Crystal Orr

From: Tonia Moro [tonia@toniamoro.com]
Sent: Tuesday, July 09, 2019 7:36 AM
To: Planning Department
Cc: mccaffrees@frontier.com
Subject: REM 19-001 surrebuttal comments
Attachments: Hearing_Memo_Rebuttal_REM 19-001.f.pdf

Greetings,

Please file the attached comments into the record as Rogue Climate and Jody McCaffree's surrebuttal. A hard copy will follow.

Tonia L. Moro
Attorney at Law PC

19 S. Orange Street
Medford Oregon 97501
541 973 2063

Exhibit: 52
Date: 7/9/19

Tonia L. Moro
Attorney at Law P.C.
19 S. Orange Street
Medford, Oregon 97501
541 973 2063
Tonia@ToniaMoro.com

**BEFORE COOS COUNTY PLANNING DEPARTMENT
HEARINGS OFFICER**

In the Matter of the on remand from the Land Use Board of Appeals in *Oregon Shores Conservation Coalition v. Coos County*, 76 OR LUBA 346 (2017	REM-19-001 Sur-rebuttal Statement

On behalf of Rogue Climate and Jody McCaffree (opponents), I submit the following additional documents which rebut the information the applicant submitted in its document dump on June 24, 2019. These documents further make the undeniable case that there is no public need for this project or the dredging and fill proposed. They speak for themselves.

1. McCullough Research "Natural Gas Supplies for the Proposed Jordan Cove LNG Terminal."

2. Rachel Wilson, "Foreign or Domestic? The souce of the natural gas that will be processed at the proposed Jordan Cove LNG facility."

3. Summaries of U.S. Natural Gas Supply Demand and Price Forecasts.

4. T. Nace, L. Plante, and J. Browning for Global Energy Monitor, "The New Gas Boom; Tracking Global LNG Infastructure."

5. T. Nace, L. Plante, and J. Browning for Global Energy Monitor, "Pipeline Bubble; North America is Betting over $1 Trillion on Risky Fossil Infrastructure Boom."

6. Whitelaw, Principal Investigator, Testifying Economist, Founder FION LLC, "Public Comments from Ed Whitelaw on the Jordan Cove Energy Project ... to .. the FERC Commission."

/ / /

7. Engineers for a Sustainable Future, "Trade Study, Coos Bay Floating Offshore Wind vs. LNG Export."

/s/ Tonia Moro
Tonia Moro
Attorney for Opponents

MCCULLOUGH RESEARCH

ROBERT F. MCCULLOUGH, JR.
PRINCIPAL

Natural Gas Supplies for the Proposed Jordan Cove LNG Terminal

Robert McCullough
McCullough Research
July 3, 2019

Both documentary evidence and economic theory indicate that natural gas exported from the proposed LNG terminal at Coos Bay will be sourced from British Columbia and Alberta.

Jordan Cove has been an active project since 2006. For its first five years, the project then owned by Fort Chicago and Energy Projects Development was an LNG import facility. As LNG prices rose, Jordan Cove refiled with FERC as an LNG Export facility. Ownership of the project has evolved over time as Fort Chicago changed into Veresen. In 2017, Veresen was acquired by Pembina.

On February 20, 2014, Dan Althoff, the CEO of Veresen, Jordan Cove's corporate parent, was quoted in an article describing the basic structure of supplies to Jordan Cove:

> It provides a bit of diversity to exports. It's the first [U.S.] West Coast facility to be reviewed. It exports Canadian gas, which is pretty positively received in Washington. Some of the petrochemicals industry's concerns and complaints about the Gulf Coast facilities aren't shared on this project, because Jordan Cove pulls gas off existing Canadian infrastructure, from existing fields and pipelines.[1]

Following up Jordan Cove's prospects, Althoff later stated that:

> There are some synergies [between the field and the LNG terminal], because the buyers we're talking to need to find gas and we know where a

[1] How Oregon LNG facilities could be key to exporting Canadian gas to Asia, Yadullah Hussain, Financial Post, February 20, 2014.

> lot of it is," Mr. Althoff said. "We'll connect the dots and we'll support our buyers and we'll support our partners."[2]

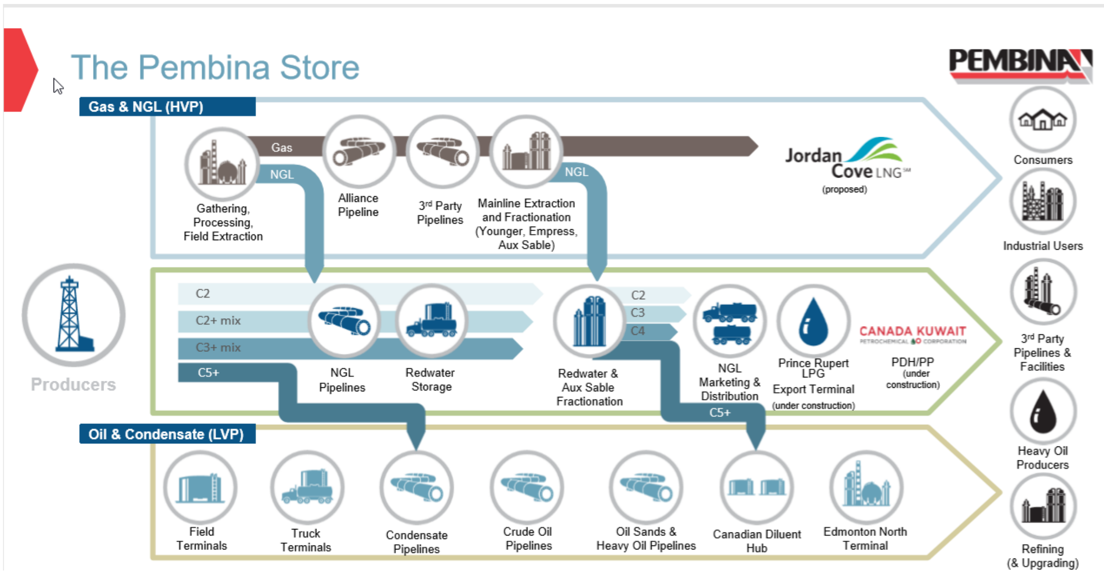
In 2017, Veresen was acquired by Pembina, also based in Alberta. Mick Dilger, Pembina's CEO made clear where Jordan Cove's gas would be coming from:

> Dilger believes Jordan Cove has a higher chance of success under Pembina than it had under Veresen because it has the money to finance it, the expertise to build both the plant and a 400-kilometre pipeline through tough terrain, and the relationships with Western Canadian producers and Asian customers to make it viable.
>
> Some day, Pembina would like to build an LNG facility on the B.C. coast, too, Dilger said, but Jordan Cove has key advantages: it is cheaper to build a pipeline to receive Western Canadian gas from existing networks than build over the Canadian Rockies; its location near larger population centres means there is labour available to build it; and shorter travel time to Asian markets versus the U.S. Gulf Coast means lower transportation costs for its LNG.[3]

Jordan Cove is planned for Coos Bay, Oregon. In order to procure natural gas, a pipeline is planned to connect to supplies at Malin, Oregon. Malin, Oregon connects to Kingsgate, Alberta and Opal, Wyoming. Overall, Coos Bay is over 909 miles from sources of supply in the east and 841 miles from Alberta.[4]

Pembina's financial presentations also indicate that Canada is the primary source of supply since Pembina does not own gathering, processing, or field extraction assets elsewhere:

[2] With Montney assets buy, Veresen eyes building first West Coast LNG facility in Oregon, Geoffrey Morgan, Financial Post, December 23, 2014.
[3] Pembina Pipeline's new purpose: Get Canada's oil and gas to the rest of the world, Claudia Cataneo, Financial Post, February 20, 2018.
[4] The Pacific Connector Gas Pipeline is 229 miles from the Malin hub. The northern terminus of the GTN pipeline is 612 miles away at Kingsgate, Alberta. The eastern terminus of the Ruby pipeline is 680 miles away.



[5]

In the diagram above, taken from a presentation this month to investors, Pembina directly aligns its Jordan Cove investments with their Canadian infrastructure. It is worth noting that the Ruby pipeline, connecting Colorado with the Malin natural gas trading hub, is not mentioned.

I. Background

On September 4, 2007, Jordan Cove LNG was proposed as an import terminal – primarily oriented to meeting domestic U.S. needs from imported natural gas.[6] The Coos Bay location and proposed interconnection to existing natural gas pipelines at Malin, Oregon was as appropriate then as it is inappropriate today. As a general rule, positioning an import terminal near potential loads is a good idea. Positioning an export terminal far from natural gas supplies is a significant disadvantage.

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[5] Pembina Pipeline Corporation Corporate Update, June 2019, page 7.
[6] Pacific Connector Gas Pipeline, LP (Docket Nos. CP07-441-000, CP07-442-000, and CP07-443-000) and Jordan Cove Energy Project, L.P. (Docket No. CP07-444-000); Notice of Application for Certificate of Public Convenience and Necessity and Section 3 Authorization, September 19, 2007.

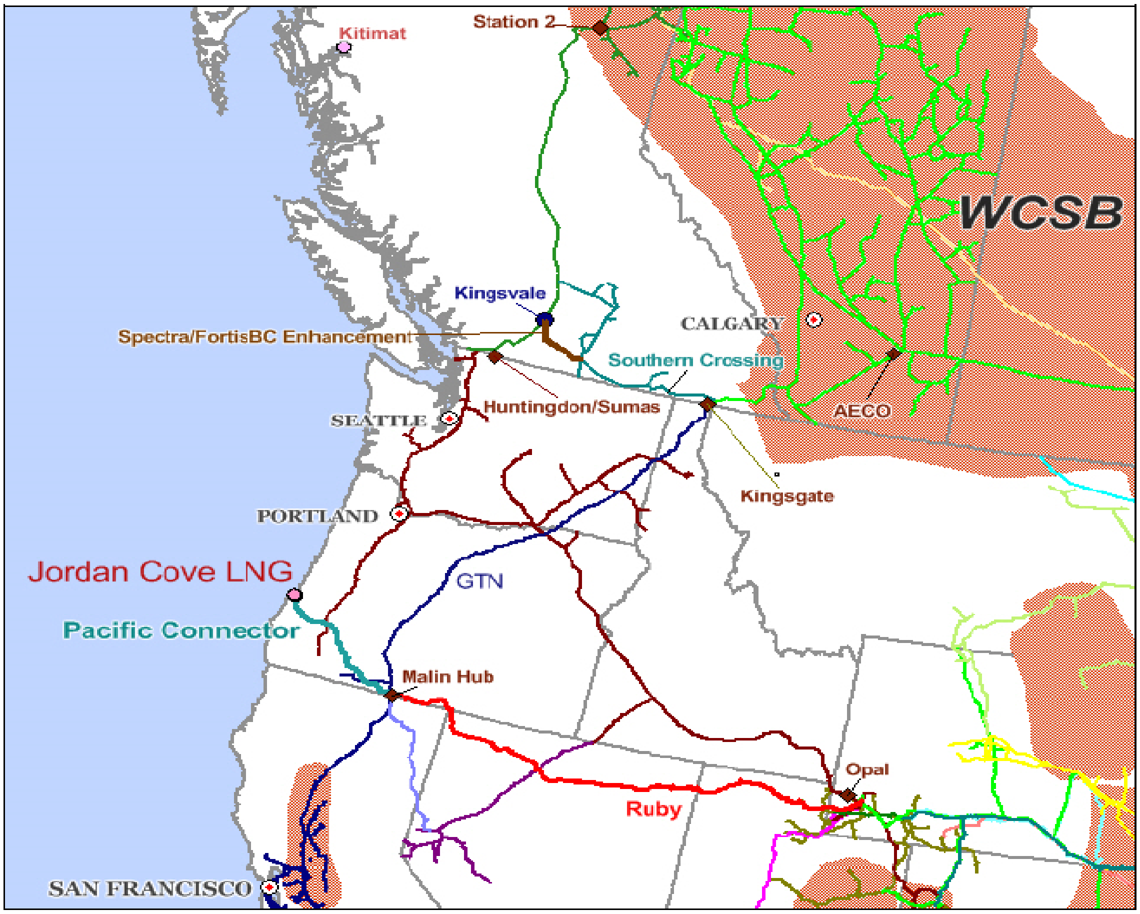

Figure 1: Existing Western North America Pipelines – with Jordan Cove and Pacific Connector[7]

Historically, California natural gas prices are significantly higher than those in Alberta and the Pacific Northwest.[8]

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[7] IN THE MATTER OF the National Energy Board Act, RSC 1985, c N-7, as amended; AND IN THE MATTER OF an application by Jordan Cove LNG L.P. for a licence pursuant to section 117 of the National Energy Board Act authorizing the export of gas, September 9, 2013, Appendix A, page 2.

[8] See, for example, Power Market Price Study and Documentation BP-18-FS-BPA-04, July 2017, page 33.

When Pacific natural gas prices were lower than those in the United States, importing LNG at Coos Bay and selling the natural gas into the lucrative California market made economic sense.

This situation did not endure for long. Over the last decade two factors changed the market dramatically:

1. On March 11, 2011, a tidal wave destroyed the nuclear plant at Fukushima Daiichi. Japanese authorities subsequently closed Japan's nuclear fleet and prices spiked dramatically.
2. Technological innovations in the U.S. and Canada revolutionized oil and natural gas production leading to an increasing surplus in North American markets.

Landed LNG prices in Japan, Korea, and China are published daily in the Platts LNG Daily. They are referred to as the JKM index. The major North American trading hub

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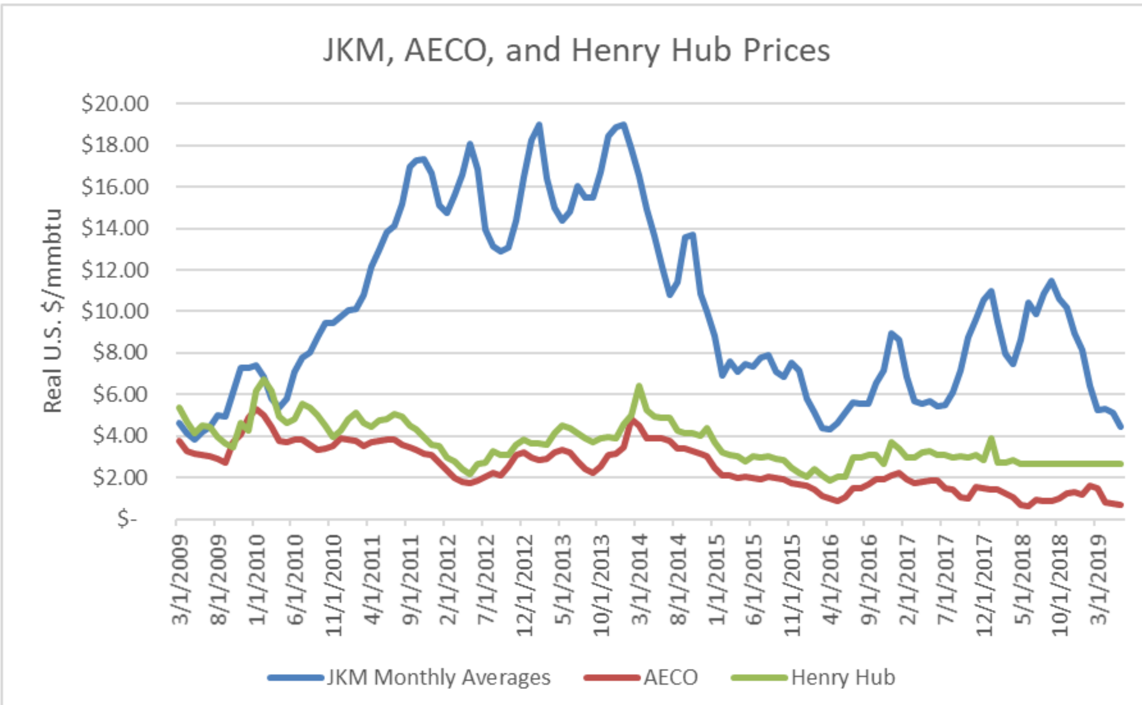
Table 1: Cash Prices at Henry Hub and Basis Differentials (nominal $/MMBtu)

	FY 2018	FY 2019
Henry	3.12	3.00
AECO	-0.89	-0.82
Kingsgate	-0.42	-0.45
Malin	-0.24	-0.24
Opal	-0.31	-0.31
PG&E	0.23	0.23
SoCal City	0.02	0.03
Ehrenberg	-0.15	-0.14
Topock	-0.15	-0.14
San Juan	-0.34	-0.32
Stanfield	-0.32	-0.32
Sumas	-0.41	-0.41

AECO prices are lower than those at Henry Hub in Louisiana – averaging a discount from Henry Hub of $.82/MMBtu.

for natural gas is Henry Hub in Louisiana. Wholesale natural gas prices in Alberta are referred to by the acronym "AECO".

Landed prices in Asia rapidly diverged from those in Alberta and the United States. The following chart shows the dramatic rise in Asian natural gas prices after the Fukushima accident (blue line) and the steady fall in North American natural gas prices in Alberta (red line) and Louisiana (green line):



The prospect of competing with Asian markets for scarce Pacific Rim LNG spelled the end of Jordan Cove's prospects as an LNG importer.

The massive differential between JKM and AECO prices spawned over twenty LNG export terminal proposals – primarily in British Columbia. Two proposals were based in Oregon – one in Astoria and one in Coos Bay.

Japan has gradually restarted its nuclear fleet and other suppliers have stepped in to supply the Pacific Rim. Not surprisingly, JKM prices are falling dramatically with prices today less than half their levels one year ago. At least five of the proposed LNG projects in

British Columbia have cancelled their plans to build LNG export terminals in the province.[9]

At today's JKM price, none of the West Coast LNG export terminals are attractive investments. Only one project, LNG Canada, has received a "Final Investment Decision" and started construction. The economics of Jordan Cove are highly problematic given its high costs and the declining Asian Prices.

On July 2, 2019, the JKM index was $4.625/MMBtu.[10] The breakeven price (the price at which the project would earn zero profits and merely recover its costs) for Jordan Cove is $4.27/MMBtu.[11] The natural gas price at the Malin hub is $1.99/MMBtu.[12] When the cost of transportation to Japan is added in, the cost of Jordan Cove LNG is $7.13/MMBtu. If today's prices would prevail into the future, Jordan Cove would lose $2.50 for every MMBtu shipped.

Scarcity of natural gas pipeline capacity from Alberta has increased the basis differential between Henry Hub and AECO.[13] To the degree that the source and transportation of an LNG export are packaged by Jordan Cove, there is an incentive to access the relatively inexpensive natural gas in Western Canada rather than natural gas from the U.S.

II. Market Hubs and the Structure of Transactions

Natural gas and electricity transactions are commonly organized by hubs – locations where buyers and sellers can make spot and forward purchases. Malin, Oregon is a market hub for both electricity and natural gas. Its development as a hub was largely based on resource and consumption differentials between the Pacific Northwest and California.

The Pacific Northwest is winter peaking, since heating loads tend to occur in cold months. California is a summer peaking region. This difference makes Malin a good location for trading between different buyers and sellers.

[9] Sightline Institute. January 2018. https://www.sightline.org/research_item/maps-british-columbia-lng-proposals/
[10] Platts LNG Daily, July 2, 2019, page 1.
[11] "The Questionable Economics of Jordan Cove LNG Terminal," McCullough Research, June 5, 2019, page 4. http://www.mresearch.com/wp-content/uploads/20190605-Jordan-Cove.pdf
[12] "Easing Heat, Stout Supplies Pressure July NatGas Bidweek Prices; Futures Remain Near Lows," NGI All News Access, July 1, 2019. https://www.naturalgasintel.com/articles/118844-easing-heat-stout-supplies-pressure-july-natgas-bidweek-prices-futures-remain-near-lows
[13] 'Basis differential' is defined as the expected price difference between two hubs.

Unlike larger national gas hubs, Malin has no forward markets traded at the major commodity exchanges. When a forward exchange is absent, long-term transactions must be made with an individual counterparty. This is generally more expensive and less likely to close since the number of counterparties may be quite limited. In language of traders, long-term transactions at the Malin natural gas hub will be over the counter.[14] Price discovery in the absence of forward markets can also be challenging in the same way that buying or selling a vintage car in a small town might be both challenging and poses the risk of paying the wrong price. Generally, such transactions tend to be more successful if you drive to a larger city with more car dealers.

In this case, it means that longer-term transactions will tend to occur at the source of the natural gas where markets are more liquid and there are more counterparties. In this case, the most liquid market for longer-term transactions is AECO in Alberta. Not only are prices generally lower in Alberta than in the Western U.S., Alberta's market is growing very rapidly with recent natural gas discoveries along the Alberta/British Columbia border.

One of the attributes of a market hub is that short term transactions take place at the going price. Regardless of the source the short-term price is the same. Malin's prices tend to reflect the higher prices found in California. As noted above, the decision to connect at Malin was a good choice when the Jordan Cove project was intended to import natural gas for sale to California. The current export proposal is at a disadvantage compared to British Columbia export terminals with a shorter path to low-priced Alberta natural gas.

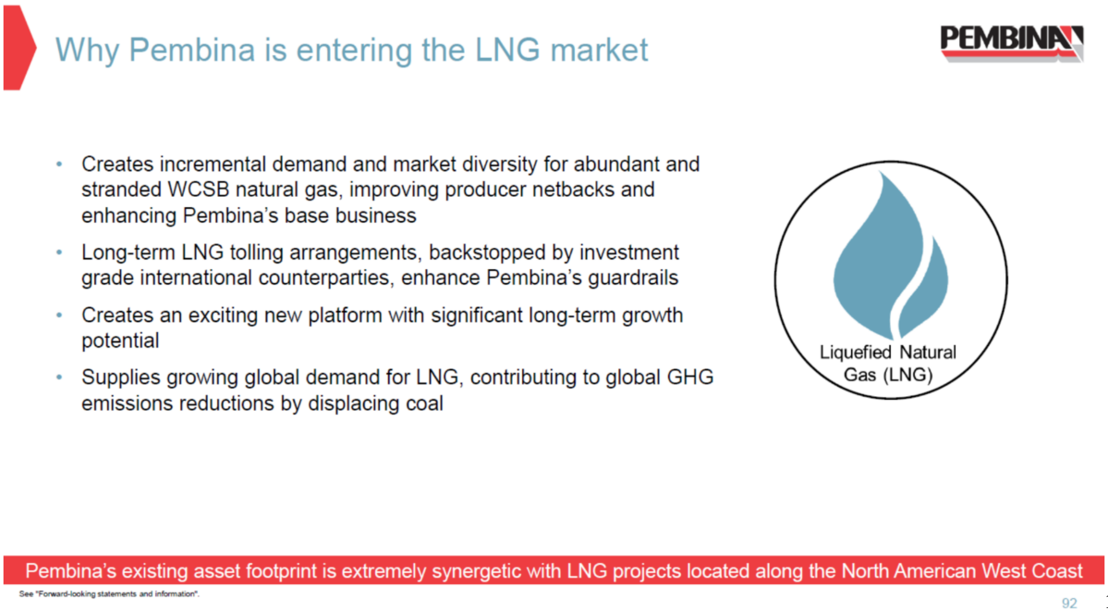
Jordan Cove has frequently referred to its "tolling model," although their presentations often lack precision.[15] In tolling arrangements, the purchaser buys the gas, arranges delivery to the LNG facility, and is responsible for the shipping of the LNG; in theory, Jordan Cove would not be responsible for anything except converting the gas to LNG at their facility. In contrast, the most successful U.S. exporter, Cheniere, offers complete transactions in LNG at their dock. Purchasers do not need to handle natural gas purchasing or transportation issues in the United States.

From Jordan Cove's investor briefings and regulatory filings, it seems very likely that they will be arranging supplies and transportation in fashion similar to Cheniere.

For example, a recent presentation by Jordan Cove states:

[14] 'Over the counter' is a standard term in commodity trading that means that transactions are negotiated directly between counterparties. As a general rule, over the counter transactions are less liquid than those occurring at exchanges like the Chicago Mercantile Exchange or ICE.

[15] See, for example, the discussion of a tolling model for exporters of LNG produced in the USA: LNG Export USA 2014, Guy Dayvault, Veresen, April 30, 2014.



[16,17]

Absent long-term transactions based on Albertan sources, Jordan Cove would not have needed to procure an export license from the Canadian National Energy Board or either an import or export license from the U.S. Office of Fossil Energy. (See section IV, below.) The issue was addressed in Jordan Cove's application for an export license at the NEB. Jordan Cove asked the NEB to exempt them from the standard export reporting requirements. The Board rejected their request:

> The Board has decided to deny Jordan Cove LNG's request for exemption from the Reporting Regulations. The Applicant referred to the competitive disadvantage Jordan Cove LNG would be placed in if other LNG export licence holders were exempted from the reporting requirements with which Jordan Cove LNG is required to comply.
>
> The Board notes that under the Reporting Regulations, Jordan Cove LNG would be reporting exports by pipeline to the U.S., and not LNG exports from the proposed liquefaction facility in Oregon. Reporting on pipeline exports to the U.S. is a well-established practice in which the Reporting Regulations apply to all exporters in a similar manner. The Board reminds Jordan Cove LNG, in any instance where it is acting as an agent, that it is

[16] Pembina Pipeline Company Investor Day. May 14, 2019, page 92.
[17] WCSB stands for the Western Canadian Sedimentary Basin. The WCSB covers eastern British Columbia and almost all of Alberta and Saskatchewan.

> responsible, as the licence holder, for reporting the information prescribed by the Reporting Regulations.[18]

It is clear that Jordan Cove was pursuing a more extensive role than the minimal tolling process described above – it is either exporting Canadian gas it has purchased or, at a minimum, is acting as agent for the purchase of Canadian gas. Moreover, if Jordan Cove was simply helping customers, there would have been little reason to ask for a blanket release from the universal reporting requirements that other exporters must follow.

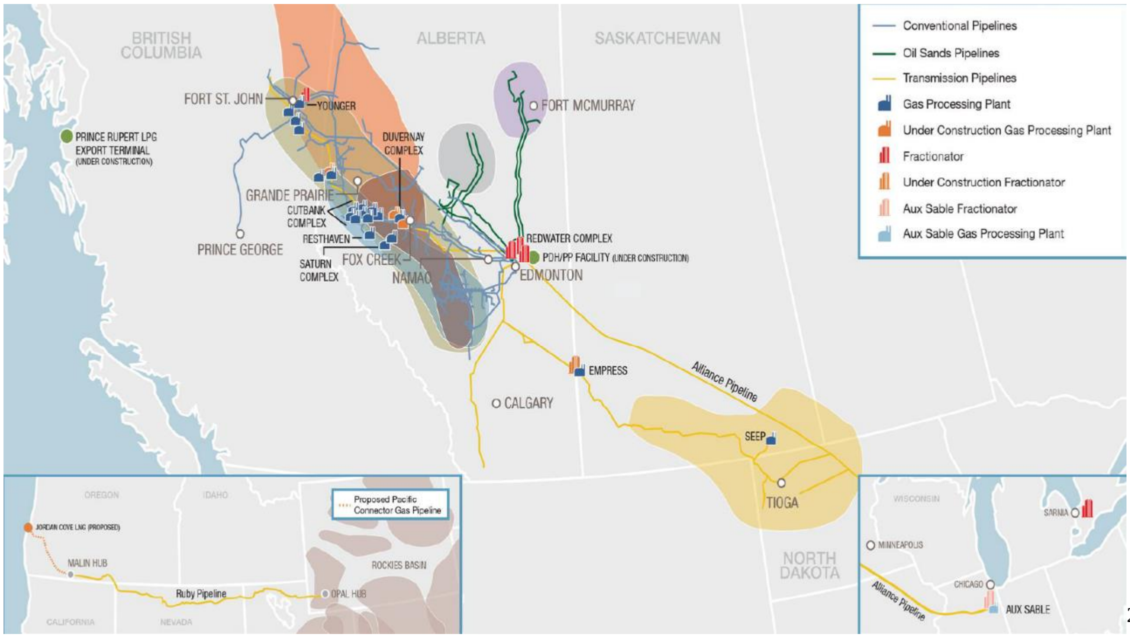
III. Vertical Integration

The Asian markets for North American LNG look highly competitive and volatile. With the first six months of 2019 prices averaging only $5.90/MMBtu, few projects are likely to be considered viable on their own merits. As noted above, a number of Canadian projects, even with export permits already approved, have suspended operations.

Challenging commodity markets often rely on vertical integration to remain profitable. In the same way that independent gasoline stations augment their sales with convenience stores, Jordan Cove has highlighted their integrated Canadian assets as one of the strengths of this project.[19]

A recent investor presentation contained the following graphic of Pembina assets in Western Canada:

[18] LETTER DECISION: "Jordan Cove LNG L.P. (Jordan Cove LNG) 9 September 2013 Application for a Licence to Export Natural Gas pursuant to Section 117 of the National Energy Board Act (NEB Act) National Energy Board (Board) Reasons for Decision," National Energy Board, February 20, 2014, page 9.
[19] Pembina Pipeline Corporation Corporate Update, June 2019, page 7.



[20]

Sources in Colorado are approximately as distant from the Malin hub as the Canadian U.S. border, but Pembina has only one asset in the area. That asset is a minority interest in the Ruby pipeline:

> "Kinder Morgan owns the common interest in and operates Ruby, a 680-mile, 42-inch diameter pipeline system with a capacity 1.5 billion cubic feet per day that extends from Wyoming to Oregon providing natural gas supplies from the major Rocky Mountain basins to consumers in California, Nevada and the Pacific Northwest.
>
> Pembina Pipeline Corporation owns the remaining interest in Ruby in the form of a convertible preferred interest. If Pembina converted its preferred interest into common interest, Kinder Morgan and Pembina would each own a 50 percent common interest in Ruby."[21]

Logically, if Pembina plans to make additional profits through vertical integration, their choice will be to source from Alberta where the majority of their assets are situated.

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[20] Pembina Pipeline Company Investor Day. May 14, 2019, page 15.

[21] https://www.kindermorgan.com/business/gas_pipelines/west/Ruby/ For comparison, TransCanada's GTN pipeline that connects Alberta gas resources to Malin has an operational capacity of up to 2.3 Bcf/day. http://www.tcplus.com/GTN/

IV. Jordan Cove's Import and Export License Applications

Jordan Cove withdrew its FERC application for an LNG import terminal in 2012. Soon afterwards, Jordan Cove applied for a natural gas export license at Canada's National Energy Board, a natural gas import license at the Department of Energy's Office of Fossil Energy, and an LNG export license at the Office of Fossil Energy.

Each of Jordan Cove's license applications – one in Canada and two in the United States – specifically reference the export of Canadian natural gas through the United States via the proposed export terminal at Coos Bay.

Jordan Cove's export permit application at the NEB states:

> 3. The proposed location of Jordan Cove has benefits for Canada, Western Canada's natural gas producers, and Alberta's petrochemical industry. By utilizing existing natural gas transmission systems in Alberta and British Columbia, natural gas supplies for Jordan Cove can be entirely sourced from the Western Canadian Sedimentary Basin ("WCSB"), keeping pipelines and related facilities used and useful, resulting in lower tolls. The petrochemical facilities located at Joffre and Fort Saskatchewan, Alberta, rely on ethane feedstock produced by the extraction plants located on the west-leg of Alberta's natural gas transmission system. Maximizing gas flows through the west-leg delivery system contributes to providing ethane feedstock to Alberta's petrochemical industry. Overall, Jordan Cove will allow for efficient expansion of Canada's natural gas market opportunities.
>
> 4. Use of the existing natural gas pipeline networks of both TransCanada PipeLines and Spectra will help to reduce or eliminate both timing and cost risks associated with new, large-scale, pipeline infrastructure development. With respect to the TransCanada pipeline network, natural gas will be transported on the NOVA Gas Transmission Ltd. system and Foothills Pipe Lines (South B.C.) Ltd. system to the Canada/U.S. border for export at Kingsgate. With respect to gas transportation by Spectra, gas supplies will be gathered and transported on Spectra's BC system through to Kingsvale where, under a proposed common rate structure with FortisBC, supplies will be transported to the Canada/U.S. border for export at Kingsgate. Gas volumes could also flow on the Spectra system to the Canada/U.S. border for export at Sumas, with subsequent swap, exchange or transportation to Jordan Cove.

> 5. For gas exported at Kingsgate, gas supplies will be transported on the Gas Transmission Northwest system ("GTN") to the Malin Hub, located near Malin, Oregon. From the Malin Hub, gas supplies will be transported by the proposed Pacific Connector Gas Pipeline ("Pacific Connector") to Jordan Cove. All existing pipeline routes, as well as the location of Jordan Cove and the Pacific Connector are shown on Figure 1.[22]

Not surprisingly, Jordan Cove's contemporaneous permit application at the DOE's Office of Fossil Energy makes the same statement:

> Import Points: Gas is proposed to be imported at two points on the Canada/United States border. Primarily, gas will cross the border near Kingsgate, British Columbia/Eastport, Idaho (Kingsgate/Eastport) having been transported in Canada on the existing natural gas pipeline networks of both TransCanada PipeLines (using the NOVA Gas Transmission Ltd. And Foothills Pipe Lines (South B.C.) Ltd. Systems) and Spectra (using its BC system to Kingsvale and from there the Spectra/FortisBC Enhancement). This imported gas will then be transported on the existing Gas Transmission Northwest system (GTN) to the Malin Hub, where there will be an interconnection with PCGP, the only new pipeline facility to be constructed in connection with the Project. Alternatively, gas may flow on the Spectra system to the Canada/U.S. border for export near Huntingdon, British Columbia/Sumas, Washington (Huntingdon/Sumas), where it will be transported on Williams' Northwest Pipeline for physical flow, swaps or exchanges to PCGP.[23]

Finally, Jordan Cove's application for an LNG export license reiterates the same basic statement that the exports will be sourced from Canada:

> It is important to note that, especially in its initial years, Jordan Cove exports will draw significantly on Canadian as opposed to U.S. natural gas supplies.[…] The Navigant Study notes that the British Columbia Ministry of Energy and Mines and the National Energy Board of Canada have recently estimated the marketable gas in place in the Horn River Basin alone to be between 61 and 96 Tcf, with total gas in place estimated at 372 Tcf. The other major shale basin in British Columbia, the Montney, has been estimated to contain 65 Tcf of recoverable resources.[…] Other recent esti-

[22] Application by Jordan Cove LNG L.P. for a licence pursuant to section 117 of the National Energy Board Act authorizing the export of gas Appendix A, Veresen, pages 1 and 2.
[23] APPLICATION FOR LONG-TERM AUTHORIZATION TO IMPORT NATURAL GAS FROM CANADA, Jordan Cove LNG L.P., October 21, 2013, pages 7 and 8.

> mates of these resources are even higher[…] and, depending upon which estimate, point to a resource base with a reserve life of 350 to 1,000 years based upon current total demand in British Columbia of one Bcf of gas per day.[24]

V. Conclusion

From the inception of Jordan Cove's reversal from an import terminal to an export terminal, management at Veresen and Pembina have tied the project to Alberta natural gas supplies. This is also reflected in the export and import license applications in the United States and Canada.

In terms of economics, this makes good sense. Prices in Alberta are significantly less than those at the Opal hub in Wyoming.[25] This also utilizes Pembina's other natural gas assets which are primarily situated in Alberta. A profit maximizing entrepreneur would seek the benefits from vertical integration as well as the lowest supply costs.

[24] Application of Jordan Cove Energy Project, L.P. for Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations, FE Docket No. 12-32-LNG, March 23, 2012, pages 11 and 12.
[25] See footnote 8, above, for example.

Foreign or Domestic?

The source of the natural gas that will be processed at the proposed Jordan Cove LNG facility

Prepared for Niskanen Center

July 2, 2019

AUTHOR

Rachel Wilson

Synapse Energy Economics, Inc.

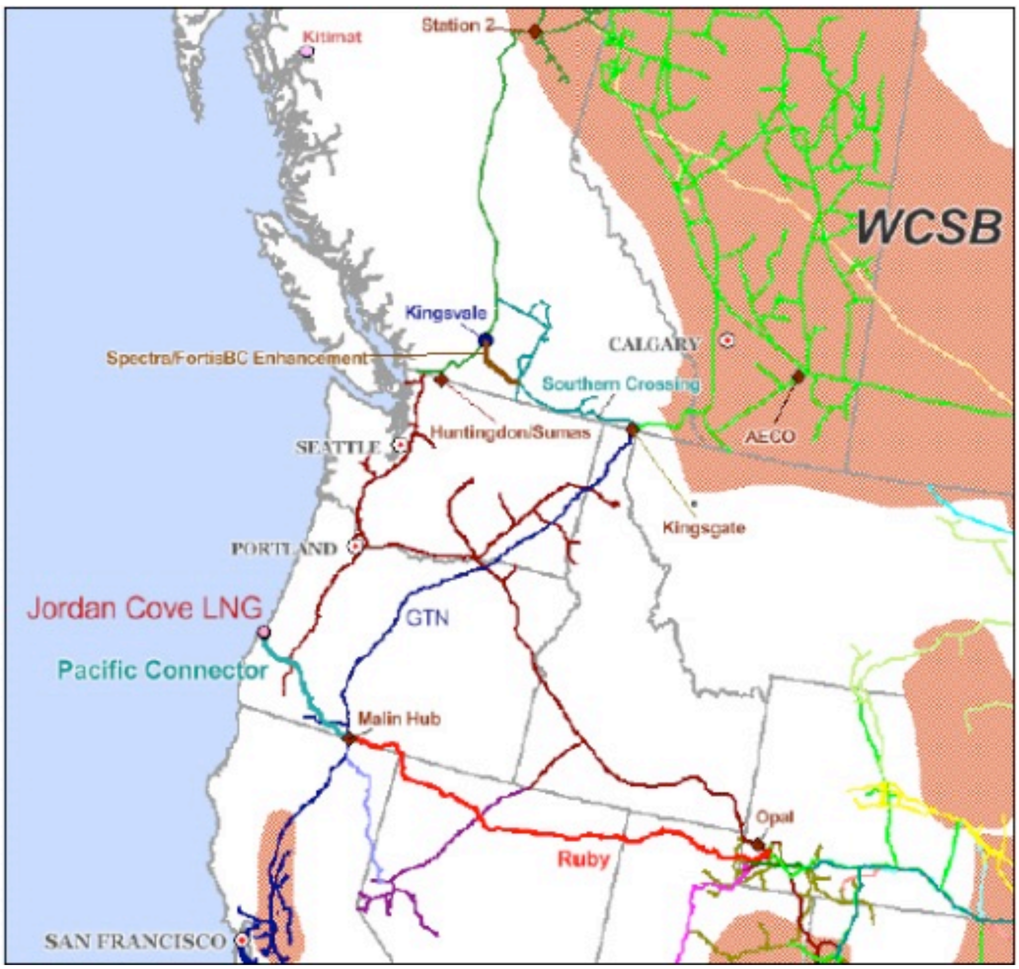
485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

Introduction

Synapse Energy Economics, Inc. was engaged by the Niskanen Center to compare the economics of the potential sources of natural gas that would fuel the proposed Jordan Cove project, which consists of two primary components. The first is a liquefied natural gas (LNG) terminal located in the Port of Coos Bay in Coos County, Oregon, with a liquification design capacity of approximately 1 billion cubic feet per day. The second is the 36-inch diameter "Pacific Connector" gas pipeline, intended to transport natural gas from the Malin Hub to the new LNG terminal.[1] The proposed Jordan Cove project infrastructure is shown in Figure 1, along with other existing natural gas pipeline infrastructure and trading hubs in the Northwest.

Figure 1. Jordan Cove project and existing natural gas infrastructure



Source: Navigant Consulting. September 2013. Supply and Demand Market Assessment and Surplus Evaluation Report. Prepared for Jordan Cove LNG L.P.

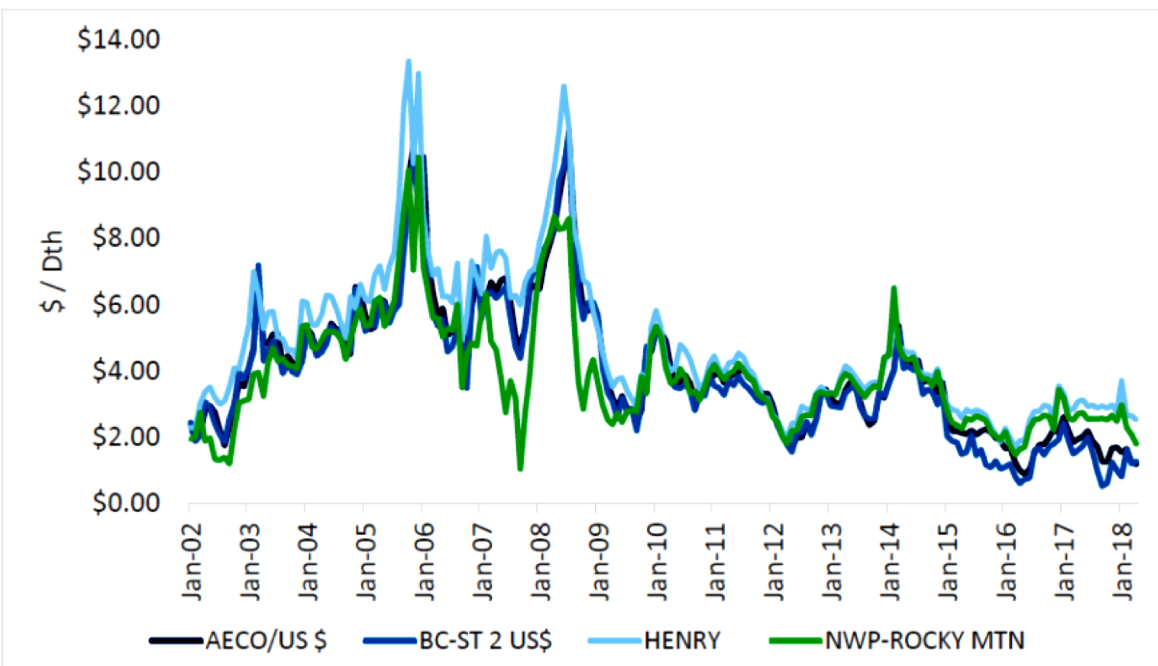
[1] Jordan Cove Project. Accessed June 24, 2019 and available at: https://www.jordancovelng.com/projectcmgh.

Natural gas from Canada would travel from the Kingsgate Hub via the Gas Transmission Northwest (GTN) pipeline while natural gas from the Rocky Mountain region would travel from the Opal Hub via the Ruby pipeline. It is highly likely that the Jordan Cove project would source most, if not all, of its natural gas designated for export from Canadian sources rather than from the Rocky Mountain region. Canadian gas supplies will continue to grow, and prices will be cheaper than natural gas sourced from the Rockies. In addition, documents supporting the applications for permission from the Canadian and U.S. governments to obtain natural gas supplies from Canada show that Jordan Cove developers intend to purchase primarily Canadian gas to supply the proposed project.

Prices for Canadian natural gas are lower than for gas from the Rocky Mountain region

Natural gas customers in the Pacific Northwest have access to gas supplies from both Canada and the Rocky Mountain region and thus can source gas from the least costly area (subject to constraints on long-haul pipelines). As shown in Figure 2, natural gas from the Rocky Mountains (NWP-ROCKY MTN) was less expensive than Canadian gas (AECO and BC-ST 2, which are shown in Figure 1) in many historical years, particularly between 2006 and 2010. That trend reversed in 2015, however, and for the past several years Canadian gas has been much less expensive for consumers in the Pacific Northwest.

Figure 2. Historical natural gas prices at select trading hubs

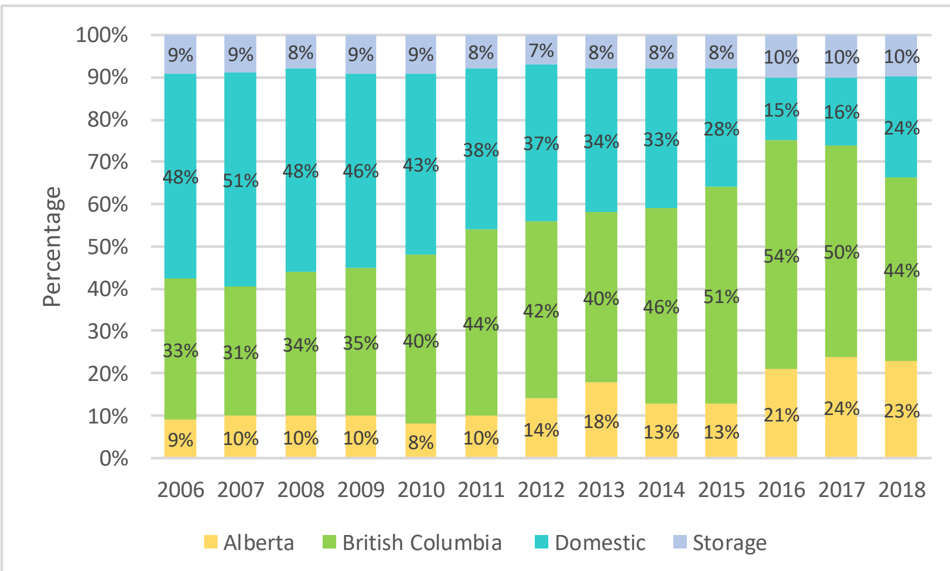


Source: Avista Corporation. 2018. Natural Gas Integrated Resource Plan. Page 96.[2]

[2] AECO refers to the AECO-C-Nova Inventory Transfer market center located in Alberta. BC-ST 2 is the Station 2 Hub located at the center of the Enbridge Westcoast Pipeline system connecting to northern British Columbia. Henry refers to Henry Hub. NWP-Rocky Mountain is the pricing point on the southern end of the NWP system in the Rocky Mountain region.

During the period in which natural gas from the Rockies was cheaper than gas from Canada, consumption of gas from that region in the Pacific Northwest peaked at 51 percent of the total in 2007. Over the last several years, however, natural gas production in British Columbia has grown. Increased supply has led to the declining prices for Canadian gas seen in Figure 2 and the increase in natural gas use from Canada seen in Figure 3. More than two-thirds of the natural gas consumed in the Pacific Northwest region came from Canada in 2018. Figure 3 shows the portions of natural gas consumed in the Pacific Northwest that came from the Rocky Mountain region and from Canada between 2006 and 2018.

Figure 3. Percentage of natural gas supply to the Pacific Northwest from Canada and the Rocky Mountain region

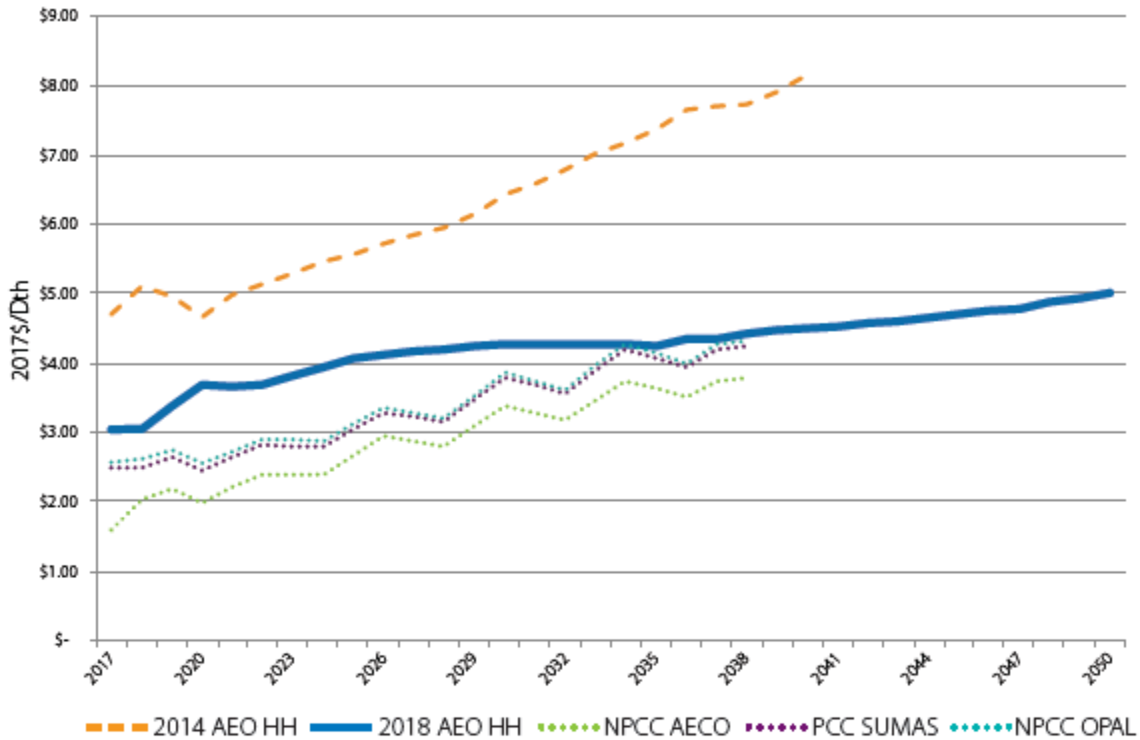


Sources: Northwest Gas Association. 2016. Pacific Northwest Gas Market Outlook. Page 6.
Northwest Gas Association. 2018. Pacific Northwest Gas Market Outlook. Page 6.

We can expect these price and supply trends to continue, as production from the Rocky Mountain region is expected to remain flat over the next decade while production from the Western Canadian Sedimentary Basin (WCSB) is expected to grow by approximately 2 billion cubic feet per day in the same time period.[3] Figure 4 shows prices at the AECO Hub in Canada trending below the Rocky Mountain Opal Hub by approximately $0.50/Dth through 2038.

[3] Northwest Gas Association. 2018. *Pacific Northwest Gas Market Outlook*. Pages 5-6.

Figure 4. Forecasted natural gas prices at select hubs



Source: Northwest Gas Association. 2018. Pacific Northwest Gas Market Outlook. Page 8.[4]

Natural gas flowing to the proposed Jordan Cove project must also include a transportation cost to ship the gas from either the Kingsgate Hub in Canada along the GTN pipeline or from the Opal Hub in the Rockies along the Ruby pipeline. Table 1 and Table 2 show the transportation charges associated with the GTN and Ruby pipelines, respectively, calculated from the rate schedules shown in the tariffs filed by the pipeline companies with the Federal Energy Regulatory Commission (FERC). Table 3 compares the price of natural gas at the Kingsgate Hub and transportation along the GTN pipeline (gas obtained from Canada) with the price of natural gas at the Opal Hub and transportation along the Ruby pipeline (gas obtained from the Rocky Mountain region).

[4] The sources of the "2014 AEO HH" and "2018 AEO HH" are the US Energy Information Administration (US EIA) 2014/2018 Annual Energy Outlook (AEO) for Henry Hub. The NPCC forecasts are from the Northwest Power and Conservation Council (NPCC) 7th Power Plan Midterm Assessment from 2017 for the AECO, Sumas, and Opal natural gas trading hubs.

Table 1. Tariff – Kingsgate to Malin along the GTN Pipeline

	Rate	Unit
Daily Mileage Rate	$0.000391	Dth-Mile
Daily Non-Mileage Rate	$0.030954	Dth
Delivery Charge	$0.000016	Dth-Mile
Fuel Charge (June 2019)	$0.015	Dth
Mileage	612.6	Miles
Total per dth per day	$0.30	

Source: Gas Transmission Northwest LLC. FERC Gas Tariff. Statement of Rates version 18.0.0. Effective January 1, 2019.

Table 2. Tariff – Opal to Malin along the Ruby Pipeline

	Rates per Dth
Monthly Reservation Rate	$34.5826
Commodity Rate	$0.0100
Electric Power Cost	$0.0450
Total per dth per day	$1.19

Source: Ruby Pipeline, LLC. FERC Gas Tariff. Service Rates Version 31.0.0, Effective March 31, 2019.

The cost to transport gas along the GTN pipeline from Canada is approximately one-quarter of the cost to transport gas along the Ruby pipeline. Table 3 compares the price of natural gas at the Kingsgate Hub and transportation along the GTN pipeline (gas obtained from Canada) with the price of natural gas at the Opal Hub and transportation along the Ruby pipeline (gas obtained from the Rocky Mountain region).

Table 3. Hub prices plus transportation costs

	2021 Hub Price	Transport Price
	$/dth	$/dth/day
Kingsgate	$1.92	$0.30
Opal	$2.01	$1.19

Source: Hub prices are from: Bonneville Power Administration. 2019. BP-20 Rate Proceeding. Initial Proposal: Power Market Price Study and Documentation. BP-20-E-BPA-04.

When the natural gas hub price and transportation price are taken together, it becomes clear that it is much cheaper for Jordan Cove LNG to obtain natural gas from Canadian suppliers for export overseas.

Jordan Cove has stated its intent to source most, if not all, of its natural gas from Canada

The Jordan Cove LNG project applied for a license to source Canadian natural gas from the WCSB into the United States for export at the proposed LNG terminal. Developers also stated in the licensing application that the project may be supplied with natural gas from the Rocky Mountain region of the United States but noted in responses to an information request from the National Energy Board (NEB) of Canada that "the mention of the U.S. Rocky Mountain region…simply relates to a potential option for obtaining gas resources for the LNG facility. Like other Canadian LNG export applications, Jordan Cove LNG seeks to preserve the flexibility to source all of its project requirements from Canada…"[5]

In February 2014, the NEB granted Jordan Cove LNG the requested license to export Canadian natural gas. The license has a duration of 25 years and allows for annual export volumes of 1.55 billion cubic feet per day for pipeline fuel and fuel use at the terminal.[6] The U.S. Department of Energy gave its approval for the corresponding import of natural gas from Canada to the Jordan Cove LNG facility in March 2014.[7]

In the NEB's assessment of the Jordan Cove license application, it had to determine whether the natural gas proposed for export at Jordan Cove exceeded the expected surplus after considering projected Canadian demand for natural gas. Jordan Cove submitted a study by Navigant Consulting that concluded that natural gas supplies in the United States and Canada are abundant and can support both domestic market requirements and LNG export demands. In its analysis, Navigant noted that Jordan Cove applied for Canadian export authority to cover the entirety of potential LNG shipments from the project and "anticipates sourcing much, if not all, of its exports from Canadian natural gas supplies."[8]

This report has demonstrated that both Jordan Cove's stated intentions and the economics of western Canadian and domestic Rocky Mountain natural gas supplies support the conclusion that Jordan Cove intends to supply its proposed LNG export facility with Canadian gas.

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[5] Jordan Cove LNG L.P. (Jordan Cove LNG). Jordan Cove LNG Response to NEB Information Request No. 1. Application for a License to Export Natural Gas pursuant to Section 117 of the National Energy Board Act. Filed 9 September 2013 (Application). File OF-EI-Gas-GL-J705-20132-01 01 1.1.

[6] National Energy Board, Canada. February 20, 2014. *Letter Decision.* File OF-EI-Gas_GL-J705-2013-01 01.

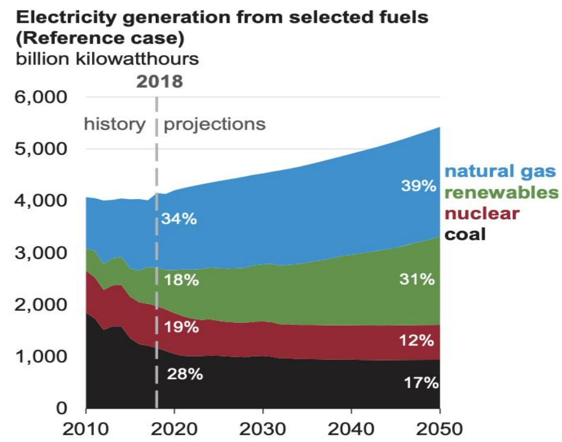
[7] U.S. Department of Energy, Office of Fossil Energy. March 18, 2014. *DOE/FE Order No. 3412 Granting Long-Term Multi-Contract Authorization to Import Natural Gas from Canada to the Proposed Jordan Cove LNG Terminal in the Port of Coos Bay, Oregon*. FE Docket No. 13-141-NG.

[8] Navigant Consulting. September 2013. *Supply and Demand Market Assessment and Surplus Evaluation Report*. Prepared for Jordan Cove LNG L.P.

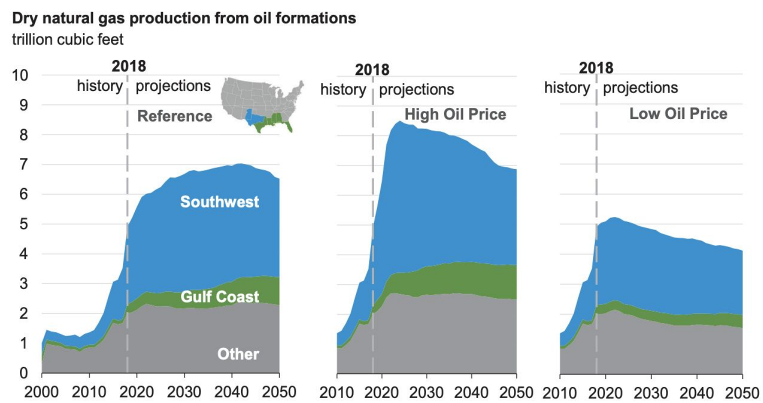
Natural Gas Price Outlook:

U.S. Energy Outlook 2019 (https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf)

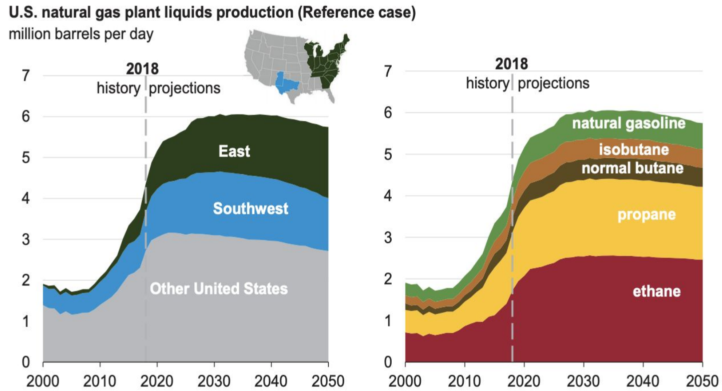
- Slow growth in US energy consumption and increased production of natural gas indicate that the US will become a net energy exporter by 2020. (12)
  - U.S. has been a net natural gas exporter since 2017. (14)
- Natural gas (and NGPLs) currently experiencing the greatest production growth in the US among fossil fuels. (12)
  - Natural gas projected to rise from 34% of 2018 electricity generation to 39% by 2050.



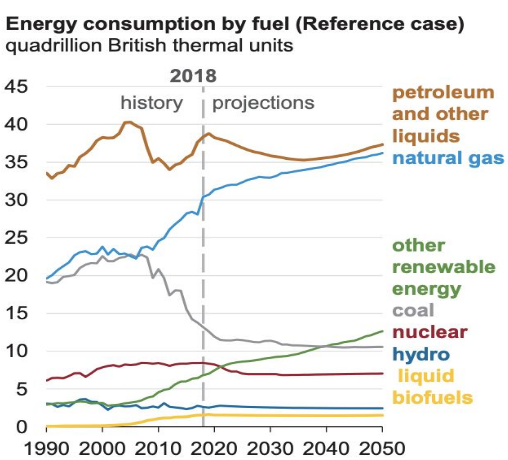
- Natural gas prices are projected to remain comparatively low during the projection period (2018-2050), likely leading to increased natural gas exports and a larger utilization of natural gas in the power sector. (12)
  - Low natural gas prices have helped lower wholesale electricity prices. (22)
  - Natural gas prices are sensitive to factors affecting supply- i.e. domestic resource and technology assumptions. (34)
  - "By 2050 consumption of natural gas increases even as production expands into more expensive-to-produce areas, putting upward pressure on production costs." (34)
- Further downward pressure on natural gas prices are currently occurring as Southwest region becomes the driver of US natural gas production from tight oil formations. (18)
  - Growth in production in the Southwest region projected to level off after 2030. (78)

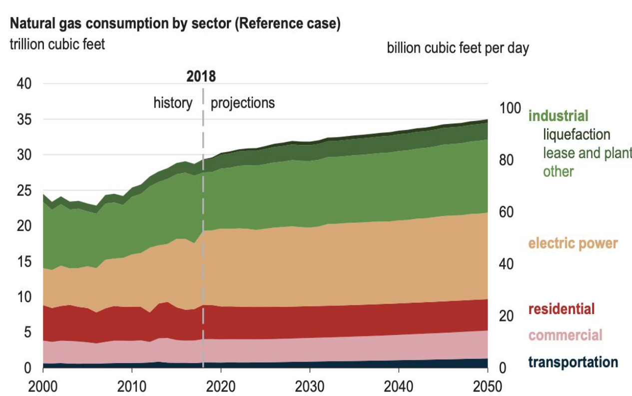


- Dry natural gas production from oil formations is anticipated to remain at around 17% through 2050. (18)
- Drilling in oil formations is primarily dependent on crude oil prices, so a drop in crude oil prices increases the production of natural gas putting a downward pressure on the cost of natural gas. (18)



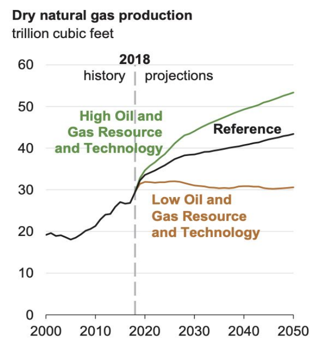
- Natural gas consumption is projected to rise as the price of natural gas is anticipated to remain low. Industrial sector projected to become the largest consumer of natural gas in the early 2020s. Power sector is also anticipated to increase natural gas utilization (28).
    - Increased natural gas consumption in the power sector is supported by the expiration of renewable tax credits in the mid-2020s and a decline in coal and nuclear energy generation. (82)
    - Natural gas in residential and commercial sector projected to remain about the same. (82)
        - Natural gas consumption by commercial buildings is projected to rise by 0.5% per year from 2018 to 2050 while natural gas in the residential sector is anticipated to fall 0.3% per year as natural gas is used less for residential space heating. (134)

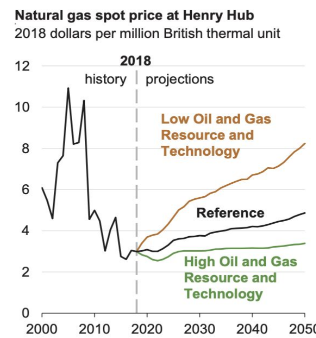




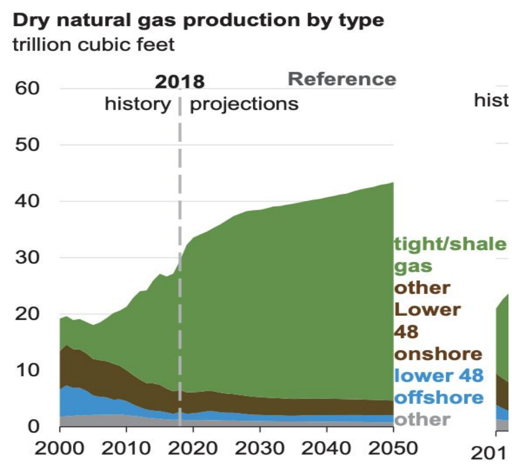
- Natural gas production expected to grow 7% per year from 2018 to 2020. (72)
    - Growth projected to slow to less than 1% per year after 2020 because of decreased domestic demand for natural gas and decreased export demand for US natural gas. (72)

- After 2020, production of natural gas is projected to grow at a higher rate than consumption leading to greater exports of natural gas. (72)
- Natural gas prices expected to remain below $4 million/Btu through 2035, and below $5 million/Btu through 2050 because of increase in lower-cost resources. (74)
    - To satisfy demand, production must be expanded into less prolific and more expensive-to-produce areas, putting upward pressure on production costs. (74)
    - Growing demand is responsible for the rising spot prices of natural gas. (74)

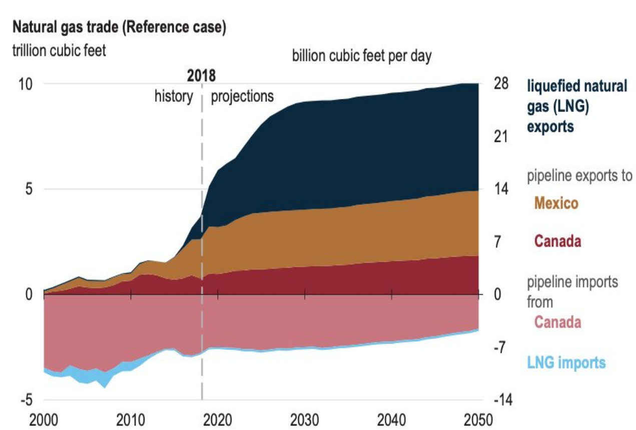




- Technology advancements and high volume of resources allows for decreasing production cost of natural gas from tight oil and shale gas resources. (76)
    - Onshore production of natural gas from sources other than tight oil and shale gas expected to decline through 2050. (76)
    - Offshore natural gas production expected to remain about the same. (76)

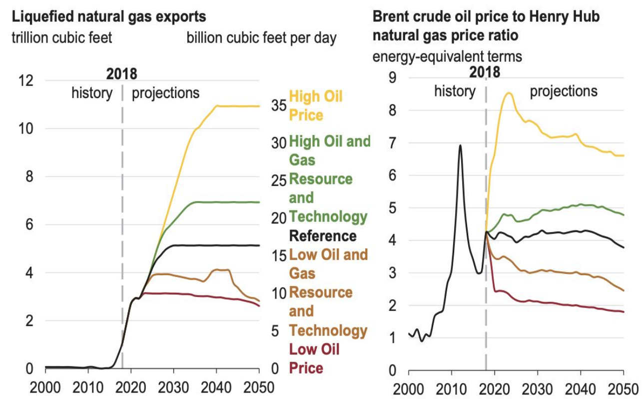


- Gulf Coast anticipated to become the fastest growing domestic demand market. (80)
- Exports to Mexico and LNG exports are expected to increase until 2025 (pipeline infrastructure to Mexico already in place); increased exports to Eastern Canada because of proximity and pipeline infrastructure (84)
    - Exports to Mexico begin to decline as Mexican domestic natural gas begin displacing US imports by 2030; LNG exports continue rising through 2030. (84)
    - LNG exports expected to expand as export facilities complete construction through 2022 and because of growing Asian demand. LNG exports expected to become less competitive and

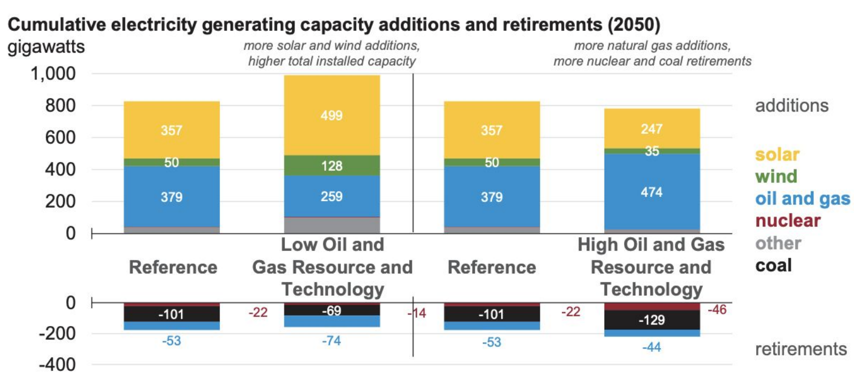


experience slower growth through 2050. (84)

- LNG exports are sensitive to both oil and natural gas prices. (85)
  - Crude oil, to some extent, functions as a natural gas substitute. (86).
  - Demand for LNG increases partially as a result of a consumer shift away from petroleum (86).
  - "As more natural gas is traded via short-term contracts or traded on the spot market, the link between LNG and oil prices weakens over time." (86)

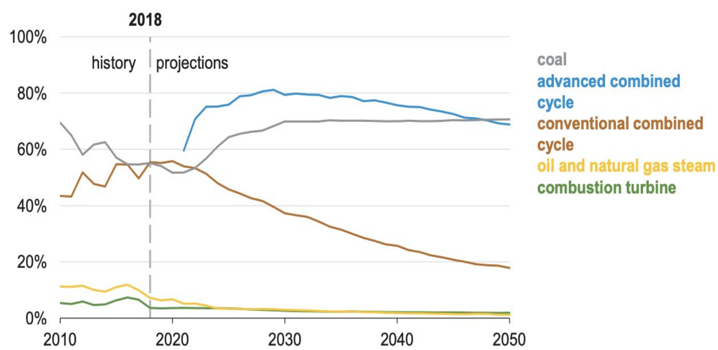


- Low natural gas prices have decreased the competitiveness of coal power generation. (92)
  - Natural gas projected to steadily grow and remain the dominant source of energy in the power sector through 2050. (92)
- New high-efficiency natural gas-fired combined cycle and renewables are projected to be added steadily through 2050 to meet growing electricity demand. (94)



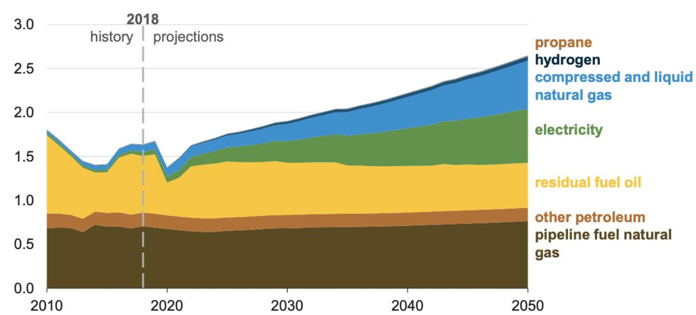
- Electricity generation costs are expected to fall by around 15% from 2018 to 2050. (98)
  - Average electricity prices projected to fall 4.2% from 2018 to 2022 as a result of customer rebates (Tax Cuts and Jobs Act of 2017) and lower construction/ operating costs of new plants. (98)
  - Transmission, distribution costs expected to rise between 18-24% as a result of updating infrastructure and bringing renewables into the grid.
- Lower natural gas prices are expected to accelerate the retirement of nuclear power generation. (105)

  - Lower cost natural gas options are more competitive with nuclear plants, especially nuclear plants with high operating costs and in regions with deregulated wholesale power. (106)
- "Coal-fired generating capacity decreases by 86 gigawatts (GW) (or 36%) between 2018 and 2035 as a result of competitively priced natural gas and increasing renewables generation before leveling off near 155 GW (in the Reference case) by 2050." (108)
- Lower operating costs and efficiency favor utilization of new CC natural gas-fired units with high capacity factors around 76% over coal, but as natural gas prices begin to increase relative to coal prices later, both energy sources are expected to converge to around 70% utilization by 2050. (112)



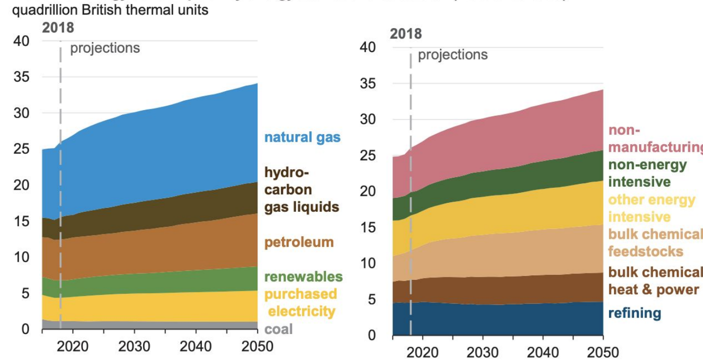
- Natural gas consumption increases during the entire projection period because of growing use of heavy-duty vehicles and freight rail. (130)

Transportation sector consumption of minor petroleum and alternative fuels (Reference case)
quadrillion British thermal units



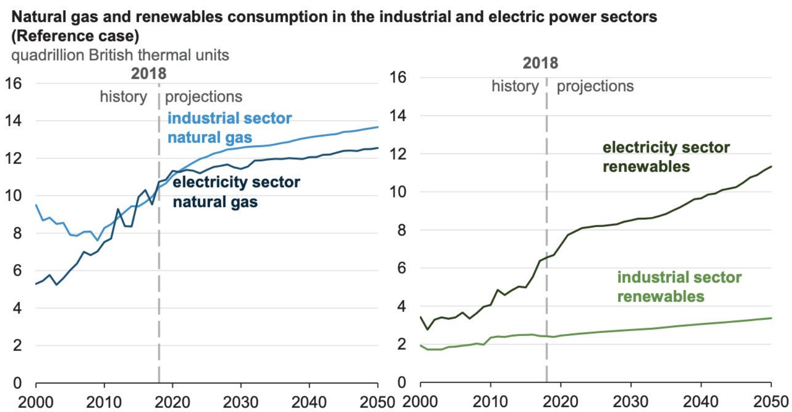
- Natural gas prices in the commercial and residential sector are projected to rise about 0.9% per year through 2050, decreasing consumption in the residential sector. (146)
  - Even with rising natural gas prices, commercial natural gas consumption is expected to rise by 0.5% per year until 2050. (146)
  - "Commercial natural gas-driven generating capacity in 2050 grows to nearly five times its 2018 level." (146)
- Natural gas & petroleum account for most delivered industrial energy consumption. (152)
  - Energy intensity is projected to decline by about 0.9% per year from 2018 to 2050 as a result of

Industrial energy consumption by energy source and subsector (Reference case)
quadrillion British thermal units

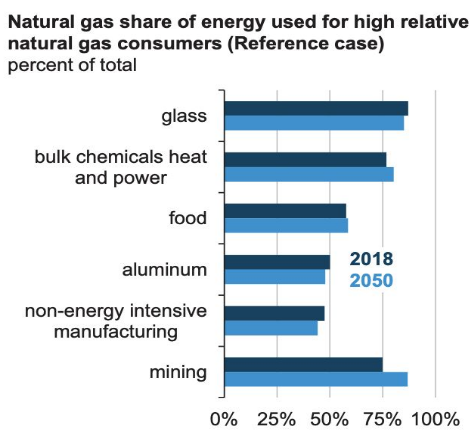


more efficient capital equipment and a shift toward more non-energy intensive industries.

- After the mid-2020s the industrial sector is projected to use more natural gas than the power sector. (156)
    - The chemical industry within the industry sector utilizes natural gas as chemical feedstock. (82)
    - Increased natural gas use in the industrial sector is largely a result of increased energy use for heat and power, lease and fuel for plants, and energy use for liquefaction. (156)
        - Energy use to liquefy natural gas for export increases by 5% per year. (152)



- Four major energy-intensive industries, the entire non-energy intensive industry, and the mining industry are projected to use natural gas for more than 40% of their energy needs in 2050. (158)
    - These industries consumed 7.2 quadrillion Btu of natural gas in 2018 and are projected to use 10.0 quadrillion Btu by 2050. (158)



BP 2019 Energy Outlook - U.S. Specific Insights

(https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/energy-outlook/bp-energy-outlook-2019-country-insight-us.pdf)

- -1% decline in US energy consumption from 2017 to 2040.
    - In 2040, U.S. comprises 12% of global energy consumption.
- +29% growth in U.S. energy production from 2017 to 2040.

- In 2040, U.S. comprises 14% of global energy production.
- Natural gas production expected to rise by 54% by 2040.
- U.S. is projected to remain the largest producer of liquid fuels and natural gas.
  - Natural gas outputs are expected to rise from 400 Bcm to over 1130 Bcm; LNG exports to rise to over 175 Bcm

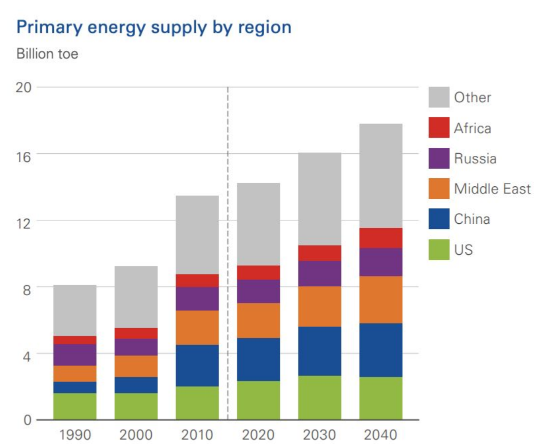
- Natural gas demand is projected to pass demand for oil in the early-2030s.
- Natural gas is expected to become the leading source of fuel, making up 37% of energy consumption by 2040 compared with 28% today.
- By 2040 natural gas and renewables are projected to be nearly equal sources of power generation.

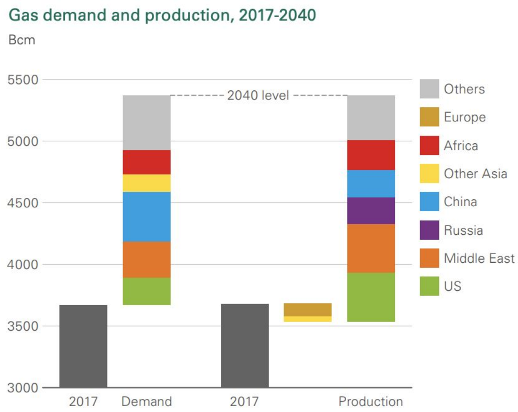
	Level		Shares		Change (abs.)		Change (%)		Change (annual)*	
	2017	2040	2017	2040	1995-2017	2017-2040	1995-2017	2017-2040	1995-2017	2017-2040
Primary energy consumption (units in Mtoe unless otherwise noted)										
Total	2235	2223			164	-12	8%	-1%	0.3%	0.0%
Oil† (Mb/d)	19	15	39%	31%	1	-3	6%	-18%	0.3%	-0.9%
Gas (Bcm)	739	957	28%	37%	141	218	24%	29%	1%	1.1%
Coal	332	138	15%	6%	-149	-194	-31%	-58%	-1.7%	-3.8%
Nuclear	192	104	9%	5%	31	-88	20%	-46%	0.8%	-2.6%
Hydro	67	69	3%	3%	-3	2	-5%	2%	-0.2%	0.1%
Renewables (including biofuels)	132	394	6%	18%	114	263	635%	199%	9.5%	4.9%
Transport^	670	568	30%	26%	113	-102	20%	-15%	0.8%	-0.7%
Industry^	594	598	27%	27%	-84	4	-12%	1%	-0.6%	0.0%
Non-combusted^	116	149	5%	7%	9	32	9%	28%	0.4%	1.1%
Buildings^	855	908	38%	41%	126	53	17%	6%	0.7%	0.3%
Power	912	1026	41%	46%	82	115	10%	13%	0.4%	0.5%
Production										
Oil† (Mb/d)	14	19			5	5	54%	35%	2%	1.3%
Gas (Bcm)	735	1132			231	397	46%	54%	1.7%	1.9%
Coal	371	233			-156	-138	-30%	-37%	-1.6%	-2.0%

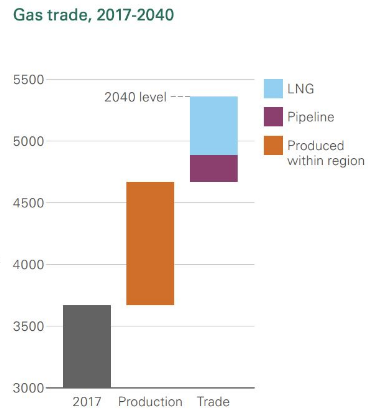
BP 2019 Energy Outlook Report

(https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/energy-outlook/bp-energy-outlook-2019.pdf):

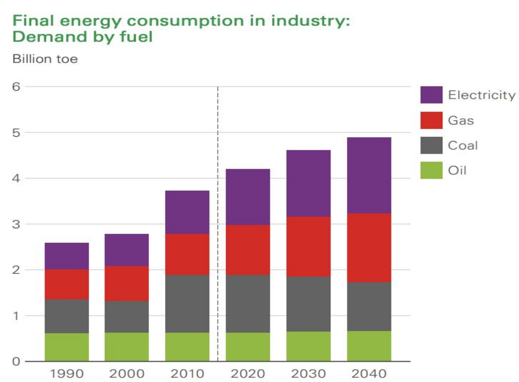
- The US is projected to be the largest contributor to energy growth until the mid-2020s. After the mid-2020s US growth is expected to slow as tight oil production hits peak and begins to decline. (69)
- The growth of US tight oil and shale projected to increase US energy exports. (71)
- Widespread growth in gas demand, US demand depicted in the graph below. (95)







- Natural gas is projected to grow much more than oil or coal (1.7% p.a.), surpassing coal as the second largest source of energy globally and converging on oil by 2040.
- Overall energy consumption slows as energy efficiency increases. (29)
- International industrial energy demand is dominated by the changing energy needs in China. (31)
  - China's industrial energy demand is anticipated to peak in the mid-2020s before shifting toward less energy-intensive industries; growth of industrial production occurring in India, Other Asia, and Africa. (31)
  - Net growth in industrial energy demand anticipated to be met with natural gas and electricity. (31)

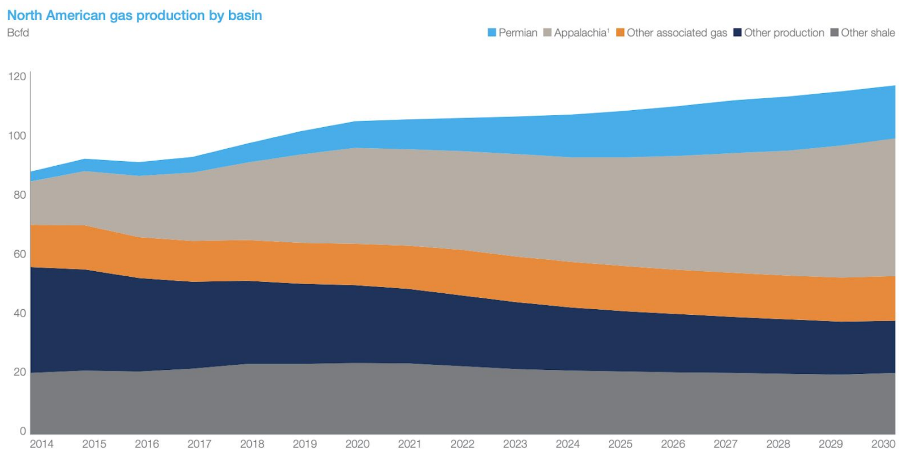


- The transportation sector continues to be dominated by oil despite increasing competitiveness of alternative fuels like natural gas. (45)
  - In transportation sector oil will decrease from a share of 94% to 85% by 2040. (45)
  - Natural gas, electricity, and biofuels account for about half of new energy used in the transportation sector. Natural gas will cover about 5% of transportation demand in 2040. (45)

McKinsey North American Gas Outlook (2018)

(https://www.mckinsey.com/solutions/energy-insights/north-american-gas-outlook-to-2030/~/media/E9DD367260D74CDD8EC8E9287E2628CB.ashx)

- North America has enough gas resources to meet demand for around 25 years below $2.8/mmbtu. (7)
- By 2030 the Permian and Appalachia areas are projected to produce around 55% of the North American market. (8)



- "Despite global oversupply, utilization of US LNG export capacity expected to remain high (80-90%) through 2024 when new capacity comes online." (10)
    - Demand for U.S. LNG increases as liquefaction facilities are utilized at a rate of about 90% until 2020 and more capacity is added. (10)
    - Utilization to remain at about 80% from 2021 to 2024 as new capacity is added primarily from the Middle East and Mozambique. (10)
- Natural gas prices projected to remain constant in short- and medium-term, but anticipated to lower in the long-term. (11)

	Key factors	Near-term (2018-19)	Medium-term (2019-21)	Long-term (post-2021)
Demand	Power: coal, nuclear, renewable – gas switching	▼ Coal/gas switching shifting between $2-3/ mmbtu will keep prices low ▲ Early retirements and cancellation of under construction nuclear plants will increase gas demand	▲ As coal capacity is removed from the power mix, demand response from the power sector due to rising gas prices is limited ▼ Continued decline of renewable costs leads to additional renewable generation	▼ Gas demand decreases due to renewables displacing gas in the power sector, especially as power storage becomes increasingly economics
	Export (LNG, Mexico)	▲ LNG exports will have limited pricingimpact with addition demand of ~2 bcfd ■ Exports to Mexico will have limited pricing impact with an addition demand of ~1 bcfd	▲ LNG exports can increase by ~2 bcfd due to underutilized end-user and portfolio contracts ▲ Pipe capacity addition, CCGT and industrial investment in Mexico will further boost Mexican consumption of US gas by ~2 bcfd	▲ LNG capacity expected to tighten post 2024, increasing LNG plant utilization ▼ Falling solar costs and a rebound in indigenous production slow Mexican demand growth for US gas imports
Supply	Appalachian supply	▲ With increased Appalachian supplies bottlenecked, marginal production will come from higher break-even basins to support LNG exports	▼ As more pipeline infrastructure comes online post-2019, inexpensive Appalachian supplies will continue to grow and limit price fly up potential	▼ Potential for further efficiency gains in drilling and completion decreases break-evens
	Associated gas supply	▼ With efficiency gains and a stable oil price outlook, drilling in oil basins is rebounding, with the Permian taking the lead	▼ At $65/bbl, 'zero cost' associated gas production could increase by ~4.5 bcfd by 2021, most of which is expected from the Permian	▼ Associated gas production continue to increase, making up ~30% of US gas production by 2030
	Others– (e.g., oil field service cost, drilling efficiency)	▲ OFS cost are expected to recover	▲ OFS costs could keep rising if a recovery of commodity price drives a boom in drilling ▼ Drilling efficiency increases and new completion technology will lower well and service costs	OFS costs could keep rising if a recovery of commodity price drives a boom in drilling ▼ Drilling efficiency increases and new completion technology will lower well and service costs

(https://www.mckinsey.com/solutions/energy-insights/north-american-gas-outlook-to-2030)

- North American gas demand is expected to grow by about 2% per year toward 116 billion ft^3/day in 2030.
    - LNG to make up 55% of that growth
- Among other drivers of demand include Mexico, the industrial and petrochemical industries, and changes in energy generation in the power sector.

- Gas demand in the power sector projected to rise 2% per year through 2020, largely replacing coal. After 2020, gas is anticipated to only grow at around 0.3% per year as renewables become more competitive.
- Appalachia is expected to make up about 30% of total US gas production by 2030.
- New pipeline infrastructure will stabilize supply and prices.
- “Supply and demand drivers will enable gas prices to remain stable in the short- to mid-term” (until about 2021).
    - As renewables become more cost-efficient, they are likely to take some of the demand from gas after 2021. McKinsey projects that prices will move below $3 per million Btu.

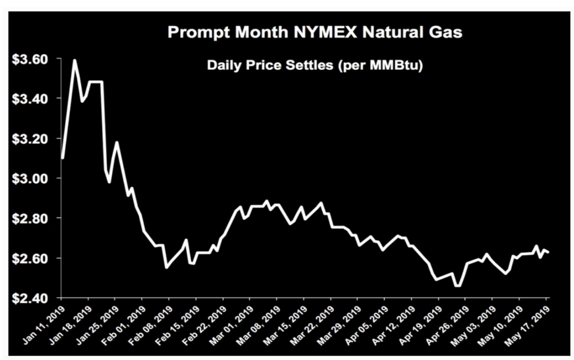
Bloomberg 2019 U.S. New Energy Outlook

(https://about.bnef.com/new-energy-outlook/)

- “We expect global gas prices to converge towards U.S. netback parity and the cost of bringing new LNG liquification capacity online outside of the U.S.”
- The U.S. (as well as India and other countries) are projected to see growing gas demand.
- “Gas-fired power grows just 0.6% per year to 2050, supplying system back-up and flexibility rather than bulk electricity in most markets.”

Forbes- U.S. Natural Gas Prices Remain Low and Stable

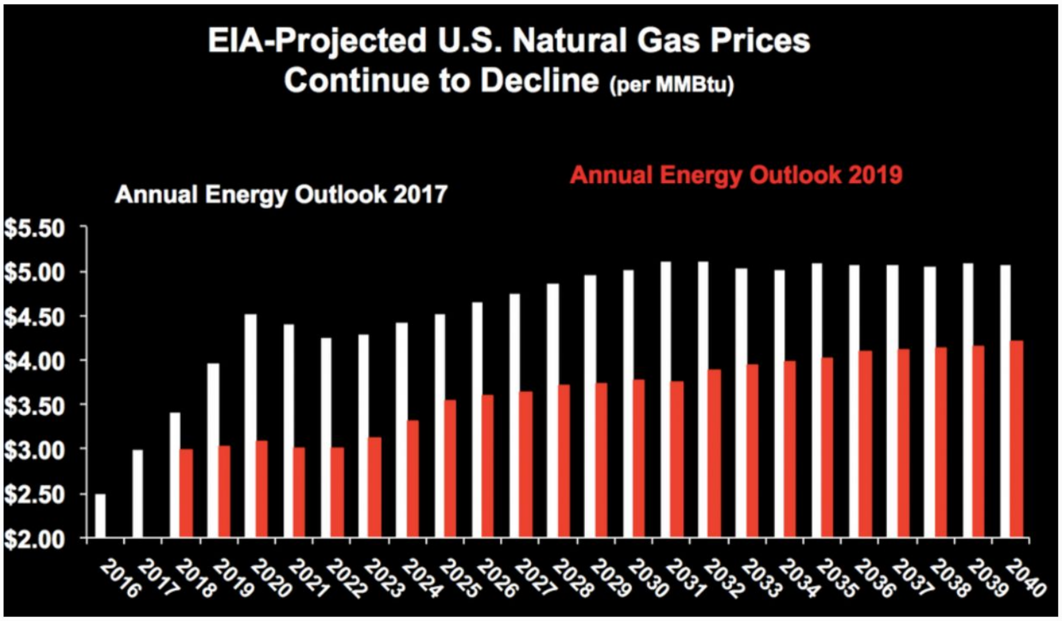
(https://www.forbes.com/sites/judeclemente/2019/05/19/u-s-natural-gas-prices-remain-low-and-stable/#3779bb9e5c0c)



U.S. natural gas prices have been low and stable since the end of January. DATA SOURCE: CME GROUP; JTC

- April 2019 natural prices broke below $2.50 for the first time since June 2016.
- Since April prices have varied less at just around 10%.
- 2019 production has been at 86 Bcf/d compared to 79 Bcf/d in 2018.
    - This 7 Bcf/d has kept prices low while demand has only risen by 5 Bcf/d.
- Natural gas storage deficit is being addressed, further helping to stabilize natural gas markets.
- Three new LNG export facilities are being added with the potential of adding 4 Bcf/d in demand by 2020.
- “Over the past two years, for instance, EIA's forecast for U.S. gas prices in 2030 has plummeted 25%.”

  - Falling prices make natural gas even more competitive compared to other electricity- generating sources in the power sector.
- Natural gas prices in 2030 are projected to remain below $4 per MMBtu in 2030.



Forecasts for future U.S. natural gas prices seemingly get lower every year. DATA SOURCE: EIA; JTC

A Leader of America's Fracking Boom Has Second Thoughts- WSJ (https://www.wsj.com/articles/a-leader-of-americas-fracking-boom-has-second-thoughts-11561388670?mod=hp_lead_pos5)

- "Over the past 10 years, 40 of the largest independent oil and gas producers collectively spent roughly $200 billion more than they took in from operations."
- Under pressure to generate positive cash flows, executives have been slashing overhead and dialing back drilling plans.

U.S. Natural Gas Prices Have Collapsed- Forbes (https://www.forbes.com/sites/judeclemente/2019/06/23/u-s-natural-gas-prices-have-collapsed/#3d5edb93286e)

- "There are no contracts on the forwards curve above $3.00 until January 2024."
- Given that prices were as high as $4.92 in mid-November, nobody projected such a rapid decline in natural gas prices.
- "And such low prices obviously discourage bringing new output online, but I still expect us to surpass 90 Bcf/d in the coming months."
    - Generating more output despite already low prices and oversupply.

Supply Glut Drives Natural Gas Prices to Lowest Since 2016- Yahoo Finance (https://finance.yahoo.com/news/supply-glut-drives-natural-gas-140802595.html)

- Quantifying the oversupply:
    - "Stockpiles held in underground storage in the lower 48 states rose by 115 billion cubic feet (Bcf) for the week ended June 14."
    - Total natural gas stocks at 2.203 trillion cubic feet (Tcf) - 209 Bcf (10.5%) above 2018 levels.
- Consumption has stayed relatively flat while supply has increased.

Natural Gas Price Forecast- Natural gas markets collapsed again- FX Empire (https://www.fxempire.com/forecasts/article/natural-gas-price-forecast-natural-gas-markets-collapsed-again-581779)

- Natural gas prices have continued to decline as "we continue to see a lot of exhaustion in demand and of course concerns about the global economy if the Federal Reserve is looking to cut interest rates."
- " the economies around the world slow down, it's very likely that natural gas demand will continue to fail to catch up to the oversupply of this commodity. There is nothing good-looking about this chart."

The global boom in natural gas demand is about to slow, the IEA says- CNBC
(https://www.cnbc.com/2019/06/07/the-global-boom-in-natural-gas-demand-is-about-to-slow-iea-says.html)

- Global demand for natural gas was 4.6% in 2018, but moving forward is only expected to increase by about 1.6% per year.
    - A large amount of this demand is expected to be generated by China (40% of demand through the next 5 years)
- Although global demand is increasing, a sizeable portion of this demand is overseas so increases in pipelines are not a better way to distribute natural gas. Rising demand abroad will largely be met with LNG exports overseas.

Natural Gas Moves to Lower Lows
(https://seekingalpha.com/article/4271547-natural-gas-moves-lower-lows)

- Natural gas is at its lowest price since 2016.
- Rising inventories of natural gas are primarily responsible for what has pushed natural gas prices so low.

Seeking Growth: What will drive US natural gas demand?- Deloitte
(https://www2.deloitte.com/us/en/pages/energy-and-resources/articles/us-natural-gas-consumption-demand.html)

- "Future demand growth poses other challenges. With expected low-to-moderate economic growth, slowing population growth, and increases in energy efficiency, domestic energy consumption may expand more slowly over the next ten years than the last—and potentially may even decline."
- "Export growth could be limited as global natural gas markets are in a state of flux with a glut of capacity that could potentially last until the early 2020s."
- Projections for the future of natural gas:
    - The market it likely to grow more slowly than it has in the past
    - Prices are anticipated to remain low

Pipeline Bubble

NORTH AMERICA IS BETTING OVER $1 TRILLION ON A RISKY FOSSIL INFRASTRUCTURE BOOM

Ted Nace, Lydia Plante, and James Browning

ABOUT GLOBAL ENERGY MONITOR

Global Energy Monitor (formerly CoalSwarm) is a network of researchers developing collaborative informational resources on fossil fuels and energy alternatives. Current projects include the Global Coal Plant Tracker, the Global Fossil Infrastructure Tracker, the CoalWire newsletter, and the CoalSwarm and FrackSwarm wiki portals.

ABOUT THE GLOBAL FOSSIL INFRASTRUCTURE TRACKER

The Global Fossil Infrastructure Tracker is an online database that identifies, maps, describes, and categorizes oil and gas pipelines and oil, gas, and coal terminals. Developed by Global Energy Monitor, the tracker uses footnoted wiki pages to document each project. For further details, see "Methodology" at http://ggon.org/fossil-tracker/.

AUTHORS

Ted Nace is Executive Director of Global Energy Monitor. Lydia Plante is Researcher and Analyst at Global Energy Monitor. James Browning is Communications Director at Global Energy Monitor.

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FURTHER RESOURCES

For additional data on proposed and existing pipelines, see Summary Data at http://ggon.org/fossil-tracker/, which provides over 30 tables providing results from the Global Fossil Infrastructure Tracker (GFIT), broken down by nation and region. To obtain primary data from the GFIT, contact Ted Nace (ted@tednace.com).

Pipeline Bubble

NORTH AMERICA IS BETTING OVER $1 TRILLION ON A RISKY FOSSIL INFRASTRUCTURE BOOM

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INTRODUCTION: FOOLED ME ONCE

From 2011 to 2016, following a period of heady optimism and over-expansion based on expectations of surging Asian demand, coal mining company values plummeted and bankruptcies decimated the sector (see Sidebar: "The Coal Mining Equities Crash"). Today, investors in the booming expansion of oil and gas infrastructure appear headed for a similar shock, as boom-fueled optimism runs into climate realities and fiscal limits:

- Rapid expansion: A newly completed survey of oil and gas pipeline projects by the Global Fossil Infrastructure Tracker reveals a tripling in the pace of oil and gas pipeline building since 1996, with over half (51.5%) of projects located in North America and gas projects dominating the mix by a 4:1 ratio over oil projects. North America's oil and gas pipeline expansion plans total $232.5 billion (pre-construction and construction) out of total North American oil and gas infrastructure expansion plans of over $1 trillion.

- Reliance on Asian growth: Domestic demand growth cannot support the current North American oil and gas infrastructure boom. Like the over-investment that occurred in the coal sector, the current expansion in oil and gas infrastructure is predicated on a "super cycle" of increased demand from overseas buyers, especially in Asia.

- Sectoral stigmatization on climate grounds: Like the coal sector in the 2011–2016 period, the oil and gas sector faces rapidly growing censure from civil society, including divestment actions by over 1,043 institutions representing over $8.7 trillion in capital. New findings by the Intergovernmental Panel on Climate Change have called for a 65% reduction in oil use and a 43% reduction in gas use by 2050, relative to 2020. Such reductions are incompatible with rapid infrastructure expansion.

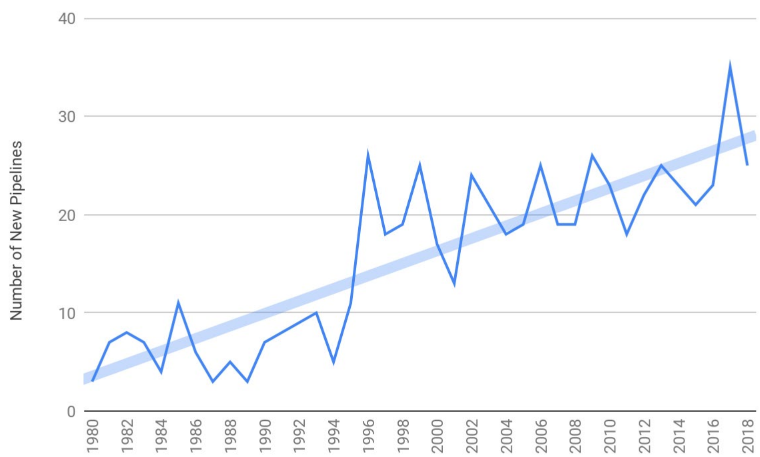
THE NEW PIPELINE BOOM

After adding an average of seven new pipelines a year from 1980 to 1995, the global system added an average of 25 new pipelines a year from 2009 to 2018. Currently 302 new pipelines are under development, including 78 in construction and 166 in pre-construction planning. If built, these projects will increase the number of global pipelines by 29%, including a 35% increase in the number of gas pipelines and a 19% increase in the number of oil pipelines.

GAS DOMINATES THE MIX

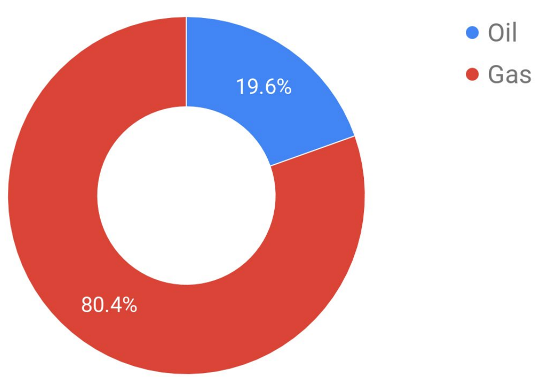
Since 1980, global production of natural gas has grown at three times the rate of oil—148% for gas, 48% for oil (Ritchie 2019). The ongoing production shift toward gas is reflected in the respective length of pipelines under development, which also favor gas over oil by 4:1 ratio, as shown in Figure 2.

Figure 1. New pipelines per year, 1980–2018



Source: Global Fossil Infrastructure Tracker, January 2019.

Figure 2. Shares of Oil and Gas in Global Pipeline Development (by Length)



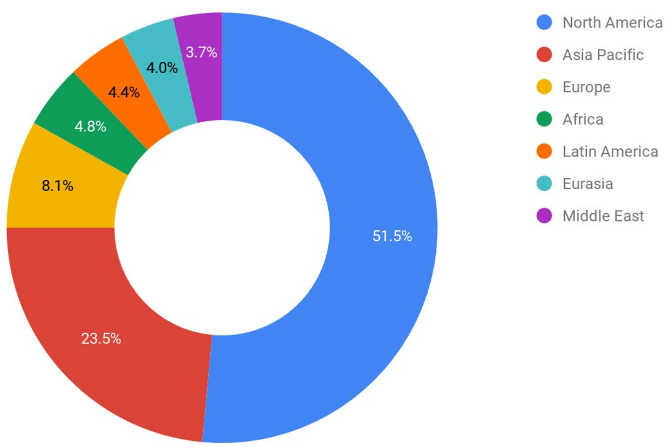
Includes projects in construction and pre-construction stages. Source: Global Fossil Infrastructure Tracker, January 2019.

ACTIVITY BY REGION: NORTH AMERICA'S BUILDING SPREE

By all measures, North America leads the world in development of new pipelines, followed by the Asia Pacific region. As shown in Figure 3 and Table 1, North America accounts for over half of pipeline projects under development (if measured by number of projects) or for over a third (if measured by pipeline lengths). This includes 64% of oil pipelines in development worldwide (36 out of 56) and 48% of gas pipelines in development worldwide (104 out of 216).

North America's pipeline projects are concentrated in three areas. The most active area is the Permian Basin of west Texas and southeast New Mexico, where numerous pipelines aimed at feeding Gulf Coast refineries and export terminals are currently under development. At least 12 pipelines originating in Texas fields are under construction, with an additional 26 in pre-construction development. If built, these Texas-originating pipelines will add over 16,000 km (10,000 miles) to the North American

Figure 3. Regional Shares in Global Pipeline Development (by Number of Projects)



Based on number of projects (construction and pre-construction categories). Source: Global Fossil Infrastructure Tracker, January 2019.

Table 1. Regional Distribution of Pipeline Development (Km)

	Oil		Gas			
Region	**Proposed**	**Construction**	**Proposed**	**Construction**	**Total**	**Share**
Africa	6,602	2,336	8,910	497	18,344	10%
Asia Pacific	952	69	34,775	7,460	43,255	24%
Eurasia	1,384	0	9,510	5,372	16,266	9%
Europe	0	0	13,345	2,520	15,865	9%
Latin America	475	0	6,907	6,145	13,527	7%
Middle East	4,415	0	7,795	1,900	14,110	8%
North America	17,592	2,144	31,356	11,058	62,149	34%
Total	**31,419**	**4,549**	**112,597**	**34,952**	**183,517**	

Source: Global Fossil Infrastructure Tracker, January 2019 pipeline system and will increase the capacity of the system by at least 12 million barrels of oil equivalent per day. By length, Texas-originating pipelines account for 34% of North America's proposed and under-construction new pipelines; by capacity, they account for 40%.

The second major origination area for new pipelines is the Marcellus and Utica shale formations in Pennsylvania, Ohio, and West Virginia, with pipelines feeding refineries and terminals located on the Atlantic coast and Great Lakes. In addition, some pipelines will transport liquid natural gas byproducts within the region to new ethane cracker facilities located along the Ohio River (Bruggers 2009).

The third major origination area is the Canadian tar sands of Alberta, with pipelines transporting oil southwest toward the Pacific coast and southeast toward the Gulf Coast.

Table 2. Pipeline Development by Originating State or Province, Ranked by Length

Originating State or Province	Number	Length (km)
Texas	38	16,747
Alaska	3	4,715
Alberta	10	4,415
British Columbia	8	3,955
Illinois	2	2,334
Oklahoma	8	2,148
Pennsylvania	14	1,974
Ohio	6	1,711
West Virginia	4	1,678
New Mexico	4	1,379
Utah	1	1,046
Louisiana	7	797
Chihuahua	1	625
South Carolina	1	579
Veracruz	2	496
Oaxaca	1	440
Hidalgo	1	420
Oregon	2	394
Wyoming	3	388
San Luis Potosi	1	374
Maryland	1	306
Durango	1	290
New York	1	286
Colorado	4	238
Michigan	2	219
Yucatan	1	159
California	1	155
Washington	1	129
Virginia	1	91
North Carolina	2	79
North Dakota	2	54
New Jersey	1	48
Sonora	2	45
New Hampshire	1	44
North America	**138**	**48,756**

Includes projects in construction and in pre-construction development. Length in km. Source: Global Fossil Infrastructure Tracker, January 2019.

WHAT'S DRIVING THE NORTH AMERICA BOOM?

North America's own domestic appetite for natural gas and oil is not the primary reason for the boom in pipeline activity. According to the U.S. Energy Information Agency, overall U.S. demand for petroleum liquids will decline from 2020 to 2035 by about three quads (quadrillion British thermal units) (U.S. EIA 2019), or about 8% of current consumption. Similarly, for natural gas, domestic demand growth, which the U.S. EIA estimates will be about two quads from 2020 to 2035, or about 10%, is not sufficient to support the large boom taking place in new infrastructure (U.S. EIA 2019).

With domestic demand insufficient to drive the oil/gas infrastructure boom, sponsors of pipeline projects are looking instead to overseas markets, especially the Asia Pacific region, where natural gas is expected increasingly to replace coal in power generation and industrial processes. In this version of the future, encapsulated in the International Energy Agency's "Current Policies" scenario, natural gas demand grows 1.6% percent per year worldwide from 2017 to 2040, with the Asia Pacific region growing at 3.1% per year in the same period as natural gas increasingly replaces coal (IEA 2018). By 2040, gas demand relative to 2017 rises by 55% and oil demand by 26% under the Current Policies scenario.

THE COAL MINING EQUITIES CRASH

On April 13, 2016, the largest U.S. coal company, Peabody Energy, declared bankruptcy. By that point four other major companies had already filed for Chapter 11 protection: Arch Coal, ANR, Patriot Coal, and Walter Energy. One analyst called it "the day coal died in the United States."

What's striking is how fast the coal industry went from boom to bust. In 2010, forecasts about the future of global coal demand closely resembled today's optimistic forecasts about growing global demand for natural gas. Those optimistic expectations were reinforced by a strong upward trend in coal prices, with benchmark coal prices increasing from $100 per tonne in January 2010 to $140 per tonne in January 2011. In early 2011, coal mining company stocks hit an all-time high, as analysts predicted a "super cycle" of growth based on China's domestic consumption. In its *World Energy Outlook 2010*, the IEA projected that the coal mining industry would see continued growth, including a 38% increase in Chinese production from 2008 to 2015, supporting coal-supply infrastructure investment of $720 billion in the period 2010–2035.

Figure 4. Peabody Energy stock chart, 2011–2016

Based on the confluence of indicators pointing safely toward an ongoing boom, coal mining companies took on increased debt as they undertook aggressive ramp-ups in new acquisitions of mines and investments in new mines.

In retrospect, the warning signs were clear, and the parallels with today's gas boom are particularly striking:

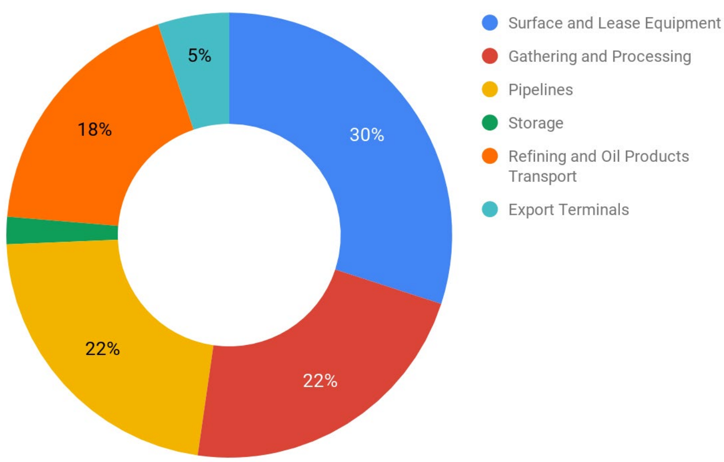
- Mining companies were convinced that coal, long touted as the cheapest fuel, would maintain that advantage into the future. Similarly, today's boom in North American pipelines is based on a belief that the fracking boom has given North American producers a long-term advantage in global markets. But just as the fracking revolution enabled natural gas to push coal out of North American power markets, today plunging solar and wind cost structures threaten to similarly drive the displacement of natural gas.
- Mining companies, along with their political allies in Washington, D.C., and other capitals, failed to factor growing global concern over carbon pollution and other environmental impacts into their growth calculations. As of February 2019, over 24 governments had committed to phasing out coal and over 100 banks and other financial lenders had instituted restrictions on coal financing.

PIPELINES AS PART OF A $1 TRILLION EXPANSION

Banks, equity investors, and bondholders are in the process of placing over $600 billion in bets on an expanded pipeline system with an expected lifespan of 40 years or more. Table 3 estimates the capital costs by region in pipelines that are currently in pre-construction or construction.

As shown in Table 3, $232.5 billion, or 37% of the total, is for pipelines in North America. This estimate falls at the low end of the oil and gas industry's own projections for pipeline capital expenditures for the U.S. in the period 2017–2035, which range from $234 billion to $362 billion and account for 22% of projected capital spending during that period for U.S. oil and gas industry infrastructure, as shown in Figure 5, according to the base case scenario developed for the American Petroleum Institute by ICF (Petak 2017). Applying API's ratio to the $232.5 billion North American and $632.5 billion global estimates shown in Table 3 suggests overall infrastructure expansion plans of $1.05 trillion for North America and $2.9 trillion globally.

Figure 5. Shares of U.S. Oil and Gas Infrastructure Capital Expenditures 2017–2035



Source: Petak, K. et al. "U.S. Oil and Gas Infrastructure Investment Through 2035." American Petroleum Institute, 2017. Base case scenario. http://bit.ly/2SEW72M

Table 3. Estimated Investments in Pipelines Under Development (Billion $)

Region	Gas (billions)	Oil (billions)	Total (billions)
Africa	41.8	31.4	73.2
Asia Pacific	137.4	4.5	141.9
Eurasia	69.9	6.6	76.5
Latin America	35.1	2.3	37.3
Middle East	50.2	21.0	71.1
North America	148.9	83.6	232.5
Total	**483.3**	**149.2**	**632.5**

Includes projects in pre-construction and construction stages. Based on $4.75 million/km ($7.65 million/mile) for proposed onshore US gas pipeline projects in 2015–16, as reported by "Natural gas pipeline profits, construction both up," *Oil & Gas Journal*, November 2018. Based on estimated and reported pipeline lengths, Global Fossil nfrastructure Tracker, January 2019.

INVESTOR RISK FACTOR #1: IS FOSSIL FUEL INFRASTRUCTURE LOSING ITS SOCIAL LICENSE?

The message that today's energy system must transition away from fossil fuels took on new urgency with the release of an October 2018 report by the Intergovernmental Panel on Climate Change (IPCC), "Global Warming of 1.5°C." According to that report, developed by 91 scientists from 40 countries, gas and oil production must begin to drop within the coming decade, not expand further. As shown in Table 4, which is based on pathways that would allow a one-in-two to two-in-three chance of limiting global warming to 1.5°C above pre-industrial levels, gas and oil usage must decline 15% and 21% respectively by 2030 relative to 2020. By 2050, reductions must be steeper: 43% for gas, 65% for oil. Failure to make such changes will result in cascading levels of damage to the global ecosystem and human society, including sea level rise and coastal inundation, heat waves, drought, accelerated species extinction, and widespread crop failures. In North America, the current pipeline boom can only pay off if these warnings are brushed aside and greenhouse gas levels are permitted to rise to ever more damaging levels.

Changing the trajectory of oil and gas use means changing levels of upstream extraction, and it also means avoiding further lock-in of new midstream infrastructure. In that regard, it is important to remember that new infrastructure not only follows the development of new extraction areas, but also facilitates further extraction. For that reason investments in pipelines, terminals, and other midstream components of the energy system are increasingly being challenged on ethical grounds.

Many of those challenging the moral and financial wisdom of fossil fuel investing were once among the industry's most important allies: banks and sovereign wealth funds. Challenges to the social license for fossil fuel infrastructure include divestment actions by over 1,043 institutions representing more than $8.7 trillion in capital (Fossil Free: Divestment 2019), a growing bipartisan support for alternative energy over fossil fuels (Gallup 2016), the proliferation of citizen protests and direct action campaigns targeting individual pipelines or terminals, and a growing array of institutional policies aimed at restricting investment in fossil fuels. Restrictive measures toward oil and gas extraction have been adopted by the World Bank as well as the governments of New Zealand, France, Costa Rica, Belize, New York, and Maryland (Trout 2019). Most recent was been the action of Norway's massive pension fund to divest from independent oil and gas producers and to begin investing in unlisted renewable energy infrastructure (Reed 2019).

The growing trend toward institutional restrictions on support for oil and gas parallels a similar trend by over 100 financial institutions to restrict support for coal. As one analyst noted, "Global capital is fleeing the thermal coal sector. This is no passing fad." (Buckley 2019).

Table 4. Median primary energy supply (Exajoules) for below IPCC 1.5°C pathways with low overshoot.

	2020	2030	2050
Gas	132.95	112.51	76.03
Oil	197.26	156.16	69.94

Source: IPCC, "Global Warming of 1.5°C," Table 2.6, October 2018

INVESTOR RISK FACTOR #2: OVEREXPANSION

A second risk factor for investors in oil and gas pipelines arises from what John Maynard Keynes termed "animal spirits" —the sense of optimism that has arisen from the extraordinary success of the fracking boom. Riding on the enthusiasm and production boosts of the U.S. fracking boom, the last decade of rapid growth for North America's oil and gas producers has created a sense of permanent global dominance. But there are many indicators that the current disproportionate growth in production occurring in North America will fade far sooner than the 40-year expected life of today's infrastructure investments. Overseas, surging growth is projected in numerous new and expanding extraction areas, including the following:

- Middle East. According to the IEA, Middle Eastern supplies of natural gas are expected to rise sharply in the coming decades, as major new fields come into production in Qatar (North Dome field), Iran (South Pars field), and Saudi Arabia. Overall, Middle Eastern production is projected to increase by 65% in 2040 relative to 2017 under the IEA's New Policies scenario (WEO 2018).

- Central and South America. New offshore fields in Brazil (Pre-salt field) and new onshore fields in Argentina (Vaca Muerta) are projected to drive the region's production upward by 60% in 2040 relative to 2017 under the IEA's New Policies scenario (WEO 2018).

- Asia Pacific. According to the IEA, by 2040 China's own production is projected to increase by 142%, with a 40% increase already recorded in 2018 in the Sichuan Basin (Aizu 2018, Jacobs 2019). The IEA projects India's gas production to grow by by 166% by 2040, with the country's oil ministry recently projecting that production would double in the coming four years (Abdi 2018). Finally, the IEA projects Australia's production of natural gas to increase by 98% by 2040 (WEO 2018).

- Africa. Africa's natural gas production is projected to increase by 131%, based on gas discoveries in 14 sub-Saharan countries and a U.S. government program to provide $175 billion in investment funds for the sector (Husseini 2018, WEO 2018).

Overall, global production of natural gas outside North America is projected to increase 46% between 2017 and 2040, while North American natural gas production is projected to increase by 36% in the same period. The discrepancy is even greater in the period from 2025 to 2040, when global production outside North America is projected to grow by 31%, compared to 12% in North America (WEO 2018).

Accelerating renewables also place an overbuilt North American pipeline network at risk of underutilization. Over the past decade, projections by the International Energy Agency about the pace of renewables have consistently proved to be overly conservative. According to Auke Hoekstra, who has documented the IEA's pro-fossil bias, the same tendency applies to battery storage and electric vehicles.

OWNERSHIP AND EXPOSURE

Globally, pipeline construction is primarily in the hands of state-owned enterprises, as shown in Table 5. This domination of transportation infrastructure matches the state domination of other parts of the oil and gas industry, including both reserves and production (Carpenter 2018). By definition, such enterprises are either partly or wholly shielded from private financial markets.

In North America, the ownership pattern is reversed, with most pipeline projects owned by private entities, as shown in Table 6 (on the next page.) One major exception is Alaska, where the quasi-public Alaska Gasoline Development Corporation appears to be weighing whether the $44 billion Alaska LNG pipeline project is too risky. Meanwhile the government of Canada has been widely criticized for acquiring the financially questionable C$5 billion Trans Mountain Pipeline after Kinder Morgan backed out of the project.

Table 5. The Top 20 Global Builders of Oil and Gas Pipelines (by km)

Owner	Proposed	Construction	Total	Ownership	Country
Gazprom	4,625	5,173	9,797	Private	Russia
Ministry of Petroleum of Iran	4,481	1,900	6,381	State-owned	Iran
TransCanada	4,530	1,311	5,841	Private	Canada
Gas Authority of India Limited	3,066	1,373	4,439	State-owned	India
Kinder Morgan	1,304	2,962	4,266	Private	U.S.
Alaska Gasline Development Corporation	3,888	0	3,888	State-owned	U.S.
Plains GP Holdings	2,627	628	3,255	Private	U.S.
Petrobras	0	3,100	3,100	Semi-private	Brazil
Bangladesh Petroleum Corporation	3,010	0	3,010	State-owned	Bangladesh
Iranian Ministry of Petroleum	2,800	0	2,800	State-owned	Iran
Pasargad Energy Development Company	2,800	0	2,800	Private	Iran
Gujarat State Petronet	709	2,042	2,751	State-owned	India
Iraq Ministry of Oil	2,460	0	2,460	State-owned	Iraq
Oil and Natural Gas Corporation	2,333	0	2,333	Private	India
Total S.A.	871	1,444	2,315	Private	France
Government of Kenya	1,799	446	2,245	State-owned	Kenya
Türkmengaz	300	1,814	2,114	State-owned	Turkmenistan
Pertamina	1,611	443	2,054	Private	Indonesia
Sonatrach	1,724	0	1,724	State-owned	Algeria
Indian Oil Corporation Limited	513	1,205	1,718	State-owned	India

Source: Global Fossil Infrastructure Tracker, January 2019

Table 6. The Top 20 North American Builders of Oil and Gas Pipelines (by km)

Owner	Proposed	Construction	Total	Ownership	Country
TransCanada	4,530	1,311	5,841	Private	Canada
Kinder Morgan	1,304	2,962	4,266	Private	U.S.
Alaska Gasline Development Corporation	3,888	0	3,888	State-owned	U.S.
Plains GP Holdings	2,627	628	3,255	Private	U.S.
Eagle Spirit Energy Holdings	1,601	0	1,601	Private	Canada
Tellurian Inc.	1,482	0	1,482	Private	U.S.
Williams Companies	1,437	17	1,454	Private	U.S.
Energy Transfer TP	0	1,341	1,341	Private	U.S.
Tallgrass Energy	1,304	0	1,304	Private	U.S.
Targa Resources	998	191	1,189	Private	U.S.
Sempra Energy	677	400	1,077	Private	U.S.
Magnum Development	1,046	0	1,046	Private	U.S.
Phillips 66	1,030	0	1,030	Private	U.S.
Canada Development Investment Corporation	980	0	980	State-owned	Canada
Dominion Energy	622	241	863	Private	U.S.
Fairbanks Pipeline Company	827	0	827	Private	U.S.
Fermaca	161	664	825	Private	Mexico
Comisión Federal de Electricidad	0	780	780	State-owned	Mexico
ExxonMobil	698	77	775	Private	U.S.
Magellan Midstream Partners	604	121	724	Private	U.S.

Source: Global Fossil Infrastructure Tracker, January 2019

THE PERFECT STORM

The short-term outlook for fossil fuel investors in North America may seem rosy, with large plays such as the Permian and Marcellus undergoing development, gas replacing coal in many markets, and the Trump administration advocating for more offshore drilling. A storm is coming, however, and the current surge in pipeline construction may prove to be fleeting as the legal system, public opinion, and financial markets increasingly challenge the fossil fuel industry.

Legal Obstacles: In 2016 the Obama Administration established a rule that applications to the Federal Energy Regulatory Commission (FERC) must include an assessment of a pipeline's or other project's impact on climate change. Given that FERC rejected just two out of 400 pipelines applications it received between 1999 and 2017, this new rule could have seismic implications (Horn 2017). With a majority of its five commissioners now serving as Trump appointees, FERC has taken a "see no evil" approach to findings submitted under this rule; for example, when a study found that the proposed Sabal Trail pipeline from Alabama to Florida would increase Florida's rate of greenhouse gas emissions by between 3.6% and 9.9%, FERC approved the project on the grounds that such an increase was not significant. However this rule may be interpreted in the future, the principle that projects must justify their existence in terms of their emissions is taking root in the legal community. In March 2019 a U.S. District Judge blocked the leasing of 500 square miles for drilling in Wyoming on the grounds that the U.S. Bureau of Land Management had not considered the impact of emissions from oil and gas leases nationwide. "This is the Holy Grail ruling we've been after, especially with oil and gas," said Jeremy Nichols of WildEarth Guardians, which sued to block the leases. "It calls into question the legality of oil and gas leasing that's happening everywhere." (Brown and Mead 2019)

Shifting Public Opinion: American public opinion is also turning against the fossil fuel industry. A January 2019 poll by Yale University and George Mason University found that 69% of Americans are "worried" about climate change and 29% are "very worried." This represents an 8% rise among those who are "very worried" since these pollsters' previous survey in April 2018. The shift in public opinion comes as more Americans are personally affected by climate change, from historically-devastating fires in California to catastrophic floods in places such as Houston, Texas and the Carolinas.

Shifting Economics: The world for which many North American pipelines are being built may no longer exist by the time they are completed. Because of their typical lifespans of 40 years or more, pipeline projects and their sponsors tend to be highly leveraged, with long payback periods. For example, as of late 2018 one analyst reported that Enbridge expected to end 2018 with a leverage ratio of 5.0 times debt to EBITDA (earnings before interest, taxes, depreciation, and amortization)—"a bit higher than its comfort zone"—not including a "massive slate" of $16.7 billion in additional pipeline projects (DiLallo 2018).

High Leverage and Unrealistic Expectations: The combination of high leverage and expectations for growth based on ever-increasing Asian demand set the stage for investor disappointment and losses. Such a possibility is not just hypothetical: it is exactly the combination of elements that created the coal mining meltdown of 2008 to 2014, as discussed in the sidebar, "The Coal Mining Equities Crash." While the crash of the coal mining industry cost investors tens of billions, a similar stumble in the oil and gas industry has much larger implications because of the larger size of the sector. At their peak in 2011, the combined equity value of the coal mining sector amounted to about $80 billion; by mid-2015 that value had dropped about $12 billion, a $68 billion loss (Coats 2015). In contrast, the amount of capital expenditure on pipelines alone is expected to be well over $200 billion over the coming decades, out of a total midstream oil and gas infrastructure investment of $1 trillion for the U.S. alone. The combination of large financial sums at stake, excess enthusiasm based on uncertain overseas markets, and growing social stigmatization are all factors that should cause both individual and institutional investors to turn away from further bets on pipelines and other midstream infrastructure investments.

METHODOLOGY

The Global Fossil Infrastructure Tracker uses a two-level system for organizing information. Summary data is maintained in Google sheets, with each spreadsheet row linked to a page on the SourceWatch wiki. Each wiki page functions as a footnoted fact sheet, containing project parameters, background, and mapping coordinates. Each worksheet row tracks an individual pipeline project. Under standard wiki convention, each piece of information is linked to a published reference, such as a news article, company report, or regulatory permit. In order to ensure data integrity in the open-access wiki environment, Global Energy Monitor researchers review all edits of project wiki pages by unknown editors. For each project, one of the following status categories is assigned and reviewed on a rolling basis:

- **Proposed:** Projects that have appeared in corporate or government plans in either pre-permit or permitted stages.
- **Construction:** Site preparation and other development and construction activities are underway.
- **Shelved:** In the absence of an announcement that the sponsor is putting its plans on hold, a project

is considered "shelved" if there are no reports of activity over a period of two years.

- **Cancelled:** In some cases a sponsor announces that it has cancelled a project. More often a project fails to advance and then quietly disappears from company documents. A project that was previously in an active category is moved to "Cancelled" if it disappears from company documents, even if no announcement is made. In the absence of a cancellation announcement, a project is considered "cancelled" if there are no reports of activity over a period of four years.
- **Operating:** The pipeline has been formally commissioned or has entered commercial operation.
- **Mothballed:** Previously operating projects that are not operating but maintained for potential restart.
- **Retired:** Permanently closed projects.

To allow easy public access to the results, Global Energy Monitor worked with GreenInfo Network to develop a map-based and table-based interface using the Leaflet Open-Source JavaScript library. The public view of the Global Fossil Infrastructure Tracker can be accessed at OilWire.org.

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The New Gas Boom

TRACKING GLOBAL LNG INFRASTRUCTURE

Ted Nace, Lydia Plante, and James Browning

ABOUT THE COVER

LNG tanker Energy Progress taking on cargo at Darwin LNG Terminal, Northern Territory, Australia, in March 2016. © 2016 by Ken Hodge. Creative Commons Attribution 2.0 license at http://bit.ly/2KGIT5e.

ABOUT GLOBAL ENERGY MONITOR

Global Energy Monitor (formerly CoalSwarm) is a network of researchers developing collaborative informational resources on fossil fuels and alternatives. Current projects include the Global Coal Plant Tracker, the Global Fossil Infrastructure Tracker, the CoalWire newsletter, and the CoalSwarm and FrackSwarm wiki portals.

ABOUT THE GLOBAL FOSSIL INFRASTRUCTURE TRACKER

The Global Fossil Infrastructure Tracker is an online database that identifies, maps, describes, and categorizes oil and gas pipelines and oil, gas, and coal terminals. Developed by Global Energy Monitor, the tracker uses footnoted wiki pages to document each plant. For further details, see “Methodology” at http://ggon.org/fossil-tracker/

AUTHORS

Ted Nace is Executive Director of Global Energy Monitor. Lydia Plante is Researcher and Analyst at Global Energy Monitor. James Browning is Communications Director at Global Energy Monitor.

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FURTHER RESOURCES

For additional data on proposed and existing pipelines, Summary Data at http://ggon.org/fossil-tracker/ provides over 50 tables compiled from the Global Fossil Infrastructure Tracker (GFIT), broken down by nation and region. To obtain primary data from the GFIT, contact Ted Nace (ted@tednace.com).

Global Energy Monitor

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TRACKING GLOBAL LNG INFRASTRUCTURE

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EXECUTIVE SUMMARY

Through a massive increase in portside infrastructure, floating offshore terminals, and oceangoing LNG vessels, the natural gas industry is seeking to restructure itself from a collection of regional markets into a wider and more integrated global system. If successful, this transformation would lock in much higher levels of natural gas production through mid-century—a seeming win for the industry—except that the falling cost of renewable alternatives will make many of these projects unprofitable in the long term and put much of the $1.3 trillion being invested in this global gas expansion at risk. Such an expansion is also incompatible with the IPCC's warning that, in order to limit warming to 1.5°C above pre-industrial levels, gas use must decline 15% by 2030 and 43% by 2050, relative to 2020.

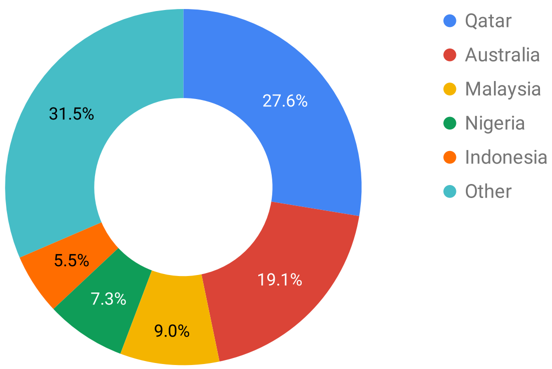
This report provides the results of a worldwide survey of LNG terminals completed by the Global Fossil Infrastructure Tracker. The report includes the following highlights:

- Methane, the chief component in natural gas, is responsible for 25% of global warming to date.
- Measured by global warming impacts, the scale of the LNG expansion under development is as large or greater than the expansion of coal-fired power plants, posing a direct challenge to Paris climate goals.
- Due to falling costs of renewable alternatives, the expansion of LNG infrastructure faces questions of long-term financial viability and stranded asset risk. However, since only 8% of terminal capacity under development has entered construction, there is still time to avoid overbuilding.
- At least 202 LNG terminal projects are in development worldwide, including 116 export terminals and 86 import terminals.
- LNG export terminals are under development in 20 countries, of which Canada and the U.S. account for 74% of proposed new capacity. If built, LNG terminals in pre-construction and construction would increase current global export capacity threefold.
- LNG import terminals are in development in 42 countries, of which 22 have no current import capacity. Capacity expansion is focused on the Asia Pacific Region.
- Overall, LNG terminals in development represent capital outlays of $1.3 trillion, of which 70% is for North American export terminals and 6% is for Asia Pacific import terminals. In terms of capital outlays for import and export terminals combined, the top ten countries are United States ($507 billion), Canada ($410 billion), Russia ($86 billion), Australia ($38 billion), Tanzania ($25 billion), China ($24 billion), Indonesia ($24 billion), Mozambique ($23 billion), Iran ($21 billion), and Papua New Guinea ($17 billion).

THE GROWING ROLE OF LNG IN NATURAL GAS MARKETS

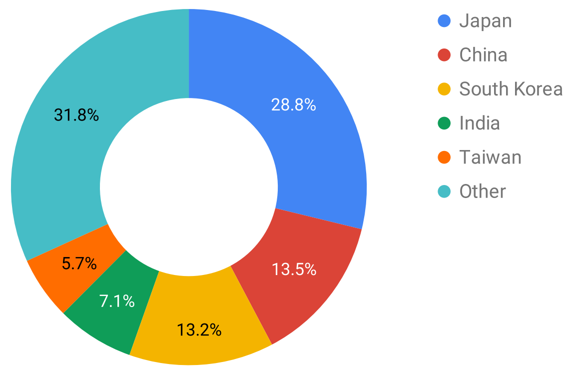
Historically, most natural gas was transported by pipeline within regions, with a small fraction (5.5% in 2000) transported by ship as liquified natural gas (LNG), mainly from a handful of producing countries (led by Qatar and Australia) to a handful of importing countries (led by Japan, China, and South Korea). In the case of both imports and exports, just five exporting and five importing countries accounted for two-thirds of the global LNG trade in 2017, as shown in Figures 1 and 2. Since 2000, the share of LNG in the global system has doubled to 11%, with 432 billion cubic meters of LNG in 2018 out of total global natural gas production of 3,940 bcm (IEA 2019).

Figure 1. Shares of LNG Exports for Top Five Countries, 2017



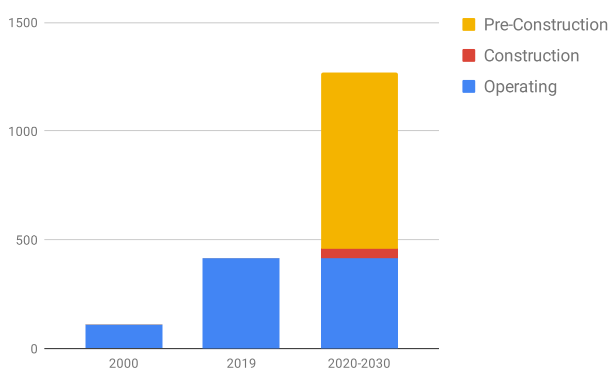
Source: International Gas Union, 2018

Figure 2. Shares of LNG Imports for Top Five Countries, 2017



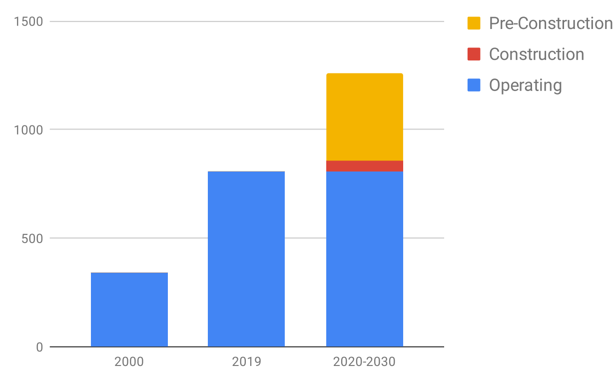
Source: International Gas Union, 2018

Figure 3. LNG Export Capacity in 2000, 2019, and in Development



Source: Global Fossil Infrastructure Tracker, April 2019

Figure 4. LNG Import Capacity in 2000, 2019, and in Development



Source: Global Fossil Infrastructure Tracker, April 2019

TOWARD A NORTH AMERICA–CENTERED, GLOBALLY INTEGRATED NATURAL GAS SYSTEM

As shown in Figure 3, projects currently under construction or in pre-construction would more than triple global export capacity. If fully implemented, current proposals will raise the share of LNG in overall gas production to 20% by 2030, assuming sector growth in line with the IEA New Policies Scenario (IEA 2018).

Besides growing in market share, LNG is also growing in geographic scope to include more producing and recipient countries. Together, the two developments are shifting the global gas system to a more globally integrated system connected by shipborne LNG cargoes.

Although some new LNG export capacity is under development in 20 countries, as shown in Table 2, the vast majority is concentrated in North America, including 352.7 million tonnes per annum (MTPA) under development in the U.S. and 281.6 MTPA under development in Canada, or 74% of all export capacity in development globally.

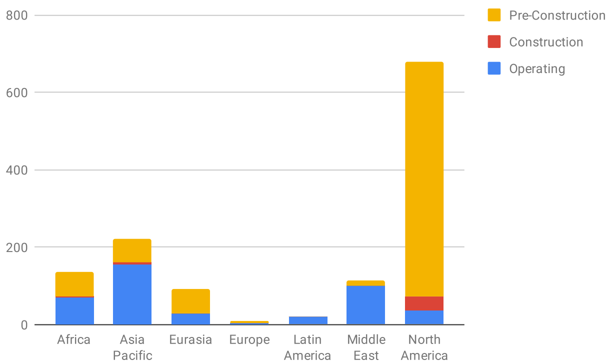
As shown in Figure 4 and Table 1, expansion of LNG import capacity is more widely distributed, including 65.6 million tonnes per annum of new capacity in 22 countries that currently have no import capacity. Overall, projects under development would increase the number of countries with LNG import capacity from 40 to 62.

Table 1. LNG Importing Countries, 2000, 2019, and 2030 (projects in development shown in red)

Year	Countries
2000	Belgium, France, Greece, Italy, Japan, South Korea, Spain, Taiwan, Turkey, USA
2019	Argentina, Bangladesh, Belgium, Brazil, Canada, Chile, China, Colombia, Dominican Republic, Finland, France, Greece, India, Indonesia, Israel, Italy, Jamaica, Japan, Jordan, Kuwait, Lithuania, Malaysia, Malta, Mexico, Netherlands, Pakistan, Panama, Poland, Portugal, Russia, Singapore, South Korea, Spain, Sweden, Taiwan, Thailand, Turkey, United Arab Emirates, United Kingdom, USA
2030	Argentina, **Australia**, **Bahrain**, Bangladesh, Belgium, Brazil, Canada, Chile, China, Colombia, **Croatia**, **Cyprus**, Dominican Republic, Finland, **Egypt**, **Estonia**, France, **Germany**, **Ghana**, Greece, **Haiti**, India, Indonesia, **Ireland**, Israel, Italy, Jamaica, Japan, Jordan, **Kenya**, Kuwait, Lithuania, Malaysia, Malta, Mexico, **Morocco**, **Myanmar**, **Namibia**, Netherlands, **Nigeria**, Pakistan, Panama, **Philippines**, Poland, Portugal, **Romania**, Russia, Singapore, **South Africa**, South Korea, Spain, **Sri Lanka**, Sweden, Taiwan, Thailand, Turkey, United Arab Emirates, **Ukraine**, United Kingdom, USA, **Uruguay**, **Vietnam**

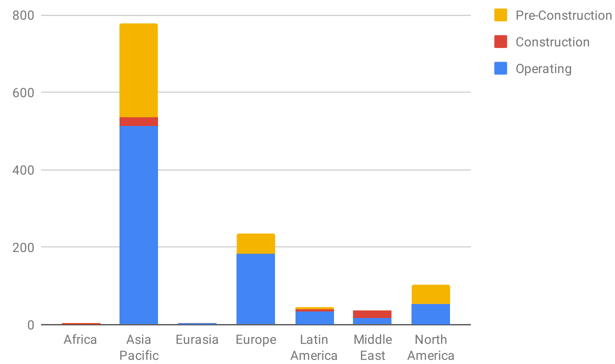
Source: Global Fossil Infrastructure Tracker, April 2019

Figure 5. LNG Export Capacity by Region and Developmental Status, 2019 (million tonnes per annum)



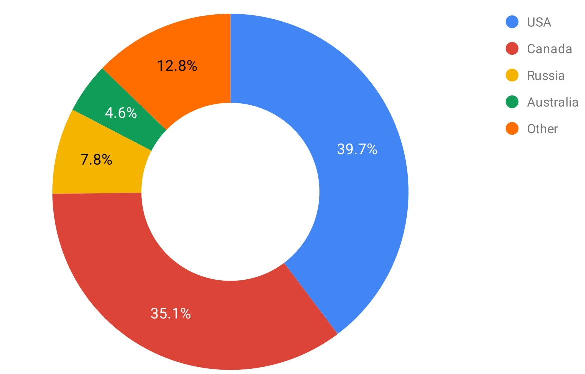
Source: Global Fossil Infrastructure Tracker, April 2019

Figure 6. LNG Import Capacity by Region and Developmental Status, 2019 (million tonnes per annum)



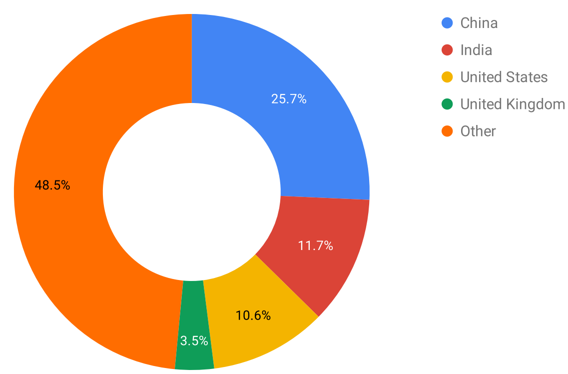
Source: Global Fossil Infrastructure Tracker, April 2019

Figure 7. LNG Export Capacity in Development (Pre-Construction and Construction), 2019, Top Four Countries



Source: Global Fossil Infrastructure Tracker, April 2019

Figure 8. LNG Import Capacity in Development (Pre-Construction and Construction), 2019, Top Four Countries



Source: Global Fossil Infrastructure Tracker, April 2019

Table 2. LNG Export (Liquefaction) and Import (Regasification) Capacity by Country and Developmental Status (million tonnes per annum), 2019

	Export Terminals			Import Terminals		
Country	Operating	Construction	Pre-Construction	Operating	Construction	Pre-Construction
Algeria	25.3	0.0	4.0	0.0	0.0	0.0
Angola	5.2	0.0	0.0	0.0	0.0	0.0
Argentina	0.0	0.0	0.0	7.8	0.0	0.0
Australia	83.2	0.0	36.7	0.0	0.0	5.2
Bahrain	0.0	0.0	0.0	0.0	6.1	0.0
Bangladesh	0.0	0.0	0.0	5.0	3.5	7.5
Belgium	0.0	0.0	0.0	9.0	0.0	0.0
Brazil	0.0	0.0	0.0	8.9	3.6	0.0
Brunei	7.2	0.0	0.0	0.0	0.0	0.0
Cameroon	2.4	0.0	0.0	0.0	0.0	0.0
Canada	0.0	0.0	281.6	21.2	0.0	11.0
Chile	0.0	0.0	0.0	5.3	3.3	1.4
China	0.0	0.0	0.0	73.2	8.6	78.5
Colombia	0.0	0.0	0.0	3.0	0.0	0.0
Croatia	0.0	0.0	0.0	0.0	0.0	1.5
Cyprus	0.0	0.0	5.0	0.0	0.0	1.3
Dominican Republic	0.0	0.0	0.0	1.9	0.0	0.0
Egypt	12.2	0.0	0.0	0.0	0.0	0.0
Equatorial Guinea	3.7	0.0	8.8	0.0	0.0	0.0
Estonia	0.0	0.0	0.0	0.0	0.0	4.5
Finland	0.0	0.0	0.0	1.6	0.1	0.0
France	0.0	0.0	0.0	27.8	0.0	0.0
Germany	0.0	0.0	0.0	0.0	0.0	11.0
Ghana	0.0	0.0	0.0	0.0	3.4	0.0
Greece	0.0	0.0	0.0	7.7	0.0	0.0
India	0.0	0.0	0.0	49.0	10.0	29.5
Indonesia	26.5	4.3	11.0	8.9	0.0	7.8
Iran	0.0	0.0	13.3	0.0	0.0	0.0
Ireland	0.0	0.0	0.0	0.0	0.0	2.0
Israel	0.0	0.0	0.0	3.7	0.0	0.0
Italy	0.0	0.0	0.0	11.7	0.0	3.5
Jamaica	0.0	0.0	0.0	4.8	0.0	2.5
Japan	0.0	0.0	0.0	219.7	0.0	11.7
Jordan	0.0	0.0	0.0	5.5	0.0	0.0
Kenya	0.0	0.0	0.0	0.0	0.0	0.3
Kuwait	0.0	0.0	0.0	9.6	11.3	0.0
Lithuania	0.0	0.0	0.0	2.2	0.0	0.0
Malaysia	30.5	1.5	0.0	7.3	0.0	0.0

Table 2 (continued)

	Export Terminals			Import Terminals		
Country	**Operating**	**Construction**	**Pre-Construction**	**Operating**	**Construction**	**Pre-Construction**
Malta	0.0	0.0	0.0	0.4	0.0	0.0
Mexico	0.0	0.0	7.0	16.1	0.0	0.0
Mozambique	0.0	3.4	12.0	0.0	0.0	0.0
Myanmar	0.0	0.0	0.0	0.0	0.0	4.0
Netherlands	0.0	0.0	0.0	9.0	0.0	0.0
Nigeria	21.9	0.0	10.0	0.0	0.0	0.0
Norway	4.5	0.0	0.0	0.0	0.0	0.0
Oman	10.8	0.0	0.0	0.0	0.0	0.0
Pakistan	0.0	0.0	0.0	14.5	0.0	4.5
Panama	0.0	0.0	0.0	1.5	0.0	0.0
Papua New Guinea	6.9	0.0	14.0	0.0	0.0	0.0
Peru	4.5	0.0	0.0	0.0	0.0	0.0
Philippines	0.0	0.0	0.0	0.0	1.5	0.0
Poland	0.0	0.0	0.0	3.7	0.0	1.8
Portugal	0.0	0.0	0.0	6.0	0.0	0.0
Qatar	77.0	0.0	0.0	0.0	0.0	0.0
Romania	0.0	0.0	0.0	0.0	0.0	6.0
Russia	28.0	2.0	62.6	2.7	0.0	0.0
Senegal	0.0	0.0	2.5	0.0	0.0	0.0
Singapore	0.0	0.0	0.0	11.0	0.0	5.3
South Africa	0.0	0.0	0.0	0.0	0.0	1.6
South Korea	0.0	0.0	0.0	101.8	0.0	3.6
Spain	0.0	0.0	0.0	46.0	0.0	2.0
Sri Lanka	0.0	0.0	0.0	0.0	0.0	2.7
Sweden	0.0	0.0	0.0	0.4	0.0	0.0
Taiwan	0.0	0.0	0.0	12.0	0.0	7.8
Tanzania	0.0	0.0	20.0	0.0	0.0	0.0
Thailand	0.0	0.0	0.0	10.0	0.0	9.0
Trinidad and Tobago	15.5	0.0	0.0	0.0	0.0	0.0
Turkey	0.0	0.0	0.0	19.4	0.0	0.0
Ukraine	0.0	0.0	0.0	0.0	0.0	7.3
United Arab Emirates	5.8	0.0	0.0	4.0	0.0	0.0
United Kingdom	0.0	0.0	0.0	35.0	0.0	12.0
Uruguay	0.0	0.0	0.0	0.0	0.0	0.1
USA	37.3	34.3	318.4	17.6	0.0	36.0
Vietnam	0.0	0.0	0.0	0.0	0.0	4.6
Yemen	7.2	0.0	0.0	0.0	0.0	0.0
Total	**415.5**	**45.5**	**806.9**	**805.9**	**51.4**	**287.5**

Source: Global Fossil Infrastructure Tracker, April 2019.

EXPORT INFRASTRUCTURE IS THE FOCUS OF THE EXPANSION

Global LNG export capacity is smaller than global LNG import capacity, and utilization rates are higher than for LNG import terminals. This means that LNG export capacity is the limiting factor in the growth of global LNG usage, particularly from North American fracked gas production. In 2018, average utilization rates were 79% for export terminals and 40% for import terminals. Since existing export capacity is rarely idle, significant growth in LNG exports will not be possible without building new LNG export terminal capacity.

As shown in Table 3, import terminal capacity under development is heavily concentrated in the Asia Pacific region, led by China with 87.1 million tonnes per annum (MTPA) and India with 39.5 MTPA, as shown in Table 2. The leading importer, Japan, has comparatively modest expansion plans, with only 11.7 MTPA in development.

CAPITAL COSTS: $1.3 TRILLION

The capital expenditures required for LNG terminals in development amount to $1.3 trillion globally and are overwhelmingly concentrated in North America, where $914.5 billion in export terminals are development, representing 70% of the global total. As shown in Table 3, export terminals dominate proposed expenditures, for two reasons. First, a larger amount of export capacity is currently under development globally. Second, on a tonne-for-tonne basis, the liquefaction process at export terminals is more expensive than the regasification process at import terminals, due to the massive cooling and pressurization processes required for liquefaction. The International Gas Union estimates capital costs for export terminals at $1,501 per tonne of annual capacity for greenfield projects and $458 per tonne for brownfield projects; IGU estimates capital costs for import terminals projects at $274 per tonne (IGU 2018).

Table 3. Capital Investments for LNG Export (Liquefaction) and Import (Regasification) Terminals Under Development (Billion US$)

Region	Export	Import	Total
Africa	85.0	1.4	86.5
Asia Pacific	75.5	73.2	148.7
Eurasia	85.6	0.0	85.6
Europe	7.5	14.2	21.7
Latin America	0.0	3.0	3.0
Middle East	21.0	4.8	25.8
North America	914.5	12.9	927.4
Total	**1,189.2**	**109.4**	**1,298.6**

Sources: Capacity estimates from Global Fossil Infrastructure Tracker, April 2019; Capital costs from IGU 2018.

STRANDED ASSET RISK

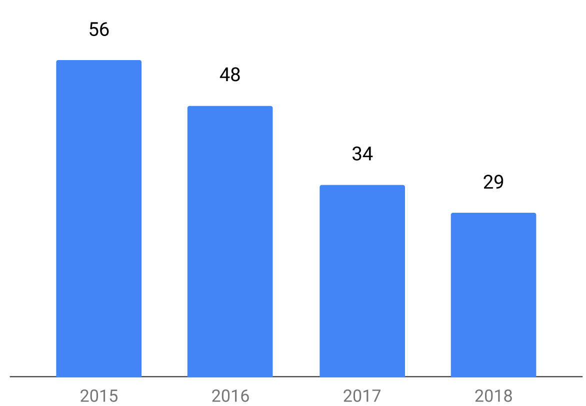
Despite its price tag ($1.3 trillion) and its role in the climate crisis, the expansion of LNG infrastructure has received relatively little scrutiny in terms of stranded asset risk. But attention to stranded asset issues is rising due to increased cost pressure on natural gas by renewable alternatives. In its 12th annual levelized cost of energy study, Lazard Bank reported that unsubsidized solar PV is now cheaper or comparable in cost to natural gas peaking power in all economies studied, including the U.S., Australia, Brazil, India, South Africa, Japan, and Northern Europe. Similarly, wind power is now cheaper or comparable in cost to combined cycle gas turbines across the same set of countries (Lazard 2018). A 2018 study by Rocky Mountain Institute concluded that U.S. power system portfolios built around renewables and distributed energy resources will offer the same grid reliability at lower cost as gas generators by 2026 at gas prices of $5 per million Btu, or by 2040 at $3 per million Btu. Such a shift would place hundreds of billions of dollars of relatively new gas plants in jeopardy of becoming stranded assets (Dyson 2018). To the extent that new LNG terminals are relying on power sector demand, that infrastructure is also at risk of underutilization.

As an example of how competitive renewables are fundamentally changing the power industry, falling orders for natural gas turbines have dramatically impacted the market value of power equipment manufacturer General Electric, which has declined in value from over $350 billion in 2007 to under $90 billion in 2019, including a $23 billion write-down on its investment in the power and grid division of Alstom. According to one analysis, "While financial leverage drove the collapse of GE's value over 2016–2018, the trigger was the halving of global thermal power sector demand." (Buckley 2019a) Figure 10 shows the decline in worldwide orders for gas turbines that drove the fall in GE's market value.

The financial shocks now being experienced in the natural gas sector are reminiscent of similar patterns in the coal sector, where euphoric forecasts of growth based on East Asian demand a decade ago led to overexpansion and financial collapse. In 2010, Peabody Energy Chairman Gregory Boyce predicted that rising demand in China and China's neighboring economies would create "a long-term super-cycle for coal." (Schmidt 2010.) Yet in a relatively short time span, 2011 to 2016, falling coal prices and competitive alternatives forced Peabody Energy along with most other major American coal companies to file for Chapter 11 protection (Nace 2019).

The sort of instability that has afflicted the coal sector similarly threatens the long-term financial viability of fracked gas. As with coal, capital investments in the gas sector must be made under conditions of inherent uncertainty about key factors such as the rate of decline in the cost of renewables and the level of climate regulation a decade in the future. For natural gas, the fact that fracking remains a relatively new practice whose long-term economics are still not well understood adds yet another dimension of risk. After a cross-section of 29 fracking-focused companies found more than $2.5 billion in negative free cash flows in the first quarter of 2019, raising the aggregate negative cash flow from fracking to $184 billion since 2010, analysts at Sightline Institute and the Institute for Energy Economics and Financial Analysis concluded that negative cash flows appeared to be chronic and "should be of grave concern to investors." The analysts wrote, "Until fracking companies can demonstrate that they

Figure 9. Gas Turbine Industry Orders (gigawatts)



Source: GE 2018 Annual Report. Includes turbines 30 megawatts and larger.

can produce cash as well as hydrocarbons, cautious investors would be wise to view the fracking sector as a speculative enterprise with a weak outlook and an unproven business model." (Williams-Derry, 2019.)

Compounding questions of financial risk are widening concerns about the impact of natural gas on global warming. As detailed in the sidebar "Hero to Villain," the perception of gas, especially when produced by fracking and shipped as LNG, has shifted in recent years due to several new findings:

- Estimates of the level of fugitive emissions have risen.
- Estimates of the potency of methane as a global warming gas have also risen.
- Fracked gas, with approximately 50% higher fugitive emissions than conventional natural gas, now dominates the production mix in North America.
- Due to the additional energy demands and opportunities for fugitive emissions involved in liquefaction, shipborne transport, and regasification, LNG is seen as particularly damaging to climate stability.
- In its most recent reports, the IPCC has called for near-term reduction in natural gas production of 15% by 2030 and 43% by 2050, relative to 2020 (see Table 5). Such reductions are not compatible with expansion of the current natural gas system, including the building of new LNG capacity.

METHANE AS A GLOBAL WARMING GAS: 7 KEY NUMBERS

As described in the sidebar, "Hero to Villain: Changing View of Natural Gas," the perception of the benefit or harm of natural gas in a climate-constrained energy system has shifted over the past decade from positive to negative, as climate scientists measure with increasing accuracy the level of leakage throughout the natural gas supply and delivery system and the potency of methane as a global warming gas. While carbon dioxide plays a larger role than methane in global warming, a number of recent findings indicate that the role of methane is larger than previously thought. Seven key numbers illustrate the shift in understanding.

Table 4. Seven Key Methane Numbers

700	In the pre-industrial era, the level of gas was about 700 parts per billion (NASA 2016).
1,850	In 2018, climate scientists reported that atmospheric methane had risen from 1,775 parts per billion in 2006 to 1,850 ppb in 2017 and was growing at an accelerating rate. The rapid growth, which had not been expected, "is sufficient to challenge the Paris Agreement." (Nisbet 2017)
25%	The percentage of global warming to date caused by methane (Myhre 2014).
2.3%	In 2018, a major peer-reviewed study estimated that the leakage rate for the U.S. gas system was 2.3%. The estimate was 60% higher than the figure previously used by the U.S. government in major assessments of natural gas (Alvarez 2018).
86	Compared to carbon dioxide (CO_2), methane (CH_4) is a relatively short-lived but highly potent global warming gas, which remains in the atmosphere for only a decade but during that time has more than 100 times as much effect on global warming as carbon dioxide. Considered over a 20-year horizon, methane's global warming impact is 86 times that of carbon dioxide, according to the most recent IPCC assessment (Myhre 2014).
34	Considered over a 100-year horizon, methane's global warming impact is 34 times that of carbon dioxide, according to the most recent IPCC assessment (Myhre 2014).
25%	In 2016 the authors of the IPCC's 2014 assessment concluded that methane's impact on global warming is about 25% higher than previously estimated, further raising concerns (Etminan 2016).

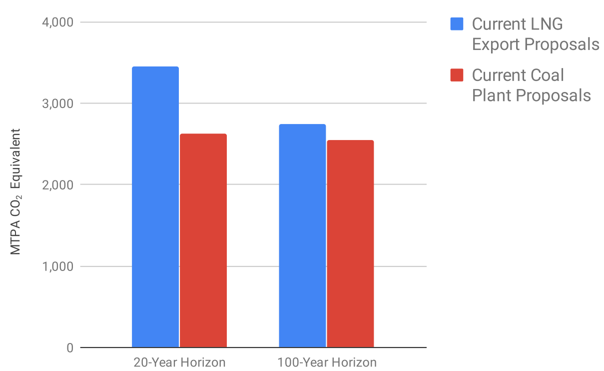
WORSE THAN THE COAL BOOM: MEASURING THE CARBON FOOTPRINT OF THE LNG BOOM

To assess the global warming footprint of the LNG terminal boom, we can compare it to another boom: the expansion of global coal-fired generating capacity. Both expansions involve the construction of massive new facilities with life expectancies of four decades or more.

Currently, over 579 gigawatts (GW) of coal power capacity is under construction or in pre-construction (Shearer 2019). In order to compare that to the 856 million tonnes per year of LNG export capacity under construction or in pre-construction, we need to examine both expansions on the basis of lifecycle emissions for both CO_2 and methane, including all stages from mining or drilling through final consumption. That analysis is detailed in Appendix B. It uses a common basis for comparison known as "CO_2 equivalency" or CO_2e. Since methane (CH_4) in natural gas lasts for only about a decade, but during time has over 100 times the global warming potency of CO_2, determining CO_2e requires that the analysis specify the time horizon over which the global warming averages are being averaged. Analyses of methane typically use two alternative comparisons, one over a 20-year period, the other over a 100-year period. The 20-year horizon is relevant for understanding how greatly methane emissions will affect the climate in the short term; the 100-year horizon is relevant for understanding the long-term effect on climate.

The results of the lifecycle comparison, including fugitive methane emissions, show that current proposals for new LNG terminal capacity, if fully developed, would lock in global warming impacts that are roughly equivalent, when considered on a 100-year horizon, to those of current proposals for new coal-fired power plants. These proposals amount to 574 GW of new coal-fired generating capacity, or 1,214 generating units (Global Coal Plant Tracker, January 2019). When considered on a 20-year horizon, the global warming impact of current proposals for new LNG terminals exceed current proposals for new coal-fired plants by 25%.

Figure 10. Comparing the Life Cycle Global Warming Footprint of Proposed Expansion of LNG-Transported Natural Gas (856.4 MTPA) to the Life Cycle Global Warming Footprint of Proposed Coal Plants, (574 GW). Both Life Cycle estimates in Million Tonnes Per Annum CO_2 Equivalent.



Based on Global Coal Plant Tracker (January 2019) and Global Fossil Infrastructure Tracker (April 2019). For details, see Appendix A.

HERO TO VILLAIN: CHANGING VIEWS OF NATURAL GAS

"With the move to natural gas, it's as if we proudly announced we kicked our Oxycotin habit by taking up heroin instead." —Bill McKibben

Because power plant combustion of natural gas produces about 40% less carbon dioxide than combustion of coal, proponents of natural gas have characterized it as a "bridge" from coal to renewables (Oil Change International 2017, Sightline 2019). However, a full life cycle comparison of both natural gas and coal requires also including the effect of leakages in natural gas production and transportation, since methane (CH_4), the main component of natural gas, is a far more powerful global warming gas than carbon dioxide.

Early life cycle comparisons favor gas. A milestone in addressing the full life cycle impacts of natural gas was the U.S. Department of Energy's 2014 report "Life Cycle Greenhouse Gas Perspectives on Exporting Liquefied Natural Gas from the United States." That report showed lower life cycle greenhouse gas impacts from exporting LNG to overseas power plants than from burning domestic coal (U.S. Department of Energy, 2014).

Updated leakage estimates alter the assessment. The 2014 DOE report was based on the assumption that methane leakage was 1.3% for conventional onshore gas and 1.4% for fracked gas. In 2018, a comprehensive reassessment of methane emissions in the U.S. oil and gas supply chain, based on facility-scale measurements and validated with aircraft observations in areas accounting for about 30% of U.S. gas production, concluded that the overall leakage rate for natural gas was 2.3% of gross U.S. gas production, a figure 60% higher than the U.S. Environmental Protection Agency inventory estimate (Alvarez 2018). At the higher leakage rate, the advantage to using coal disappears. Multiple studies estimate the overall leakage rates even higher than the 2.3% Alvarez estimate, due to the fact that the Alvarez study did not include "downstream" leaks in the distribution of gas. Such leaks account for an additional 2.7 ± 0.6%, according to a study of Boston (McKain 2015).

Fracked gas versus conventional gas. Side-by-side comparisons of conventionally produced gas and gas produced by fracking indicate that fracked gas, also known as "unconventional" gas, is associated with approximately 50% great leakages than conventional gas (Brandt 2014). From 2000 to 2015, the share of fracked gas in U.S. production went from less than 5% to 67%, and continues to rise (US EIA 2016). With the greater share of fracked gas in the overall mix, the relative level of fugitive emissions has correspondingly risen.

Adding shortwave effects shows even more harm from methane. More recently, the authors of the IPCC findings issued a significant revision in their estimate of the relative ratios that incorporated new findings based on the inclusion of shortwave climate forcing. The new findings raise estimates of methane's climate impact relative to carbon dioxide by about 25% (Etminan 2016).

20-Year or 100-Year? Methane has a residence time in the atmosphere of only a decade, but while present its greenhouse warming effect is more than 100 times that of carbon dioxide, on a mass-to-mass basis (Howarth 2015). Averaged over a 20-year time period, the ratio between methane and carbon dioxide, including climate-carbon feedbacks, is 86:1; over a 100-year time period the ratio including climate-carbon feedbacks is 34:1, according to the Intergovernmental Panel on Climate Change (IPCC 2014).

Additional considerations. Increasingly, climate advocates have pointed out that the debate over whether coal or gas is worse from a climate perspective misses a larger point, namely, that according to the most findings of the IPCC, the entire global system must decarbonize by 2050 (Stockman 2019). Replacing old coal infrastructure with new gas infrastructure will lock in a fossil-based system, effectively resetting the clock on system transformation by another 40 or more years. Such a result is incompatible with the mandate that fossil emissions be phased out by mid-century.

IPCC 1.5˚ findings. The October 2018 report of the IPCC, "Global Warming of 1.5°C," brought new urgency to the need for fossil fuel reductions. As shown in Table 5, which is based on pathways that would allow a 1-in-2 to 2-in-3 chance of limiting global warming to 1.5°C above pre-industrial levels, gas must decline 15% by 2030 and 43% by 2050, relative to 2020.

Table 5. Median primary energy supply (Exajoules) for below IPCC 1.5°C pathways with low overshoot.

	2020	2030	2050
Gas	132.95	112.51	76.03

Source: IPCC, "Global Warming of 1.5°C," Table 2.6, October 2018

CONCLUSION: A MORATORIUM IS NEEDED ON NEW LNG CONSTRUCTION

As shown in Table 2, plans for LNG export terminals includes 45.5 MTPA in projects under construction and 806.9 MTPA in pre-construction projects; for LNG import terminals, plans include 51.4 MTPA in projects under construction and 349.3 MTPA in pre-construction projects. As shown in Table 6, which reflects only projects with known dates and does not account for schedule slippage, a large amount of capacity has announced dates prior to 2026 and may be close to entering construction. Given the climate mandate that natural gas be scaled back over the next decade, not to mention the risk to investors of stranded assets and financial losses from overbuilding, a sensible approach to the question of LNG terminal expansion would be a moratorium on further construction.

Table 6. LNG Terminal Projects in Pre-Construction, including Export and Import, by Announced Start Year (million tonnes per annum)

Start Year	MTPA
2019	99
2020	71
2021	69
2022	162
2023	63
2024	58
2025	112
2026	37
2027	21
2028	0
2029	0
2030	20
Total	**712**

Source: Global Fossil Infrastructure Tracker, April 2019

APPENDIX A. THE COAL MINING EQUITIES CRASH

On April 13, 2016, the largest U.S. coal company, Peabody Energy, declared bankruptcy. By that point four other major companies had already filed for Chapter 11 protection: Arch Coal, ANR, Patriot Coal, and Walter Energy. One analyst called it "the day coal died in the United States."

What's striking is how fast the coal industry went from boom to bust. In 2010, forecasts about the future of global coal demand closely resembled today's optimistic forecasts about growing global demand for natural gas. Those optimistic expectations were reinforced by a strong upward trend in coal prices, with benchmark coal prices increasing from $100 per tonne in January 2010 to $140 per tonne in January 2011. In early 2011, coal mining company stocks hit an all-time high, as promoters predicted a "super cycle" of growth based on China's domestic consumption. In its *World Energy Outlook 2010*, the IEA projected that the coal mining industry would see continued growth, including a 38% increase in Chinese production from 2008 to 2015, supporting coal-supply infrastructure investment of $720 billion in the period 2010–2035.

Figure 11. Peabody Energy stock chart, 2011–2016

Based on the confluence of indicators pointing safely toward an ongoing boom, coal mining companies took on increased debt as they undertook aggressive ramp-ups in new acquisitions of mines and investments in new mines.

In retrospect, the warning signs were clear, and the parallels with today's gas boom particularly striking:

- Mining companies were convinced that coal, long touted as the cheapest fuel, would maintain that advantage into the future. Similarly, today's boom in North American LNG terminals is based on a belief that the fracking boom has given North American producers a long-term advantage in global markets. But just as the fracking revolution enabled natural gas to push coal out of North American power markets, today plunging solar and wind cost structures threaten to similarly drive the displacement of natural gas.
- Mining companies, along with their political allies in Washington, D.C., and other capitals, failed to factor growing global concern over carbon pollution and other environmental impacts into their growth calculations. Yet as of early 2019, over 24 governments had committed to phasing out coal and over 100 banks and other financial lenders had instituted restrictions on coal financing.

APPENDIX B. METHODOLOGY

The Global Fossil Infrastructure Tracker uses a two-level system for organizing information. Summary data is maintained in Google sheets, with each spreadsheet row linked to a page on the SourceWatch wiki. Each wiki page functions as a footnoted fact sheet, containing project parameters, background, and mapping coordinates. Each worksheet row tracks an individual LNG plant unit. Under standard wiki convention, each piece of information is linked to a published reference, such as a news article, company report, or regulatory permit. In order to ensure data integrity in the open-access wiki environment, Global Energy Monitor researchers review all edits of project wiki pages by unknown editors. For each project, one of the following status categories is assigned and reviewed on a rolling basis:

- **Proposed:** Projects that have appeared in corporate or government plans in either pre-permit or permitted stages.
- **Construction:** Site preparation and other development and construction activities are underway.
- **Shelved:** In the absence of an announcement that the sponsor is putting its plans on hold, a project is considered "shelved" if there are reports of activity over a period of two years.
- **Cancelled:** In some cases a sponsor announces that it has cancelled a project. More often a project fails to advance and then quietly disappears from company documents. A project that was previously in an active category is moved to "Cancelled" if it disappears from company documents, even if no announcement is made. In the absence of a cancellation announcement, a project is considered "cancelled" if there are no reports of activity over a period of four years.
- **Operating:** The plant has been formally commissioned or has entered commercial operation.
- **Mothballed:** Previously operating projects that are not operating but maintained for potential restart.
- **Retired:** Permanently closed projects.

To allow easy public access to the results, Global Energy Monitor worked with GreenInfo Network to develop a map-based and table-based interface using the Leaflet Open-Source JavaScript library. The public view of the Global Fossil Infrastructure Tracker can be accessed at http://ggon.org/fossil-tracker/.

APPENDIX C. LIFE CYCLE GREENHOUSE GAS COMPARISON OF GLOBAL COAL PLANT DEVELOPMENT AND GLOBAL LNG TERMINAL DEVELOPMENT

To compare the impacts of the two fossil fuel categories—increased production and consumption associated with LNG terminals and increased coal production and consumption associated with new coal-fired power plants—we consider the full life cycle impacts from wellhead or coal mine through combustion. The results are shown in Table 7.

For coal, greenhouse gas impacts are mainly in the form of the carbon dioxide produced by coal-fired power plants. Additional global warming impacts result from the venting and leaking of methane from coal mines, and from releases of carbon dioxide by trains and ships.

The comparison between coal and gas requires converting any impacts from fugitive methane emissions into the atmosphere into a CO_2 equivalent. For natural gas, fugitive emissions occur throughout the production cycle, including well site, processing, transmission, storage, liquefaction, and distribution. Some methane “boils off” during ocean transit but is recaptured and burned by ship engines; methane is also combusted to fuel the liquefaction process and by end-use applications such as industrial heating or power generation.

Coal mining produces significant amounts of methane due to outgassing of coal seams. Such emissions are dramatically higher in underground mines. This analysis assumes that approximately equal shares of coal are produced globally by underground and surface mining. The analysis does not include combustion emissions resulting from the powering of natural gas wellhead or coal mining operations.

Table 7. Comparison between the greenhouse gas emissions enabled by pre-construction and in-construction coal plants (573 gigawatts) and the pre-construction and in-construction LNG export terminals (772 million tonnes per annum), based on 2018 utilization rates. Emissions in million tonnes CO_2 equivalent per annum.

Source of Emissions	Natural gas (20-year Horizon)	Coal (20-year Horizon)
Supply Chain Fugitive Methane	1,339	335
LNG Liquefaction	237	
LNG Transport	130	
LNG Regasification	8	
Coal Transport (ship)		11
Coal Transport (rail)		40
Combustion	1,733	2,361
Total	**3,446**	**2,747**

Source of Emissions	Natural gas (100-year Horizon)	Coal (100-year Horizon)
Supply Chain Fugitive Methane	529	133
LNG Liquefaction	221	
LNG Transport	130	
LNG Regasification	8	
Coal Transport (ship)		10
Coal Transport (rail)		40
Combustion	1,733	2,361
Total	**2,621**	**2,544**

Coal emissions are based on coal plants in pre-construction or construction as estimated by the Global Coal Plant Tracker, January 2019, in "Coal Plants by Country: Annual CO_2 (Million Tonnes) at http://bit.ly/31yblfC. For natural gas, emissions are based on LNG export terminals in pre-construction or construction as reported in Table 6 of this report, assuming the 2018 average global utilization rate of 79.04%. Supply chain methane leakage is assumed to be 2.3% (Alvarez 2018). Liquefaction, transport, regasification emissions are based on estimates by Pace Global (Pace 2015). In addition to the carbon dioxide emissions from coal, the estimate includes methane leakage from coal mines based on the assumption that half of thermal coal comes from surface mines, with an average of 8 cubic feet of methane released per short ton of coal, and half comes from underground mines, with an average of 360 cubic feet per short ton of coal (US DOE 2014). Coal shipping emissions are based on 2015 global CO_2 emissions for bulk shipping estimated by the International Council on Clean Transportation (Olmer 2017) of which 18.75% is thermal coal (Open Seas 2019). Coal rail emissions are based on 51.5 million tonnes per year CO_2 from total rail transport in the U.S. (Association of American Railroads 2008), of which 13% was coal (AARC 2016), scaled globally based on U.S. share of global thermal coal production (WEO 2018).

For additional methodology notes, see: Comparison of GHG Emissions for Proposed Terminals and Coal Plants, SourceWatch. http://bit.ly/2KKz5Y8

APPENDIX D: CAPITAL EXPENDITURES BY COUNTRY

The table below (Table 8) provides estimates by country for LNG projects (both export and import) in pre-construction and construction stages. Costs are based on International Gas Union estimates of $1,501 per tonne of annual capacity for greenfield export (i.e. liquefaction) projects, $458 per tonne for brownfield export projects, and $274 per tonne for greenfield and brownfield import (i.e. regasification) projects (IGU 2018).

Table 8. Capital Investments for LNG Terminals Under Development by Top 20 Countries (Billion US$)

Country	Pre-Construction	Construction	Total
USA	469.4	37.4	506.8
Canada	410.1	0.0	410.1
Russia	82.6	3.0	85.6
Australia	37.5	0.0	37.5
Tanzania	24.8	0.0	24.8
China	21.5	2.4	23.9
Indonesia	17.1	6.5	23.5
Mozambique	18.0	5.1	23.1
Iran	21.0	0.0	21.0
Papua New Guinea	17.3	0.0	17.3
Nigeria	15.0	0.0	15.0
India	8.1	2.7	10.8
Mexico	10.5	0.0	10.5
Cyprus	7.9	0.0	7.9
Equatorial Guinea	6.3	0.0	6.3
Algeria	6.0	0.0	6.0
Senegal	3.8	0.0	3.8
United Kingdom	3.3	0.0	3.3
Japan	3.2	0.0	3.2
Kuwait	0.0	3.1	3.1
Other	48.6	9.6	58.1
Total	**1,231.9**	**69.8**	**1,301.6**

Sources: Capacity estimates from Global Fossil Infrastructure Tracker, April 2019; Capital costs from IGU 2018.

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May 15, 2019

INTRODUCTION

"Engineers for a Sustainable Future" ("ESF") is an organization of engineers located in Oregon. We recommend that the application to construct the *230-mile Pacific Connector Natural Gas Pipeline from Malin to Coos Bay and the Jordan Cove Liquid Natural Gas (LNG)* be rejected. (Hereafter we will refer the the project as the Jordan Cove Project.)

Jordan Cove will have negative impacts on Oregon's environment as well as Oregon's efforts to reduce greenhouse gas pollution. There are other major projects worth considering for Coos Bay – one being the development of a project to build and support floating offshore wind (FOW) generation.

OFFSHORE WIND CAPACITY

Total installed electricity generation capacity in the United States is 1000+ GW. The National Renewable Energy laboratory (NREL) estimates that the offshore wind resource on the west coast is 800+ GW and that the area of highest resource is 200 miles south to 100 miles North or the California – Oregon border. In a 2017 article written by Robert Collier from the UC Berkley Labor Center entitled "*High Road for Deep Water: Policy Options for a California Offshore Wind Industry*", it is stated that substantial amounts of wind generation could be developed with installation of (FOW) turbines.

PORT OF COOS BAY

Offshore wind farms must be developed in conjunction with a suitable port to build and support the project. The Port of Coos Bay is well situated to serve as the supply chain hub for the FOW farm. It has sufficient land and a deep draft coastal harbor for import, assembly, manufacturing, operation and maintenance.

COMPARISON TABLE

The Table which follows - "Trade Study, Off-shore Wind vs LNG Export - compares the economic and environmental features of the Jordan Cove Project with a FOW project with base operations at Coos Bay. The table presents a high-level description of the two projects and compares commercial and environmental aspects.

COMPARISON TABLE (CONTINUED)

Information for the Jordan Cove project is based primarily on the project owner's March 2019 "Draft Environmental Impact Statement for the Jordan Cove Energy Project" (DEIS) and a January 2018 Oil Change International report entitled "Jordan Cove LNG and Pacific Connector Pipeline Greenhouse Gas Emissions Briefing".

The information presented for the FOW project is not complete. Construction Cost and State and Property Tax Revenue for the FOW project are not presented. Jobs that can be expected from the FOW wind project are only stated in terms of jobs associates with other FOW projects. (Item 9 in the attached table.) The *"High Road for Deep Water: Policy Options for a California Offshore Wind Industry"* and the *"Vineyard Wind Signs Lease for Staging Operations in New Bedford*" articles give an indication of the economic benefit of locating a FOW wind farm project construction, operation and maintenance at Coos Bay.

Michael Unger
Engineers for a Sustainable Future
www.esf-oregon.org

Trade Study, Coos Bay Floating Offshore Wind vs LNG Export
Engineers for a sustainable Future
May 15, 2019

Item Number	Item	North Spit Floating Offshore Wind (FOW) Project (1)	Pacific Connector Pipeline and Jordan Cove LNG Export Terminal Project (1)
PROJECT DESCRIPTION			
1	Renewable Energy Technology	Floating offshore wind	None
2	Energy Produced	Electricity delivered to CA / OR	LNG carbon intensive fuel, exported
3	Project Development/Management	EDPR Offshore North America LLC ("EDPR Offshore"), Principle Power, Inc. (PPI), and Aker Solutions Inc. ("ASI"), collectively the "Project Partners" has given consideration to development of land-based operations in Coos Bay. There is significant interest on the part of developers to construct floating offshore wind farms in the offshore areas 200 miles south and 100 miles north of the Oregon California boarder. Recently the U.S. Bureau of Ocean Energy Management (BOEM) received expressions of interest from 14 developers in the call for information and nominations for obtaining commercial wind energy leases offshore California. **(2)**	Pembina Pipeline Corporation (Canada)
4	Project concept	Docks built, offshore turbines assembled in Coos Bay, components delivered by sea, assembled turbines delivered to off-shore sites from harbor.	Methane delivered by Oregon pipeline, compressed in Coos Bay, docks built, off-loaded to vessels and delivered to Pacific Rim
5	Timespan for project development	30 years, possibly more	5 years construction. 40 years operation (estimate)
6	Construction Cost		$7.3 Billion over a 53-month construction period with $2.99 Billion spent in Oregon. Page 4-593 in DEIS **(3)**
7	Investors of Record		Carbon lenders in decline
8	Land Affected	Dock space and space for storage and assembly on the North Jetty.	LNG terminal facilities - 1,355 Acres, Connector pipeline and associated above ground facilities - 4,946 Acres, Page 2-38 and 2-39 in DEIS **(3)**.

Trade Study, Coos Bay Floating Offshore Wind vs LNG Export
Engineers for a sustainable Future
May 15, 2019

Item Number	Item	North Spit Floating Offshore Wind (FOW) Project (1)	Pacific Connector Pipeline and Jordan Cove LNG Export Terminal Project (1)
ECONOMIC CONSIDERATIONS			
9	Jobs in Oregon	**16 GW FOW Project** - "13,620 full-time Jobs for construction, installation and manufacturing by 2040 - 2050" and "4,330 full-time, long term jobs in operation and maintenance, plus thousands more service-sector jobs in the broader economy". Service sector jobs not included. **(4)** The 16 GW FOW project is a National Renewable Energy Laboratory (NREL) high-case estimate. Job estimates must be adjusted for different project sizes and development times. Also, Coos Bay jobs will depend on amount of manufacturing activities actually completed in Coos Bay. **0.8 GW FOW Project** - Vineyard Wine has committd to develop a 0.8 GW FOW farm. The company estimates that 3,600 jobs will be required to build and support the project. **(4)** Note: California's summer peak load is 76.414 GW and Oregon's peak summer load is 16.515 GW. **(5)**	Construction direct impact work force average over a 53-month construction period - 1023 Jobs. First year of operations - 180 Jobs in Coos Bay and 20 Jobs in Portland, Page 4-594 in DEIS **(3)**. Service sector jobs not included.
10	Investment opportunities / risks	California - Renewable portfolio standard 100% by 2045. Renewable energy procurements rising rapidly	Vessels half the size of competitors, no contracts for product, volatile market pricing, sunset industry, will face increasing worldwide carbon caps/price.
11	State and Property Tax Revenue		Annual State Tax - $50 Million, Annual Property Tax - $60 Million. Pembina Jordan Cove web page.
12	Social Cost of Carbon Globally (Based on $40 per metric ton)	Net reduction due to renewable energy build-out.	$1,470 - $2,080 Million per year. Emission estimates based on Oil Change International Briefing **(6)**
13	Social Cost of Carbon in Oregon (Based on $40 per metric ton)	Net reduction due to renewable energy build-out.	$88 Million per year. Emission estimates based on Oil Change International Briefing **(6)**
ENVIRONMENTAL CONSIDERATIONS			
14	Global Emissions - Carbon Dioxide Equialent (CO_2e)	Net reduction due to renewable energy build-out.	Increase in CO_2e emissions 36.8 - 52.0 million metric tons per year. Emission estimate based on Oil Change International Briefing **(6)**

Trade Study, Coos Bay Floating Offshore Wind vs LNG Export
Engineers for a sustainable Future
May 15, 2019

Item Number	Item	North Spit Floating Offshore Wind (FOW) Project (1)	Pacific Connector Pipeline and Jordan Cove LNG Export Terminal Project (1)
ENVIRONMENTAL CONSIDERATIONS (CONTINUED)			
15	Oregon Emissions - Carbon Dioxide Equialent (CO2e)	Net reduction due to renewable energy build-out.	Increase in CO2e emissions - 2.2 million metric tons per year. Emission estimate based on Oil Change International Briefing **(6)**
16	Investment in fossil fuel infrastructure	Possible minor investment in fossil fuel equipment such as tugboats.	$7.3 Billion **(3)**.
17	Other Environmental Impacts	Limited to industrial site on North Spit.	Dredging of oyster beds, clearing of forests for pipe-laying, fowling at water-crossings, water temperature in salmon streams rise by 0.5 Deg C.

(1) The FOW and Jordan Cove LNG projects could both be constructed in Coos Bay although the large ships required to transport the LNG to Asia would hinder operation of FOW transport operations in Coos Bay.

(2) US Bureau of Offshore Energy Management (BOEM) Request for Information. https://www.offshorewind.biz/:https://www.offshorewind.biz/2019/04/26/14-answer-california-offshore-wind-call/

(3) "*Draft Environmental Impact Statement for the Jordan Cove Energy Projec* t", Docket Nos. CP17-494-000 and CP17-495-000 March, 2019, https://www.federalregister.gov/documents/2019/04/12/2019-07313/notice-of-availability-of-the-draft-environmental-impact-statement-for-the-proposed-jordan-cove

(4) "*High Road for Deep Water: Policy Options for a California Offshore Wind Industry*". UC Berkley Labor Center, Robert Collier, November 2, 2017 Presents 2016 Analysis by National Renewable Energy laboratory (NREL Speer et all), http://laborcenter.berkeley.edu/high-road-for-deep-water/
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OFFSHORE WIND – AN ECONOMIC DEVELOPMENT OPPORTUNITY FOR COOS BAY

SUMMARY

A combination of recent developments has created a massive new economic opportunity for the port of Coos Bay. Utility scale solar and wind generation are now less expensive than new coal or gas plants. Last September California, the world's fifth largest economy, passed legislation (SB 100) requiring that 100% of its electric power be carbon-free by 2045. However, land-use restrictions, real estate costs, increasing scarcity of prime sites and other factors will limit the build-out of California's onshore wind and solar capacity.

These factors create a huge opportunity for offshore wind generation of electricity on the west coast. Typically stronger and more consistent than winds on land, offshore winds can help fill some gaps created at night by solar. The U.S. offshore potential is estimated to be four times the current generating capacity of the entire country. The area with the highest energy potential on the entire west coast is an offshore zone extending from Coos Bay 300 miles south into Northern California.

Coos Bay is the largest deep draft coastal harbor from San Francisco to the Puget Sound. It is well suited to establish itself as the nucleus for the development of this unique and vital natural resource. Much of the economic benefit that results from floating offshore wind farms comes from activities that are all done in port – staging turbines and components, assembly, local fabrication of parts, maintenance, operations base, etc. Completed turbines are towed offshore and anchored. If needed they are towed back to port for major maintenance and upgrades.

If the supply chain, assembly and service operations take root in Coos Bay, it will transform the economic vitality of the region and provide thousands of sustainable family-wage jobs according to a recent NREL/UC Berkeley report. Offshore wind is a new industry compared to land-based wind, but already employs 50,000 in Germany and the UK alone. Developers are currently planning wind farms in California waters near the Oregon border. This provides a short window of opportunity to leverage the superior port facilities at Coos Bay and secure the construction, operations and maintenance business of these projects.

Once a port is selected and the process begins, there is little incentive to duplicate it anywhere nearby due to the ease of transporting (towing) floating turbines. Oregon has a mature ($15 billion) marine construction industry and 2 major international players in offshore wind energy. This can help establish Coos Bay as the hub on the Pacific coast for this promising new industry .

Michael Mitton – 350PDX, Climate Reality Project

COOS BAY OFFSHORE WIND – OUTLINE FOR DISCUSSION & RESEARCH REFERENCES

1. SB100 (California 100% carbon-free by 2045) creates massive demand for clean energy

   a) SB 100 was signed into law Sept. 10, 2018 and ramps up RPS to 100% by 2045[1]
   b) This landmark climate action sends a clear signal to the market about the future of energy[2]
   c) Ranked as a separate country, California's economy would be the world's 5th largest
   d) California consumes 8% of US electricity but has 12% of the population
   e) California's aggressive goal to electrify transportation will further increase demand[3]
   f) Corporate renewable energy procurements rising rapidly further increasing demand[4]
   g) Since 2001 California carbon emissions have dropped 12% while its GDP increased 91%[5]

2. Utility scale costs for solar/wind generation are now lower than coal/gas and still declining

   a) Fuel is the major cost for coal/gas plants, but is free for wind/solar and always will be[6]
   b) Unpredictability of future gas/coal costs increases investment risk for these plants[7]
   c) Plants using fossil fuels also face significant and growing risk of GHG emission caps
   d) Storage is a key factor for wind/solar but cost are declining, new technologies emerging[8]
   e) All-in cost of wind energy (LCOE) now lower than fully depreciated natural gas plants[9]
   f) Wind now lowest cost technology type in many U.S. counties including externalities[10]
   g) LCOE onshore wind unsubsidized cost as low as $29 per MWh per Lazard 2018[11]
   h) Including subsidies onshore wind LCOE estimated as low as $14/MWh per Lazard[12]
   i) Offshore developed later than onshore wind so costs are higher but dropping fast[13]
   j) Worldwide offshore LCOE have fallen 56% and onshore LCOE 49% since 2010[14]
   k) APAC Offshore LCOE expected to fall 44% by 2023 per Wood Mackenzie[15]
   l) APAC expects 20X boom in offshore wind bringing it close to Europe's installed capacity[16]
   m) Overlapping competencies from oil/gas are benefiting offshore wind development[17]
   n) Stronger/steadier offshore wind increases capacity factor, lowers costs (Hywind 65%)[18]
   o) Wind will be EU's largest power source by 2027 more than gas, coal, nuclear per IEA[19]
   p) Europe now has several decades of experience; this will accelerate cost reductions in U.S.
   q) European technology, public policy, financing will inform, help expedite US development
   r) 2018 prices for offshore wind power in Europe now half of contract price paid in 2015[20]
   s) Aug 2018 offshore wind contract price in U.S. was $79 per MWh (PDX-based Avangrid)[21]
   t) Most recent previous U.S contract price was $132 per MWh, more than twice as much[22]
   u) Bigger turbines, economies of scale, install/operations improvements further reducing costs[23]
   v) Study projects 50% annual compound growth rate for U.S. offshore wind through 2026[24]
   w) Floating offshore wind (FOW) fleets have minimal environmental impact to sea-bed
   x) FOW has lower installation costs and risks due to onshore assembly, less specialized vessels[25]
   y) FOW vessels have less demanding port/harbor requirements than fixed foundation offshore
   z) FOW significantly lowers maintenance cost, structures towed back to port for major repairs[26]

3. Land-use issues, other factors favor offshore wind to provide big portion of renewable power

   a) Solar and wind generation requires several times more land compared to fossil fuel plants[27]
   b) PV solar needs at least 2.8 acres for 1GWh/yr meaning 32 acres required per 1000 homes[28]
   c) Onshore solar/wind face public resistance, land-use restrictions, high real-estate costs[29]

d) Growing population increases opportunity costs for land-based solar/wind
e) FOW's seasonal/geographical availability mitigates intermittency from other renewables
f) FOW complements California's vast solar capacity smoothing out the duck curve
g) Offshore wind typically has 2X the capacity factor vs. solar, key competitive advantage
h) Offshore wind has lower carbon footprint than fossil fuel, biomass, hydro and solar[30]
i) FOW spacing can accommodate/protect other ocean resources like fishing
j) 14 companies eyeing California offshore wind as of April 2019, up from 2 in 2018[31]

4. <u>Most valuable section of the offshore wind resource is centered on the California/Oregon border</u>

a) Total installed electricity generation capacity in United States is 1000+ GW
b) NREL estimates offshore wind resource on the west coast alone is 800+ GW
c) Area of highest energy density runs 300 miles south from Coos Bay into California
d) Wind resource in this area averages 10 meters/sec will yield high capacity performance
e) This area is relatively close to shore but deep, requiring floating offshore turbines
f) This area interferes less with shipping and military than other areas to north and south
g) Significant new transmission infrastructure needed to get this renewable power to market
h) Permitting, siting, litigations for transmission build-out could take up to 10 years

5. <u>Port of Coos Bay is well suited to act as the supply chain hub for this promising new industry</u>

a) Uptake of offshore wind depends on suitable port and grid infrastructure
b) Coos Bay is the largest deep draft coastal harbor from San Francisco to Puget Sound
c) New generation offshore turbines arrive by sea (too large for roads/rail)
d) Import, assembly, manufacturing requires enough quayside area, proximity to fleet site
e) Coos Bay served by deepwater with no overhead restriction, enough land available
f) Operations & maintenance (O&M) vessels need proximity to fleet site to optimize costs
g) Coos Bay was first choice of FOW developer (Principle Power) for pilot project in 2015
h) PPI met with stakeholders, local/state/federal agencies, elected officials[32]
i) Unable to secure an adequate PPA, project move 150 miles south to Eureka, CA[33]

6. <u>Clean energy is the industry of the future and provides long-term sustainable family wage jobs</u>

a) NE states 8GW offshore goal projects 36,300 full time jobs by 2030[34]
b) By 2014 Europe's 7.5GW offshore produced 75000 jobs in mfg, maintenance, ops[35]
c) UK offshore green collar jobs set to triple by 2030[36]
d) 4GW U.S. NE offshore lease sales (Dec. 2018 $405 million) highest ever[37]
e) 800MW offshore project creates 3600 jobs for port in Mass. to build/support wind farm[38]
f) Offshore supply chain development will drive most of the economic benefit for Coos Bay
g) Clean energy workers earn higher,more equitable wages compared to all workers nationally[39]
h) Establishing Coos Bay as supply chain and service hub for FOW will create many jobs
i) Full 16 GW offshore build-out in California generates 15,000 full time jobs per NREL[40]
j) 16GW build-out (high case) 4,330 full-time sustainable O&M jobs per UC Berkeley study[41]
k) 16GW build-out 13,620 full-time construction from 2020 to 2050[42]
l) 16GW build-out also adds thousands of service-sector jobs in the broader economy[43]
m) Wind turbine technician job growth rate and pay are twice the next best job (medical)[44]
n) If turbine, component firms manufacture locally, the economic impact is far greater
o) Coos Bay can benefit from jobs/economic activity even if wind farms are in California

7. There is a short window of opportunity to ensure the supply chain takes root in Oregon

a) SB100's time goals are aggressive: 60% carbon-free by 2030, 100% by 2045
b) FOW is a new and complex industry so build-out will take decades
c) These factors force FOW developers to make initial decisions ASAP
d) Port selection is a key early decision and drives where supply chain takes root
e) Leverage Oregon's $15 billion maritime industries to accelerate supply chain development[45]
f) Identifying workforce skills gap and developing strategies to fill it is critical for FOW
g) Clean Energy Jobs bill can provide funding for training in skills needed by FOW
h) Identify/reduce barriers to establishing Coos Bay as the supply chain and service hub

8. Success depends on Oregon's policy makers sending clear signals to wind developers, suppliers

a) Offshore wind is a new segment of clean energy and is capital intensive
b) Proving stable, long-term policy support will enable developers to attract investors
c) SB100 will drive exponential growth for FOW, need to ensure Coos Bay is ready
d) Policy needs to protect ocean resources and maintain adequate access for existing users
e) Policy framework in California has resulted in several offshore projects already[46]
f) Fishing industry and offshore wind co-exist and thrive at world's largest offshore wind farm[47]

9. Additional Topics

a) Explore synergies Highview LAES/Jordan Cove LNG liquefaction to increase efficiency[48]
b) Use surplus wind energy to convert sea water to hydrogen (H2) when demand is low[49]
c) Use H2 to produce power when demand is high, making FOW even more grid friendly[50]
d) H2 also valuable to de-carbonize difficult segments of transportation, heating, etc.[51]
e) Explore synergies with OSU's PacWave offshore hydrokinetic project near Newport[52]

Michael Mitton – 5/5/2019

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Document Content(s)

Coos Bay, FOW vs. LNG.PDF...1-5

Coos FOW Summary 050519 (002).PDF....................................6-6

Coos Bay Reference Material.PDF......................................7-11