuals associated with operation of former landfill. Assisted counsel in defending lawsuit brought by residents alleging health impacts and diminution of property value due to residual contamination. Prepared summary reports.
- Technical oversight of characterization and remediation of a nitrate plume at an explosives manufacturing facility in Lincoln, CA. Provided interface between owners and consultants. Reviewed site assessments, work plans, closure plans, and RI/FSs.

- Consultant to owner of large western molybdenum mine proposed for NPL listing. Participated in negotiations to scope out consent order and develop scope of work. Participated in studies to determine premining groundwater background to evaluate applicability of water quality standards. Served on technical committees to develop alternatives to mitigate impacts and close the facility, including resloping and grading, various thickness and types of covers, and reclamation. This work included developing and evaluating methods to control surface runoff and erosion, mitigate impacts of acid rock drainage on surface and ground waters, and stabilize nine waste rock piles containing 328 million tons of pyrite-rich, mixed volcanic waste rock (andesites, rhyolite, tuff). Evaluated stability of waste rock piles. Represented client in hearings and meetings with state and federal oversight agencies.

REGULATORY (PARTIAL LIST)

- Prepared cost analyses and comments on New York's proposed BART determinations for NOx, SO2, and PM and EPA's proposed approval of BART determinations for Danskammer Generating Station under New York Regional Haze State Implementation Plan and Federal Implementation Plan, 77 FR 51915 (August 28, 21012).
- Prepared cost analyses and comments on NOx BART determinations for Regional Haze State Implementation Plan for State of Nevada, 77 FR 23191 (April 18, 2012) and 77 FR 25660 (May 1, 2012).
- Prepared analyses of and comments on New Source Performance Standards for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 FR 22392 (April 13, 2012).
- Prepared comments on CASPR-BART emission equivalency and NOx and PM BART determinations in EPA proposed approval of State Implementation Plan for Pennsylvania Regional Haze Implementation Plan, 77 FR 3984 (January 26, 2012).
- Prepared comments and statistical analyses on hazardous air pollutants (HAPs) emission controls, monitoring, compliance methods, and the use of surrogates for acid gases, organic HAPs, and metallic HAPs for proposed National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units, 76 FR 24976 (May 3, 2011).
- Prepared cost analyses and comments on NOx BART determinations and emission reductions for proposed Federal Implementation Plan for Four Corners Power Plant, 75 FR 64221 (October 19, 2010).

- Prepared cost analyses and comments on NOx BART determinations for Colstrip Units 1- 4 for Montana State Implementation Plan and Regional Haze Federal Implementation Plan, 77 FR 23988 (April 20, 2010).
- For EPA Region 8, prepared report: Revised BART Cost Effectiveness Analysis for Tail-End Selective Catalytic Reduction at the Basin Electric Power Cooperative Leland Olds Station Unit 2 Final Report, March 2011, in support of 76 FR 58570 (Sept. 21, 2011).
- For EPA Region 6, prepared report: Revised BART Cost-Effectiveness Analysis for Selective Catalytic Reduction at the Public Service Company of New Mexico San Juan Generating Station, November 2010, in support of 76 FR 52388 (Aug. 22, 2011).
- For EPA Region 6, prepared report: Revised BART Cost-Effectiveness Analysis for Flue Gas Desulfurization at Coal-Fired Electric Generating Units in Oklahoma: Sooner Units 1 & 2, Muskogee Units 4 & 5, Northeastern Units 3 &4, October 2010, in support of 76 FR 16168 (March 26, 2011).
- Identified errors in N_2O emission factors in the Mandatory Greenhouse Gas Reporting Rule, 40 CFR 98, and prepared technical analysis to support Petition for Rulemaking to Correct Emissions Factors in the Mandatory Greenhouse Gas Reporting Rule, filed with EPA on 10/28/10.
- Assist interested parties develop input for and prepare comments on the Information Collection Request for Petroleum Refinery Sector NSPS and NESHAP Residual Risk and Technology Review, 75 FR 60107 (9/29/10).
- Technical reviewer of EPA's "Emission Estimation Protocol for Petroleum Refineries," posted for public comments on CHIEF on 12/23/09, prepared in response to the City of Houston's petition under the Data Quality Act (March 2010).
- Prepared comments on SCR cost effectiveness for EPA's Advanced Notice of Proposed Rulemaking, Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station, 74 FR 44313 (August 28, 2009).
- Prepared comments on Proposed Rule for Standards of Performance for Coal Preparation and Processing Plants, 74 FR 25304 (May 27, 2009).
- Reviewed and assisted interested parties prepare comments on proposed Kentucky air toxic regulations at 401 KAR 64:005, 64:010, 64:020, and 64:030 (June 2007).
- Prepared comments on proposed Standards of Performance for Electric Utility Steam Generating Units and Small Industrial-Commercial-Industrial Steam Generating Units, 70 FR 9706 (February 28, 2005).
- Prepared comments on Louisville Air Pollution Control District proposed Strategic Toxic Air Reduction regulations.

- Prepared comments and analysis of BAAQMD Regulation, Rule 11, Flare Monitoring at Petroleum Refineries.
- Prepared comments on Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electricity Utility Steam Generating Units (MACT standards for coal-fired power plants).
- Prepared Authority to Construct Permit for remediation of a large petroleum-contaminated site on the California Central Coast. Negotiated conditions with agencies and secured permits.
- Prepared Authority to Construct Permit for remediation of a former oil field on the California Central Coast. Participated in negotiations with agencies and secured permits.
- Prepared and/or reviewed hundreds of environmental permits, including NPDES, UIC, Stormwater, Authority to Construct, Prevention of Significant Deterioration, Nonattainment New Source Review, Title V, and RCRA, among others.
- Participated in the development of the CARB document, *Guidance for Power Plant Siting and Best Available Control Technology*, including attending public workshops and filing technical comments.
- Performed data analyses in support of adoption of emergency power restoration standards by the California Public Utilities Commission for “major” power outages, where major is an outage that simultaneously affects 10% of the customer base.
- Drafted portions of the Good Neighbor Ordinance to grant Contra Costa County greater authority over safety of local industry, particularly chemical plants and refineries.
- Participated in drafting BAAQMD Regulation 8, Rule 28, Pressure Relief Devices, including participation in public workshops, review of staff reports, draft rules and other technical materials, preparation of technical comments on staff proposals, research on availability and costs of methods to control PRV releases, and negotiations with staff.
- Participated in amending BAAQMD Regulation 8, Rule 18, Valves and Connectors, including participation in public workshops, review of staff reports, proposed rules and other supporting technical material, preparation of technical comments on staff proposals, research on availability and cost of low-leak technology, and negotiations with staff.
- Participated in amending BAAQMD Regulation 8, Rule 25, Pumps and Compressors, including participation in public workshops, review of staff reports, proposed rules, and other supporting technical material, preparation of technical comments on staff proposals, research on availability and costs of low-leak and seal-less technology, and negotiations with staff.
- Participated in amending BAAQMD Regulation 8, Rule 5, Storage of Organic Liquids, including participation in public workshops, review of staff reports, proposed rules, and other

supporting technical material, preparation of technical comments on staff proposals, research on availability and costs of controlling tank emissions, and presentation of testimony before the Board.

- Participated in amending BAAQMD Regulation 8, Rule 18, Valves and Connectors at Petroleum Refinery Complexes, including participation in public workshops, review of staff reports, proposed rules and other supporting technical material, preparation of technical comments on staff proposals, research on availability and costs of low-leak technology, and presentation of testimony before the Board.
- Participated in amending BAAQMD Regulation 8, Rule 22, Valves and Flanges at Chemical Plants, etc, including participation in public workshops, review of staff reports, proposed rules, and other supporting technical material, preparation of technical comments on staff proposals, research on availability and costs of low-leak technology, and presentation of testimony before the Board.
- Participated in amending BAAQMD Regulation 8, Rule 25, Pump and Compressor Seals, including participation in public workshops, review of staff reports, proposed rules, and other supporting technical material, preparation of technical comments on staff proposals, research on availability of low-leak technology, and presentation of testimony before the Board.
- Participated in the development of the BAAQMD Regulation 2, Rule 5, Toxics, including participation in public workshops, review of staff proposals, and preparation of technical comments.
- Participated in the development of SCAQMD Rule 1402, Control of Toxic Air Contaminants from Existing Sources, and proposed amendments to Rule 1401, New Source Review of Toxic Air Contaminants, in 1993, including review of staff proposals and preparation of technical comments on same.
- Participated in the development of the Sunnyvale Ordinance to Regulate the Storage, Use and Handling of Toxic Gas, which was designed to provide engineering controls for gases that are not otherwise regulated by the Uniform Fire Code.
- Participated in the drafting of the Statewide Water Quality Control Plans for Inland Surface Waters and Enclosed Bays and Estuaries, including participation in workshops, review of draft plans, preparation of technical comments on draft plans, and presentation of testimony before the SWRCB.
- Participated in developing Se permit effluent limitations for the five Bay Area refineries, including review of staff proposals, statistical analyses of Se effluent data, review of literature on aquatic toxicity of Se, preparation of technical comments on several staff proposals, and presentation of testimony before the Bay Area RWQCB.
- Represented the California Department of Water Resources in the 1991 Bay-Delta Hearings before the State Water Resources Control Board, presenting sworn expert testimony with

cross examination and rebuttal on a striped bass model developed by the California Department of Fish and Game.

- Represented the State Water Contractors in the 1987 Bay-Delta Hearings before the State Water Resources Control Board, presenting sworn expert testimony with cross examination and rebuttal on natural flows, historical salinity trends in San Francisco Bay, Delta outflow, and hydrodynamics of the South Bay.
- Represented interveners in the licensing of over 20 natural-gas-fired power plants and one coal gasification plant at the California Energy Commission and elsewhere. Reviewed and prepared technical comments on applications for certification, preliminary staff assessments, final staff assessments, preliminary determinations of compliance, final determinations of compliance, and prevention of significant deterioration permits in the areas of air quality, water supply, water quality, biology, public health, worker safety, transportation, site contamination, cooling systems, and hazardous materials. Presented written and oral testimony in evidentiary hearings with cross examination and rebuttal. Participated in technical workshops.
- Represented several parties in the proposed merger of San Diego Gas & Electric and Southern California Edison. Prepared independent technical analyses on health risks, air quality, and water quality. Presented written and oral testimony before the Public Utilities Commission administrative law judge with cross examination and rebuttal.
- Represented a PRP in negotiations with local health and other agencies to establish impact of subsurface contamination on overlying residential properties. Reviewed health studies prepared by agency consultants and worked with agencies and their consultants to evaluate health risks.

WATER QUALITY/RESOURCES

- Directed and participated in research on environmental impacts of energy development in the Colorado River Basin, including contamination of surface and subsurface waters and modeling of flow and chemical transport through fractured aquifers.
- Played a major role in Northern California water resource planning studies since the early 1970s. Prepared portions of the Basin Plans for the Sacramento, San Joaquin, and Delta basins including sections on water supply, water quality, beneficial uses, waste load allocation, and agricultural drainage. Developed water quality models for the Sacramento and San Joaquin Rivers.
- Conducted hundreds of studies over the past 40 years on Delta water supplies and the impacts of exports from the Delta on water quality and biological resources of the Central Valley, Sacramento-San Joaquin Delta, and San Francisco Bay. Typical examples include:

1. Evaluate historical trends in salinity, temperature, and flow in San Francisco Bay and upstream rivers to determine impacts of water exports on the estuary;
2. Evaluate the role of exports and natural factors on the food web by exploring the relationship between salinity and primary productivity in San Francisco Bay, upstream rivers, and ocean;
3. Evaluate the effects of exports, other in-Delta, and upstream factors on the abundance of salmon and striped bass;
4. Review and critique agency fishery models that link water exports with the abundance of striped bass and salmon;
5. Develop a model based on GLMs to estimate the relative impact of exports, water facility operating variables, tidal phase, salinity, temperature, and other variables on the survival of salmon smolts as they migrate through the Delta;
6. Reconstruct the natural hydrology of the Central Valley using water balances, vegetation mapping, reservoir operation models to simulate flood basins, precipitation records, tree ring research, and historical research;
7. Evaluate the relationship between biological indicators of estuary health and down-estuary position of a salinity surrogate (X2);
8. Use real-time fisheries monitoring data to quantify impact of exports on fish migration;
9. Refine/develop statistical theory of autocorrelation and use to assess strength of relationships between biological and flow variables;
10. Collect, compile, and analyze water quality and toxicity data for surface waters in the Central Valley to assess the role of water quality in fishery declines;
11. Assess mitigation measures, including habitat restoration and changes in water project operation, to minimize fishery impacts;
12. Evaluate the impact of unscreened agricultural water diversions on abundance of larval fish;
13. Prepare and present testimony on the impacts of water resources development on Bay hydrodynamics, salinity, and temperature in water rights hearings;
14. Evaluate the impact of boat wakes on shallow water habitat, including interpretation of historical aerial photographs;
15. Evaluate the hydrodynamic and water quality impacts of converting Delta islands into reservoirs;

16. Use a hydrodynamic model to simulate the distribution of larval fish in a tidally influenced estuary;
17. Identify and evaluate non-export factors that may have contributed to fishery declines, including predation, shifts in oceanic conditions, aquatic toxicity from pesticides and mining wastes, salinity intrusion from channel dredging, loss of riparian and marsh habitat, sedimentation from upstream land alternations, and changes in dissolved oxygen, flow, and temperature below dams.

- Developed, directed, and participated in a broad-based research program on environmental issues and control technology for energy industries including petroleum, oil shale, coal mining, and coal slurry transport. Research included evaluation of air and water pollution, development of novel, low-cost technology to treat and dispose of wastes, and development and application of geohydrologic models to evaluate subsurface contamination from in-situ retorting. The program consisted of government and industry contracts and employed 45 technical and administrative personnel.
- Coordinated an industry task force established to investigate the occurrence, causes, and solutions for corrosion/erosion and mechanical/engineering failures in the waterside systems (e.g., condensers, steam generation equipment) of power plants. Corrosion/erosion failures caused by water and steam contamination that were investigated included waterside corrosion caused by poor microbiological treatment of cooling water, steam-side corrosion caused by ammonia-oxygen attack of copper alloys, stress-corrosion cracking of copper alloys in the air cooling sections of condensers, tube sheet leaks, oxygen in-leakage through condensers, volatilization of silica in boilers and carry over and deposition on turbine blades, and iron corrosion on boiler tube walls. Mechanical/engineering failures investigated included: steam impingement attack on the steam side of condenser tubes, tube-to-tube-sheet joint leakage, flow-induced vibration, structural design problems, and mechanical failures due to stresses induced by shutdown, startup and cycling duty, among others. Worked with electric utility plant owners/operators, condenser and boiler vendors, and architect/engineers to collect data to document the occurrence of and causes for these problems, prepared reports summarizing the investigations, and presented the results and participated on a committee of industry experts tasked with identifying solutions to prevent condenser failures.
- Evaluated the cost effectiveness and technical feasibility of using dry cooling and parallel dry-wet cooling to reduce water demands of several large natural-gas fired power plants in California and Arizona.
- Designed and prepared cost estimates for several dry cooling systems (e.g., fin fan heat exchangers) used in chemical plants and refineries.
- Designed, evaluated, and costed several zero liquid discharge systems for power plants.

- Evaluated the impact of agricultural and mining practices on surface water quality of Central Valley steams. Represented municipal water agencies on several federal and state advisory committees tasked with gathering and assessing relevant technical information, developing work plans, and providing oversight of technical work to investigate toxicity issues in the watershed.

AIR QUALITY/PUBLIC HEALTH

- Prepared or reviewed the air quality and public health sections of hundreds of EIRs and EISs on a wide range of industrial, commercial and residential projects.
- Prepared or reviewed hundreds of NSR and PSD permits for a wide range of industrial facilities.
- Designed, implemented, and directed a 2-year-long community air quality monitoring program to assure that residents downwind of a petroleum-contaminated site were not impacted during remediation of petroleum-contaminated soils. The program included real-time monitoring of particulates, diesel exhaust, and BTEX and time integrated monitoring for over 100 chemicals.
- Designed, implemented, and directed a 5-year long source, industrial hygiene, and ambient monitoring program to characterize air emissions, employee exposure, and downwind environmental impacts of a first-generation shale oil plant. The program included stack monitoring of heaters, boilers, incinerators, sulfur recovery units, rock crushers, API separator vents, and wastewater pond fugitives for arsenic, cadmium, chlorine, chromium, mercury, 15 organic indicators (e.g., quinoline, pyrrole, benzo(a)pyrene, thiophene, benzene), sulfur gases, hydrogen cyanide, and ammonia. In many cases, new methods had to be developed or existing methods modified to accommodate the complex matrices of shale plant gases.
- Conducted investigations on the impact of diesel exhaust from truck traffic from a wide range of facilities including mines, large retail centers, light industrial uses, and sports facilities. Conducted traffic surveys, continuously monitored diesel exhaust using an aethalometer, and prepared health risk assessments using resulting data.
- Conducted indoor air quality investigations to assess exposure to natural gas leaks, pesticides, molds and fungi, soil gas from subsurface contamination, and outgasing of carpets, drapes, furniture and construction materials. Prepared health risk assessments using collected data.
- Prepared health risk assessments, emission inventories, air quality analyses, and assisted in the permitting of over 70 1 to 2 MW emergency diesel generators.
- Prepare over 100 health risk assessments, endangerment assessments, and other health-based studies for a wide range of industrial facilities.

- Developed methods to monitor trace elements in gas streams, including a continuous real-time monitor based on the Zeeman atomic absorption spectrometer, to continuously measure mercury and other elements.
- Performed nuisance investigations (odor, noise, dust, smoke, indoor air quality, soil contamination) for businesses, industrial facilities, and residences located proximate to and downwind of pollution sources.

PUBLICATIONS AND PRESENTATIONS (Partial List - Representative Publications)

J.P. Fox, T.P. Rose, and T.L. Sawyer, Isotope Hydrology of a Spring-fed Waterfall in Fractured Volcanic Rock, 2007.

C.E. Lambert, E.D. Winegar, and Phyllis Fox, Ambient and Human Sources of Hydrogen Sulfide: An Explosive Topic, Air & Waste Management Association, June 2000, Salt Lake City, UT.

San Luis Obispo County Air Pollution Control District and San Luis Obispo County Public Health Department, *Community Monitoring Program*, February 8, 1999.

The Bay Institute, *From the Sierra to the Sea. The Ecological History of the San Francisco Bay-Delta Watershed*, 1998.

J. Phyllis Fox, *Well Interference Effects of HDPP's Proposed Wellfield in the Victor Valley Water District*, Prepared for the California Unions for Reliable Energy (CURE), October 12, 1998.

J. Phyllis Fox, *Air Quality Impacts of Using CPVC Pipe in Indoor Residential Potable Water Systems*, Report Prepared for California Pipe Trades Council, California Firefighters Association, and other trade associations, August 29, 1998.

J. Phyllis Fox and others, *Authority to Construct Avila Beach Remediation Project*, Prepared for Unocal Corporation and submitted to San Luis Obispo Air Pollution Control District, June 1998.

J. Phyllis Fox and others, *Authority to Construct Former Guadalupe Oil Field Remediation Project*, Prepared for Unocal Corporation and submitted to San Luis Obispo Air Pollution Control District, May 1998.

J. Phyllis Fox and Robert Sears, *Health Risk Assessment for the Metropolitan Oakland International Airport Proposed Airport Development Program*, Prepared for Plumbers & Steamfitters U.A. Local 342, December 15, 1997.

Levine-Fricke-Recon (Phyllis Fox and others), *Preliminary Endangerment Assessment Work Plan for the Study Area Operable Unit, Former Solano County Sanitary Landfill, Benicia, California*, Prepared for Granite Management Co. for submittal to DTSC, September 26, 1997.

Phyllis Fox and Jeff Miller, "Fathead Minnow Mortality in the Sacramento River," *IEP Newsletter*, v. 9, n. 3, 1996.

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Phyllis Fox and Elaine Archibald, *Aquatic Toxicity and Pesticides in Surface Waters of the Central Valley*, California Urban Water Agencies (CUWA) Report, September 1997.

Phyllis Fox and Alison Britton, *Evaluation of the Relationship Between Biological Indicators and the Position of X2*, CUWA Report, 1994.

Phyllis Fox and Alison Britton, *Predictive Ability of the Striped Bass Model*, WRINT DWR-206, 1992.

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Phyllis Fox, *Trip 2 Report, Environmental Monitoring Plan, Parachute Creek Shale Oil Program*, Unocal Report, 1991.

J. P. Fox and others, "Long-Term Annual and Seasonal Trends in Surface Salinity of San Francisco Bay," *Journal of Hydrology*, v. 122, p. 93-117, 1991.

J. P. Fox and others, "Reply to Discussion by D.R. Helsel and E.D. Andrews on Trends in Freshwater Inflow to San Francisco Bay from the Sacramento-San Joaquin Delta," *Water Resources Bulletin*, v. 27, no. 2, 1991.

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J. P. Fox, "Water Development Increases Freshwater Flow to San Francisco Bay," *SCWC Update*, v. 4, no. 2, 1988.

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J. P. Fox, "El Mercurio en el Medio Ambiente: Aspectos Referentes al Peru," (Mercury in the Environment: Factors Relevant to Peru) Proceedings of Simposio Los Pesticidas y el Medio Ambiente," ONERN-CONCYTEC, Lima, Peru, April 25-27, 1984. (Also presented at Instituto Tecnologico Pesquero and Instituto del Mar del Peru.)

J. P. Fox, "Mercury, Fish, and the Peruvian Diet," *Boletin de Investigacion*, Instituto Tecnologico Pesquero, Lima, Peru, v. 2, no. 1, pp. 97-116, l984.

J. P. Fox, P. Persoff, A. Newton, and R. N. Heistand, "The Mobility of Organic Compounds in a Codisposal System," *Proceedings of the Seventeenth Oil Shale Symposium*, Colorado School of Mines Press, Golden, CO, 1984.

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M. Goldstein et al., *High Level Nuclear Waste Standards Analysis, Regulatory Framework Comparison*, Battelle Memorial Institute Report No. BPMD/82/E515-06600/3, Sept. 1982.

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A. T. Hodgson, M. J. Pollard, G. J. Harris, D. C. Girvin, J. P. Fox, and N. J. Brown, *Mercury Mass Distribution During Laboratory and Simulated In-Situ Retorting*, Lawrence Berkeley Laboratory Report LBL-12908, 39 pp., Feb. 1982.

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Exhibit B to Fox Report

Exhibit B - Eight-hour Ozone Standard Attainment Status of Refineries With Direct or Indirect Connections to Keystone XL

Refinery	Location	8-hour ozone (1997) nonattainment, if any*	8-hour ozone (2008) nonattainment, if any**
Gulf Coast Refineries With Direct Pipeline Access To The Proposed Project			
Motiva Enterprises, LLC	Port Arthur, TX	n/a	n/a
Total Petrochemicals	Port Arthur, TX	n/a	n/a
Premcor Refining Group	Port Arthur, TX	n/a	n/a
Exxon Mobil	Beaumont, TX	n/a	n/a
Pasadena Refining	Pasadena, TX	Severe 15	Marginal
Houston Refining	Houston, TX	Severe 15	Marginal
Valero Energy Corp.	Houston, TX	Severe 15	Marginal
Deer Park Refining	Deer Park, TX	Severe 15	Marginal
Exxon Mobil	Baytown, TX	Severe 15	Marginal
BP	Texas City, TX	Severe 15	Marginal
Marathon Petroleum Co.	Texas City, TX	Severe 15	Marginal
Valero Energy Corp.	Texas City, TX	Severe 15	Marginal
Calcasieu Refining	Lake Charles, LA	n/a	n/a
CITGO	Lake Charles, LA	n/a	n/a
ConocoPhillips	Lake Charles/Westlake, LA	n/a	n/a
Gulf Coast Refineries In PADD 3 Without Direct Pipeline Access To The Proposed Project			
Hunt Refining Co.	Tuscaloosa, AL	n/a	n/a
Shell Chemical	Saraland, AL	n/a	n/a
ConocoPhillips	Belle Chasse, LA	n/a	n/a
Exxon Mobil	Baton Rouge, LA	n/a	Marginal
Alon Refining	Krotz Springs, LA	n/a	n/a
Valero Energy Corp.	St. Charles/Norco, LA	n/a	n/a
Marathon Petroleum	Garyville, LA	n/a	n/a
Chalmette Refining	Chalmette, LA	n/a	n/a
Valero Energy Corp.	Meraux, LA	n/a	n/a
Motiva Enterprises LLC	Norco, LA	n/a	n/a
Motiva Enterprises LLC	Convent, LA	n/a	n/a
Placid Refining	Port Allen, LA	n/a	Marginal
Shell Chemical	Saint Rose, LA	n/a	n/a
ChevronTexaco	Pascagoula, MS	n/a	n/a

Refinery	Location	8-hour ozone (1997) nonattainment, if any*	8-hour ozone (2008) nonattainment, if any**
Gulf Coast Refineries In PADD 3 Without Direct Pipeline Access To The Proposed Project (cont.)			
ConocoPhillips	Sweeny, TX	Severe 15	Marginal
CITGO	Corpus Christi, TX	n/a	n/a
Valero Energy Corp.	Three Rivers, TX	n/a	n/a
Flint Hills Resources	Corpus Christi, TX	n/a	n/a
Valero Energy Corp.	Corpus Christi, TX	n/a	n/a
Inland PADD 3 Refineries With Possible Pipeline Connection To The Proposed Project			
Navajo Refining	Artesia, NM	n/a	n/a
WRB Refining	Borger, TX	n/a	n/a
Valero Energy Corp.	Sunray/McKee, TX	n/a	n/a
AlonUSA	Big Spring, TX	n/a	n/a
Delek	Tyler, TX	n/a	n/a
Inland PADD 3 Refineries Without Pipeline Access To The Proposed Project			
No refineries specified			

Sources: U.S. Dept. of State, Keystone XL Project Draft Supplemental Environmental Impact Report (March 2013), Table 4.15-18; U.S. EPA, The Green Book Nonattainment Areas for Criteria Pollutants, http://www.epa.gov/oaqps001/greenbk/ (accessed April 12, 2013).

*Key for severity of 8-hr ozone nonattainment - 1997 standard:

Severe 17
Severe 15
Serious
Moderate
Marginal

**Key for severity of 8-hr ozone nonattainment - 2008 standard:

Extreme
Severe 15
Serious
Moderate
Marginal

Exhibit C to Fox Report

Exhibit C: Verifications of Emissions Estimates									
	MOTIVA (DSEIS p 4.15-77)		**HYPERION** (DSEIS p 4.15-77)		**PROJECT** (calculated by scaling up Motiva and Hyperion emissions)			**DSEIS ESTIMATE** (DSEIS p 4.15-78)	
BPD	325,000		400,000		830,000			830,000	
					Motiva	**Hyperion**		**Motiva**	**Hyperion**
	ton/yr		ton/yr		ton/yr	ton/yr		ton/yr	ton/yr
NOx	592.74		687		1,514	1,426		1,514	1,604
CO	1489.53		810		3,804	1,681		3,804	4,148
VOC	-116.73		536		-298	1,112			1,718
SO2	1679.73		183		4,290	380		4,290	1,791
PM	464.37		1035		1,186	2,148		1,186	2,170