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August 21, 2024

VIA E-MAIL

File Number. 94NM-384134

Ms. Amy Sweeney
Director, Office of Regulation, Analysis, and Engagement
U.S. Department of Energy
Office of Fossil Energy and Carbon Management
FE-34 - ROOM 3E-056
1000 Independence Avenue, S.W.
Washington, D.C. 20585
E-Mail: fergas.gov

Re: Gato Negro Permitium Dos, S.A.P.I. de C.V., Docket No. 24-__ LNG

Dear Mrs. Sweeney:

Enclosed for filing on behalf of Gato Negro Permitium Dos, S.A.P.I. de C.V. ("Gato Dos"), please find attached Gato Dos' Application for Expeditious Long-Term Authorization to (1) Export Natural Gas to, and Consume As Fuel In, Mexico From the United States, and (2) Upon Liquefaction, Re-Export LNG to From Mexico to Non-Free Trade Agreement Countries. As noted therein, Gato Dos respectfully requests that DOE/FECM issue the requested authorization on or before February 21, 2025. This filing includes the following:

1. Transmittal Letter
2. Application
3. Appendix A – Verification
4. Appendix B – Opinion of Counsel
5. Appendix C – Location of Pipeline Facilities
6. Appendix D – (Confidential) Location of Facility -Filed Under Seal
7. Appendix E - Enhanced Efficiency
8. Appendix F - Consumption Effects
9. Appendix G - Relative Emissions

10. Appendix H - Relevant Pipelines in Mexico
11. Appendix I - Additional Circumstances Associated with Gato Negro Permitium Dos Project
12. Appendix J E.I.A U.S. Natural Gas Supply Disposition and Prices Table 13
13. Appendix K Excerpts from the latest Lazard report
14. Appendix L NREL 2023 Study, excerpt
15. Appendix M Memorandum (LBNL-44698 (12/9/99) memo to Skip Laitier, EPA Office of Atmospheric Programs, from Jonathan Koomey, et al.)
16. Appendix N Solar Learning Center document
17. Appendix O NYSERDA web page
18. Appendix P October 27, 2021 letter from D. Whitehead, Director of Environmental Permits, NY State Dept. of Environmental Conservation to Ms. Brenda Colella
19. Appendix Q CLIMATEWIRE: "Michigan sets 2040 deadline to get all power from clean energy" [Climate Wire 11/29/23]; "Mich. City offers new model for 100% clean power" [EEnews 11/15/21]
20. Appendix R "Colorado is on track to nearly zero out power emissions – report" [Energy Wire 11/2/23]
21. Appendix S Citizen's Utility Board Analysis of CEJA
22. Appendix T Spectrum News 10/13/21 (HB 951); "North Carolina has a new clean energy law. Here's what's in it"
23. Appendix U Megawatt Daily, 11/21/23, p. 4

Gato Dos hereby requests privileged and confidential treatment of the Confidential Exhibit contained in Appendix D and an exemption from disclosure under the Freedom of Information Act, 5 U.S.C. § 552, as amended. *See also* 10 C.F.R. §§ 590.202(e) and 1004.11. That material, which constitutes Appendix D, will be sent under separate correspondence to the Department via overnight courier, and marked as non-public information.

Pursuant to 10 C.F.R. § 590.207, Gato Dos has transmitted the $50.00 filing fee via pay.gov. Please return a date-stamped copy of the filing at your earliest convenience.

Please contact me if you have any questions.

Sincerely,

/s/ Mark F. Sundback
Mark F. Sundback
Attorney for Gato Negro Permitium Dos, S.A.P.I de C.V.

SMRH:4878-6485-7306.1

cc: Jennifer Wade
Peri Ulrey

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
OFFICE OF FOSSIL AND CARBON MANAGEMENT

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Gato Negro Permitium Dos, S.A.P. I. de C.V.	)	Docket No. 24-___ LNG
	)	

APPLICATION OF GATO NEGRO PERMITIUM DOS, S.A.P. I. de C.V. FOR EXPEDITIOUS LONG-TERM AUTHORIZATION TO EXPORT NATURAL GAS TO, AND CONSUME AS FUEL IN, MEXICO FROM THE UNITED STATES AND UPON LIQUEFACTION, RE-EXPORT LNG FROM MEXICO TO NON-FTA COUNTRIES

August 21, 2024

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UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
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Pursuant to Section 3 of the Natural Gas Act ("NGA")[1] and Part 590 of the Department of Energy ("DOE") Regulations,[2] Gato Negro Permitium Dos, S.A.P. I. de C.V. ("Applicant" or "Gato Dos")[3] hereby applies ("Application") to DOE's Office of Fossil Energy and Carbon Management ("DOE/FECM")[4] for expeditious long-term authorization to export via pipeline initially to Mexico up to 0.647 billion cubic feet ("Bcf") per day of natural gas, and ultimately re-export for delivery to any country that has not signed a Free Trade Agreement with the United States ("FTA") (such countries are "non-FTA Countries") up to 0.556 Bcf/d of liquified natural gas ("LNG"). Applicant requests this authorization become effective on the date of first exportation under this authorization and terminate on December 31, 2050. Applicant requests an order from DOE/FECM that would authorize exports on Applicant's own behalf and as agent for affiliates of Applicant who may hold title to the natural gas at the time of export.

Applicant requests authorization to export natural gas via pipeline to Mexico, an FTA

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1 15 U.S.C. § 717b.

2 10 C.F.R. Part 590.

3 Big River Energy, LLC, an affiliate of Applicant, was granted authority under a Blanket Authorization to Export Natural Gas to Mexico in FECM Docket No. 22-151-NG on December 15, 2022. *See* DOE/FECM Order No. 4938.

4 Authority to regulate the imports and exports of natural gas, including liquefied natural gas, under section 3 of the NGA (15 U.S.C. § 717b) has been delegated to the Assistant Secretary for FECM in Redelegation Order No. S4-DEL-FE1-2021, issued on March 25, 2021. On July 4, 2021, the Office of Fossil Energy changed its name to the Office of Fossil Energy and Carbon Management.

nation requiring national treatment for trade in natural gas. Once in Mexico, the volumes may be liquefied in the Gato Negro Manzanillo LNG plant under development in the State of Colima, Mexico ("Manzanillo Plant"). Once liquefied, the methane could be exported to non-FTA Countries. If, however, authorization in this docket for exportation from the U.S. to Mexico of volumes then consumed within Mexico as fuel or lost and unaccounted for volumes, is deemed to be duplicative of authority obtained in DOE/FECM Docket No. 24-43-LNG for fuel, lost and accounted volumes, for FTA use, then Applicant need not receive separate FTA country authority herein for volumes consumed in Mexico.

Section 3(c) of the NGA has been interpreted to mean that DOE shall grant an LNG export application unless the agency "makes an affirmative showing of inconsistency with public interest." *Sierra Club v. DOE*, 867 F.3d 189, 203 (D.C. Cir. 2017).[5] Applicant requests that DOE/FECM issue an order no later than February 21, 2025, granting the authorization requested in the Application without modification, change, substitution or further delay, for natural gas exportation.

In support of this Application, Applicant respectfully states as follows:

I. DESCRIPTION OF APPLICANT

The exact legal name of the Applicant is Gato Negro Permitium Dos, S.A.P. I. de C.V. Applicant is a corporation organized under the laws of Mexico. Applicant is engaged in arranging natural gas export volumes from the U.S. to non-FTA Countries. Affiliates of Applicant are involved in developing a liquefication complex in Manzanillo, Mexico to provide

[5] 15 U.S.C. § 717b(c) ("The Commission shall issue [an] order upon application, unless, after opportunity for hearing, it finds that the proposed exportation . . . will not be consistent with the public interest." *See also* order of the U.S. Court of Appeals for the D. C. Circuit, Case Nos. 16-1186, 16-1252 and 16-1253. *Sierra Club v, Dep't of Energy* (D.C. Cir., 2017).

LNG to markets accessible through shipping in the Pacific Ocean. Applicant has its principal place of business at Montes Urales 754, Piso 4, Col. Lomas de Chapultepec C.P. 11000, Ciudad de México. Half of the outstanding shares in Gato is owned by Mr. Carlos Camacho, and half is owned by Mr. Emilio Fuentes (both of whom are citizens of Mexico), who also own, in the same proportions, the outstanding voting securities of affiliates Gato Negro Permitium Uno, S.A.P.I, de C.V. ("Gato Uno") and Gato Negro Manzanillo S.A.P.I., de C.V., the latter of which is directly involved in developing the Manzanillo Plant. Gato Uno has a separate and distinct corporate existence from Gato Dos.

II. COMMUNICATIONS

All communications and correspondence regarding this Application, including all service of pleadings and notice, should be addressed to the following persons:

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III. PROJECT DESCRIPTION

A. LNG Facility

Applicant requests long-term authorization to export up to 0.647 Bcf per day of natural gas to Mexico via pipeline. The liquification will occur at an approximately 24.7 acre site, controlled by Applicant's affiliates, in Manzanillo. A map of the location of the facility is included in Appendix D. This is the same site and liquefaction capacity to be used by Gato Uno. The specific map is filed under seal. The Project's exact location could be used by competitors in an effort to capture commercial advantage, or raise the cost to Applicant of accessing that property, and hence is entitled to protected treatment.

The major components that will be constructed as part of the Project include: (a) up to four (4) liquefaction trains capable of producing up to approximately 4 MMTA of LNG and a gas pre-treatment unit for removal of Mercury, acid gas, water, and natural gas liquids; (b) a marine jetty; (c) emergency vapor management equipment; (d) piping and other facilities to permit the interconnection of the Project to existing pipeline infrastructure and (e) associated utilities interconnections. Feed gas for the Project will be supplied through the TC Energy Guadalajara Manzanillo pipeline. New or modified utilities and offsite facilities will be provided for the Project as required.

The Project will use a modular structure employing a refrigerant technology process. Exported volumes may be liquefied to be re-exported from the Manzanillo Plant to other nations with whom the U.S has not entered into a Free Trade Agreement, or transported for consumption in Mexico (all of the foregoing, "non-FTA Countries"). The LNG will be loaded for ocean-going transport. In addition, the Manzanillo Plant will include a truck rack in case some proportion of the natural gas volumes would be resold and consumed in Mexico. As noted above, the foregoing equipment and capacity would be used by Gato Dos up to the maximum value stated in this application; alternatively, some or all of that facility capacity or commodity volume could be devoted to sales to FTA countries by Gato Uno.

The Manzanillo plant's location will benefit signatories to non-FTA Countries. LNG from Manzanillo will not need to transit the potential bottleneck of the Panama Canal that other LNG supplies from the U.S. Gulf Coast may experience when headed into the Pacific. The Manzanillo location also will reduce consumption of maritime fuel for ships transporting LNG to countries located on the Pacific Ocean relative to those cargoes that might serve the same markets that are transported from the U.S. Gulf Coast. *See* 85 Fed. Reg. 78197, 78198 (text at n.9) (2020).

B. Transport to Manzanillo

Applicant will source the natural gas that it intends to export to Mexico and thence to non- FTA Countries pursuant to the requested authorization.

Through upstream interconnections at highly liquid trading points in Texas, Applicant will be able to source gas from a variety of suppliers in the domestic market.

Applicant plans on exporting natural gas to non-FTA Countries through the duration of its term of the authorization requested herein, by negotiating and entering into one or more supply agreements of various durations with natural gas producers and marketers in production areas in Texas. Consistent with other export authorization applicants, Applicant may supply a substantial part of such exports through short-term agreements and spot market purchases. Maintaining this flexibility to acquire natural gas supplies from multiple producers on different terms will allow Applicant to access a diversity of natural gas supplies on favorable economic terms.

Applicant has not entered into any long-term natural gas supply contracts with producers or marketers as of the date of this Application. Applicant will file with DOE/FECM, under seal, all executed long-term supply agreements associated with the export of natural gas under the requested authorization within 30 days of execution of such agreements, in each case in accordance with DOE's regulations.

Applicant will enter into agreements to receive transportation service on one or more connecting pipelines, starting with capacity on one or more U.S. pipelines transporting volumes to border-crossings with Mexico ("Pipeline Capacity"). The options available are:

1. Roadrunner Pipeline, LLC (“Roadrunner”)[6] an intrastate pipeline accessing the San Elizario border crossing point, originating near Cayanosa, Texas. Roadrunner transports up to 640 MMcf/d through approximately 200 miles of 30-inch diameter pipeline. ONEOK is the operator of the pipeline;

2. The Comanche Trail Pipeline, LLC, with a capacity of 1.1 Bcf/d, an intrastate pipeline operated by Energy Transfer which follows approximately the same route as Roadrunner;[7] and

3. Trans-Peco Pipeline, LLC (“TPP”), which is an intrastate pipeline that also originates in the Waha area and delivers gas to the border-crossing point that is adjacent to the State of Chihuahua.[8]

The Pipeline Capacity will transport the volumes to two points on the U.S.-Mexico border:

A. The San Elizario Border Crossing to Mexico, located along the international border between the United States (about 40 miles from El Paso, Texas) and Mexico in the vicinity of Colombia, State of Nuevo León will be accessed by Roadrunner and Comanche Trail. There volumes will be tendered to the Tarahumara Gas Pipeline owned by Esentia Energy, formerly known as Fermaca de Mexico. Tarahumara is regulated by the Comisión Federal de Electricidad. Esentia is a leading gas infrastructure player in Mexico that develops, builds, owns, and operates pipelines and other related energy assets in the country. Its current-operating pipelines are capable of transporting 1.2 billion cubic feet per day.

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[6] ONEOK Partners, L.P. owns half of the 50-50 joint venture in Roadrunner with a subsidiary of Esentia Energy, formerly Fermaca Infrastructure B.V. (Fermaca), a Mexico City-based natural gas infrastructure company.

[7] Comanche Trail is subject to a Statement of Operating Conditions on file with FERC. *See* FERC Docket No. PR22-67-000 (Jan. 18, 2022) letter from J. White, Director of Regulatory Affairs to Ms. Kimberly Bose, Secretary, Federal Energy Regulatory Commission.

[8] TPP has a Statement of Operating Conditions on file with FERC. *See* FERC Docket No. PR22-68. *See* Appendix H hereto.

B. The Presidio/Ojinaga border-crossing in the State of Chihuahua will be accessed by TPP. Supplies available at Presidio/Ojinaga will be transported in the Gasoducto Ojinaga-El Encino system for 220 kilometers before connecting to the Wahalajara system. Gasoducto is operated by Sempra and owned by Comisión Federal de Electricidad.

All of the foregoing facilities and commodity volumes also may be used to make sales by Gato Uno to FTA countries; the capacity and volume requested is a maximum value that could be utilized by either Gato Dos or Gato Uno, or both and the use by one would reduce commensurately the other entity's ability to use the maximum capacities and volumes identified herein.

C. Mexican Regulatory Review of the Project and Pipelines in Mexico

The Project does not involve construction in the United States. Given the location of the Project in Mexico, the facility will not be subject to the review of the FERC under the NGA or NEPA. Instead, the Project and any pipeline facilities that may be constructed in Mexico are subject to review and approval by Mexican agencies under the state and federal laws of that nation.

Gato began the Mexican permitting process in June 2022. Over one hundred permits, licenses or authorizations in Mexico are required, including archaeological, construction, water, commercial and transportation and, as detailed below, environmental. The Mexican permitting process includes a thorough environmental review under Mexican state and federal legislation analogous to the review conducted by U.S. agencies under NEPA. Specifically, Mexico's primary statute governing the environmental reviews of projects is the Ley General del Equilibrio Ecológico y la Protección al Ambiente/General Law of Ecological Balance and Environmental Protection ("LGEEPA"), which is administered by the Secretaría de Medio Ambiente y Recursos Naturales/Ministry of Environmental and Natural Resources

("SEMARNAT"). Within the SEMARNAT, the Agencia Nacional de Seguridad Industrial y de Protección al Medio Ambiente del Sector Hidrocarburos/National Agency for Industrial Security and Environmental Protection for the Hydrocarbon Industry ("ASEA"), is responsible for regulating and supervising industrial, operational and environmental safety for projects related to the hydrocarbon sector, including the construction of natural gas pipelines and liquefaction facilities.

As part of ASEA's review of projects under the LGEEPA, a Manifestación de Impacto Ambiental/Environmental Impact Assessment ("MIA") must be prepared. Similar to an Environmental Impact Assessment Statement ("EIS") under NEPA, a MIA presents the results of comprehensive analysis and studies of potential environmental impacts associated with a project, including site preparation, construction, operation, and decommissioning, as well as an assessment of measures to mitigate environmental impacts and an analysis demonstrating compliance with Mexican laws and regulations, as well as prudent industry practices and international standards. The MIA must describe the stages of construction and the ecosystems in which it will be developed. The document presents the results of comprehensive analyses and environmental studies, including an assessment of mitigation measures. The MIA for gas pipelines and liquefaction facilities must also include an Environmental Risk Analysis, which analyzes safety and risk mitigation procedures.

If ASEA concludes that a project is environmentally viable, it will issue a resolution approving the MIA and an Environmental Impact Authorization ("ERA"), which specifies the authorization's terms and conditions, including required measures to mitigate environmental impacts. In doing so, ASEA reviews public consultation process inputs. Various federal and state agencies are notified during the evaluation process. The ASEA enforces the terms of a

MIA and the ERA falls under the jurisdiction of ASEA, which can periodically verify to ensure compliance with all applicable environmental regulations, as well as the terms and conditions of environmental permits. ASEA also oversees a facility's continued compliance with applicable laws, regulations, and conditions governing safety, risk mitigation, technical processes, and the environment through enforcement of the Sistemas de Administración de Seguridad Industrial, Seguridad Operativa y Protección/Industrial, Operational, and Environmental Safety Management System.

ASEA also reviews and issues authorizations for projects, such as pipelines and liquefaction facilities, that will impact existing land use. In reviewing such proposals, ASEA relies upon a technical opinion issued by the members of the Consejo Forestal Estatal/State Forestry Council in the form of an Estudio Técnico Justificativo/Technical Justification Study submitted by the applicant analyzing impacts regarding biodiversity and discussing effects on soil erosion, detriment to water quality, or diminished rate of recovery, among other environmental impacts. Any land use change must be authorized by ASEA in a permit referred to as a Cambio de Uso de Suelo en Terrenos Forestales/Forestry Land Use Change Permit which also specifies mitigation requirements similar to those included in the MIA

Project proponents in the hydrocarbon industry, including pipeline and liquefaction facilities, must perform a Social Impact Assessment ("Evaluación de Impacto Social") ("EvIS") identifying, characterizing, and assessing social impacts stemming from the project and propose a social management plan. The EvIS is subject to review and approval of the Secretaría de Energía/Ministry of Energy. Applicant expects to receive its EvIS permit by the end of the third quarter of 2024. In addition, permits are required from the Comisión Reguladora de Energía/Energy Regulatory Commission to engage in activities that are subject to third-party access and those activities that are not subject to third-party access but require a permit, including the self-supply of electric energy, transportation, liquefaction regasification, and storage of natural gas in Mexico. Applicant expects to receive CRE permits by the end of the third quarter of 2024.

IV. REQUESTED AUTHORIZATION

Applicant requests long-term authorization to export up to 0.647 Bcf per day of natural gas to Mexico via pipeline commencing on the date volumes are first exported under the authorizations,[9] on its own behalf and as agent for others[10] who hold title to the natural gas at the time of export. Applicant further requests authority to re-export from Mexico to any non-FTA Country such volumes, less pipeline system lost, unaccounted-for and fuel volumes and amounts consumed for liquefaction at the Manzanillo Plant.[11] This application seeks authority to re-export to non-FTA Countries aside from Mexico the equivalent of 0.556 Bcf/d, or 10,959 Mt/d of LNG.

Applicant will fully comply with all applicable DOE/FECM requirements for both exporters and their agents, including but not limited to registering with DOE/FECM each natural gas title holder that Applicant seeks to export natural gas as agent and providing DOE/FECM a written statement by the title holder that acknowledges and agrees to (1) comply with all requirements in Applicant's long-term export authorization and (2) include those requirements in any subsequent purchase or sale agreement entered into by the title holder.[12] Applicant will file

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9 A long-term authorization need not be limited by the terms of the associated long-term commercial agreements. *See, e.g.*, *SB Power Solutions Inc.,* Docket No. 12-50-LNG, DOE/FECM Order No. 3105 (Jun. 15, 2012) (granting 25-year authorization without coextensive long-term arrangements).

10 Such affiliates would include any entity, directly or indirectly, through one or more intermediaries, controlling, controlled by, or under common control with the Applicant. It may also include unaffiliated entities.

11 Applicant anticipates that lost, unaccounted for and fuel volumes associated with transmission on pipelines in Mexico will not exceed 7.6%, and that fuel and loss for liquefaction will not exceed 6.6%, of the total export authorization, and may be materially lower.

12 Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC, DOE/FECM Order No. 2913 (Feb. 10, 2011)

any long term gas supply or long term export contracts with DOE/FE, under seal, and provide relevant information in accordance with DOE regulations,[13] once executed.

An affiliate of Applicant currently has a blanket authorization to export up to 13.58 Bcf of natural gas to Mexico via pipeline pursuant to DOE/FECM Order No. 4938 for a two-year term that began on December 15, 2022. That affiliate also applied for authority to export natural gas only to Mexico and only by truck, and only through 2030, which was granted May 31, 2024.[14] That authorization in no way overlaps with the instant Application. Applicant also has an affiliate seeking long term authority for exports to FTA countries.[15] For the sake of clarity, the authorization sought herein would involve facility capacity and natural gas volumes that would potentially be used in Gato Uno's sales to FTA countries as well. For instance, if Gato Dos on a specific day used the entire .647 Bcf of pipeline export authorization requested herein, Gato Uno would not be able to use any of its FECM Docket No. 24-43-LNG authorization on that same day to transport natural gas on pipeline capacity. Applicant further states that, to the best of its knowledge, other than as noted above, the same or any related matter is not being considered by any other part of DOE, including the Federal Energy Regulatory Commission, or any other Federal agency or department.

V. PUBLIC INTEREST ANALYSIS

A. Applicable Legal Standards

Pursuant to sections 301(b) and 402 of the Department of Energy Organization Act,[16] and delegations of authority issued thereunder, the DOE/FE is responsible for evaluating applications

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(establishing the criteria for exports for agents subsequently adopted in a number of orders); Gulf Coast LNG Export LLC, DOE/FECM Order No. 3163 at 7-8 (Oct. 16, 2012) (reiterating agency policy).

13 *See e.g.*, 10 C.F.R. § 1004.1, *et seq.*

14 DOE/FECM Order No. 5120.

15 FECM Docket No. 24-43-LNG.

16 42 U.S.C. §§ 7151(b), 7172 (2012).

to export natural gas and LNG from the United States under section 3 of the NGA.[17] This Application requests authority to export natural gas produced in the United States to Mexico for consumption in that country as fuel for pipeline transportation and liquefaction processes, which should be deemed in the public interest and granted without modification or delay, as required by NGA section 3(c).[18] As clarified in Order No. 3768,[19] the applicable legal standard for the portion of the Application that requests authorization to re-export U.S. natural gas from Mexico to non-FTA countries is set forth in section 3(a) of the NGA.[20]

The general standard for review of applications to export to non-FTA countries is established by section 3(a) of the NGA, which provides that:

> The [Secretary] shall issue such order [authorizing exports from the U.S.] upon application, unless, after opportunity for hearing, it finds that the proposed exportation or importation will not be consistent with the public interest. The [Secretary] may by its order grant such application, in whole or in part, with such modification and upon such terms and conditions as the [Secretary] may find necessary or appropriate, and may from time to time, after opportunity for hearing, and for good cause shown, make such supplemental order . . . as it may find necessary or appropriate.[21]

In applying this provision, the DOE/FE has consistently found that section 3(a) creates a rebuttable presumption that proposed exports of natural gas are in the public interest.[22] The

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17 15 U.S.C. § 717b. This authority is delegated to the Assistant Secretary for Fossil Energy pursuant to Redelegation Order No. 00-002.04G (June 4, 2019).

18 Section 3(c) was added to the NGA by section 201 of the Energy Policy Act of 1992. Energy Policy Act of 1992, Pub. L. No. 102-486, § 201, 106 Stat. 2776, 2866 (1992). 15 U.S.C. § 717b(c). Volumes may be consumed as fuel in Mexico. That section provides in relevant part that applications to the DOE/FE associated with transportation requesting authority for the export of natural gas, including LNG, to a nation with which there is in effect a FTA requiring national treatment for trade in natural gas (*e*.g., Mexico) shall be deemed consistent with the public interest and granted without modification or delay. 15 U.S.C. § 717b(c).

19 DOE/FE Order No. 3768, FE Docket No. 14-179-LNG, "Opinion and Order Granting Long-Term Multi-Contract Authorization . . . ." ("Order No. 3768").

20 15 U.S.C. § 717b(a).

21 *Id.* § 717b(a).

22 *Sierra Club v. U.S. Dep't of Energy*, 867 F.3d 189, 203 (D.C. Cir. 2017). *See also, Lake Charles Exports, LLC*, DOE/FE Order No. 3324-A, FE Docket No. 11-59-LNG, Final Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas By Vessel From the Lake Charles Terminal in

DOE/FE will grant a non-FTA export application unless there is an affirmative showing based on evidence in the record that the export would be inconsistent with the public interest.[23]

The DOE/FE has looked to the 1984 Policy Guidelines setting out the criteria to be employed in evaluating applications for natural gas imports,[24] and has found these Policy Guidelines applicable to natural gas export applications, as well.[25] The Policy Guidelines specify:

> The market, not government, should determine the price and other contract terms of imported [or exported] gas . . . The federal government's primary responsibility in authorizing imports [or exports] should be to evaluate the need for the gas and whether the import [or export] arrangement will provide the gas on a competitively priced basis for the duration of the contract while minimizing regulatory impediments to a freely operating market.[26]

Calcasieu Parish, Louisiana, to Non-Free Trade Agreement Nations, at 13 (July 29, 2016); *Lake Charles LNG Export Company, LLC*, DOE/FE Order No. 3868, FE Docket No. 13-04-LNG, Opinion and Order Granting Long- Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Lake Charles Terminal in Calcasieu Parish, Louisiana to Non-Free Trade Agreement Nations, at 11 (Jul. 29, 2016); *Cameron LNG, LLC*, DOE/FE Order No. 3846, FE Docket No. 15-90-LNG, Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From Trains 4 and 5 of the Cameron LNG Terminal in Cameron and Calcasieu Parishes, Louisiana, to Non-Free Trade Agreement Nations, at 10 (July 15, 2016); *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 3792, FE Docket No. 15-63-LNG, Final Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Sabine Pass LNG Terminal Located in Cameron Parish, Louisiana, to Non-Free Trade Agreement Nations, at 13 (Mar. 11, 2016).

23 *Phillips Alaska Nat. Gas Corp. & Marathon Oil Co.*, DOE/FE Order No. 1473, FE Docket No. 96-99- LNG, Order Extending Authorization to Export Liquefied Natural Gas from Alaska, at 13 n.42 (Apr. 2, 1999) (citing *Panhandle Producers & Royalty Owners Ass'n v. ERA,* 822 F.2d 1105, 1111 (D.C. Cir. 1987)); *see also Lake Charles Exports, LLC*, DOE/FE Order No. 3324-A, at 13; *Lake Charles LNG Export Co.*, DOE/FE Order No. 3868 at 11; *Cameron LNG, LLC*, DOE/FE Order No. 3846 at 10; *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 3792 at 13-14.

24 New Policy Guidelines and Delegation Orders From Secretary of Energy to Economic Regulatory Administration and Federal Energy Regulatory Commission Relating to the Regulation of Imported Natural Gas, 49 Fed. Reg. 6,684 (Feb. 22, 1984) [hereinafter "Policy Guidelines"].

25 *Phillips Alaska Nat. Gas Corp.*, at 14, 42; *see also Lake Charles Exports, LLC*, DOE/FE Order No. 3324- A, at 14; *Lake Charles LNG Export Company, LLC*, DOE/FE Order No. 3868, at 12; *Cameron LNG, LLC* DOE/FE Order No. 3846, at 11; *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 3792, at 15.

26 Policy Guidelines at 6,685. The DOE/FE's analysis has also been guided by DOE Delegation Order No. 0204-111. U.S. Department of Energy, Delegation Order No. 0204-111 (Feb. 22, 1982) [hereinafter "Delegation Order"]. According to the Delegation Order, exports of natural gas were to be regulated primarily "based on a consideration of the domestic need for the gas to be exported and such other matters [found] in the circumstances of a particular case to be appropriate." Delegation Order at para. (b).

See generally, Sierra Club, et al., "Order Denying Petition For Rulemaking on Exports of Liquefied Natural Gas," U.S. Dep't of Energy, Office of Fossil Energy and Carbon Management (July 18, 2023).

The DOE/FE's review of export applications considers: (i) the domestic need for natural gas proposed to be exported; (ii) whether the proposed exports pose a threat to the security of domestic natural gas supplies; (iii) whether the arrangement is consistent with the DOE/FE's policy of promoting market competition; and (iv) any other factors bearing on the public interest.[27]

The DOE/FE also has identified as relevant in determining whether proposed exports are in the public interest:

- whether the exports will be beneficial for regional economies;
- the extent to which the exports will foster competition and mitigate trade imbalances with the foreign recipient nations; and
- the degree to which the exports would encourage efficient management of U.S. domestic natural resources.[28]

As demonstrated below, the exports of natural gas and LNG proposed herein further the public interest.

B. Domestic Need for the Gas to be Exported

The backdrop to the Project is rapid growth in U.S. natural gas resources and production. For instance, estimates of recoverable U.S. natural gas resources in just the Permian Basin increased by approximately 1,081 Tcf (62%) between 2009 and 2020.[29] Then EIA estimates

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27 *See, e.g., Lake Charles Exports, LLC*, DOE/FE Order No. 3324-A, at 15; *Cameron LNG, LLC*, DOE/FE Order No. 3846, at 11-12; *Cameron LNG, LLC*, DOE/FE Order No. 3391-A, FE Docket No. 11-162-LNG, Final Opinion and Order Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Cameron LNG Terminal in Cameron Parish, Louisiana, to Non-Free Trade Agreement Nations, at 9-10 (Sept. 10, 2014); *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2961, FE Docket No. 10-111-LNG, Opinion and Order Conditionally Granting Long-Term Authorization to Export Liquefied Natural Gas From Sabine Pass LNG Terminal to Non-Free Trade Agreement Nations, at 29 (May 20, 2011).

28 *See, e.g., Cameron LNG, LLC*, DOE/FE Order No. 3846, at 105-125; Sabine Pass Liquefaction, LLC, DOE/FE Order No. 3792, at 162-191, *Cameron LNG, LLC*, DOE/FE Order No. 3391-A, at 125-35; *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2961, at 34-38.

29 *Compare* Assumptions to the AEO 2020, Oil and Gas Supply Module, at tbl. 2 *with* U.S. Energy Information

increased *again* for Year-End 2021.

> "Proved reserves of natural gas in the United States grew to a new record of 625.4 trillion cubic feet (Tcf) in 2021, *a 32% increase* from 2020," according to EIA's recently released Proved Reserves of Crude Oil and Natural Gas in the United States, Year-End 2021 report. [Emphasis added]. [30]

Texas has by far the largest level of reserves among the states. *Id.*

In the publication entitled "Natural gas explained: *How much natural gas is left"* (emphasis added), EIA stated that

> "U.S. natural gas proved reserves have increased nearly every year since 2000. . . . . According to *U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2021*, as of December 30, 2021, U.S. total natural gas proved reserves . . . totaled about 625.4 trillion cubic feet (Tcf). This volume was a 32% increase from the estimated 473 Tcf of proved reserves at end of 2020. The dry natural gas portion of these reserves . . . is about 589 Tcf, a 32% increase from the 445 Tcf of dry gas reserves in 2020."

"The United States has enough dry natural gas to last about 86 years," to say nothing of associated gas production. [EIA - "FAQ: How much natural gas does the United States have, and how long will it last?"]

Growth in U.S. production is expected to continue over the next several decades. Total U.S. dry gas production is projected to increase to 42.07 Tcf by 2050, reflecting a 0.5% annual growth rate between 2024 and 2050.[31] In DOE's reference case, "U.S. natural gas production increases by 15% from 2022 to 2050, and consumption decreases by 6% . . . . *Across all cases*, domestic production outpaces domestic consumption." AEO 2023, p. 27 (emphasis added).

Administration, *Assumptions to the Annual Energy Outlook 2009*, tbl. 9.2 (Mar. 2009) [hereinafter Assumptions to the AEO 2009], http://www.eia.gov/forecasts/archive/aeo09/assumption/pdf/0554(2009).pdf.

30 "Proved reserves of natural gas increased by 32% in the United States during 2021 (Jan. 30, 2023) EIA. The largest production increase in the U.S. occurred in the Permian Basin, which in 2023 experienced production growth of 2.6%, or more than 2.5 Bcf/d. U.S. Natural Gas production grew by 4% in 2023, similar to 2022" (March 27, 2024) EIA.

31 AEO 2020 at tbl. 13, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-. O2020&cases=ref2020&sourcekey=0.

Across all of EIA's most recent LNG export scenarios, total natural gas *consumption* within the U.S. is relatively stagnant through 2050. Despite stagnant domestic demand for natural gas, supply will grow substantially. For example, though demand for natural gas has increased since 2009, production of natural gas experienced even more rapid growth.[32] According to data published by the EIA, U.S. natural gas consumption only increased 29% from 2010 to 2019.[33]

In the future EIA's reference case projects domestic natural gas consumption to *decrease* by more than 10% from 2022 to 2034, never to return to last year's level. *See* App. K hereto.[34] In its Annual Energy Outlook 2023, the EIA estimates long-term annual U.S. diminution of demand by -0.2%, with demand expected to end up at 30.01 Tcf in 2050.[35]

The EIA forecasts that natural gas consumption in the electric power sector will decrease to 7.74 Tcf in 2050 from about 12 Tcf in 2022 in the Reference case.[36] "[D]omestic natural gas consumption for electricity generation is likely to decrease by 2050, relative to 2022 . . . ." AEO 2023, p. 25.

The reasons why the EIA's long term outlook for natural gas demand in the U.S., particularly for electric generation, is dimming, are clearly linked to economic realities. Data from Lazard's annual Levelized Cost of Energy Report issued June 2024 reinforce this point. The pertinent portions of Lazard's survey show that *even before the effect of massive Inflation Reduction Act tax benefits is factored in*, the low end of the range of wind energy projects has the

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32 The Brattle Group, Understanding Natural Gas Markets, at 3 (Sep. 2014), https://www.api.org/~/media/Files/Oiland- Natural-Gas/Natural-Gas-primer/Understanding-Natural-Gas-Markets-Primer-High.pdf.

33 U.S. Energy Information Administration, *U.S. Natural Gas Total Consumption* (Aug. 31, 2020), https://www.eia.gov/dnav/ng/hist/n9140us2A.htm.

34 *Id.* at tbl. 14.

35 AEO 2023 at tbl. 13, line labeled "Consumption by Sector."

36 *Id.* at tbl. 13.

lowest levelized cost of energy ("LCOE") of any source, and the lowest "high" LCOE as well. *See* Appendix K hereto, containing excerpts from the latest Lazard report.

Moreover, combined cycle gas plants cannot stake out a lower "low price" profile than wind *plus storage* (*e.g*., $45). *See* Appendix K, p. 9 of the original. That means that the greater reliability that comes from projects that pair battery storage with wind can outcompete on a cost basis projects planned to be fueled by natural gas.[37]

In other words, the technological evolution of battery storage and renewable generation is displacing natural gas as a fuel for electric generation. Given trendlines to date, it is not surprising that projections of high, medium and low battery costs in the future all continue to decline[38] through 2030 by about 17%, 33% and 50% respectively from current levels according to NREL. But importantly, the disadvantage now facing gas in new U.S. projects exists *today*, as shown in the Lazard report to say nothing of future developments in storage technology. An added disadvantage for new gas-fired generation capacity is that preparing a site for battery installation is usually *much* faster than obtaining the clearance to construct a lateral gas line to a new location.

These economic factors are on display in DOE's latest data. According to EIA, only 2% of all generating capacity added in the first half of this year was fueled by natural gas; about 92% was from wind, solar and batteries. The DOE data show that only about 15% of existing

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37 Renewable sources have no out-of-pocket expense. Solar PV units and wind turbines have a vanishingly tiny incremental cost of dispatching their respective generation equipment. In markets where the merchants typically bid at their avoidable costs, the generation with essentially $0 of incremental cost to dispatch will dispatch more hours, ahead of a resource that has an incremental avoidable cost associated with dispatch.

This argument also does not account for the impact on U.S. gas pipeline rates if demand decreases, meaning the pipeline's cost must be recovered across fewer contracts and lower throughput – a recipe for higher rates for customers and any throughput volumes that remain on the system. *See El Paso Natural Gas Co.,* Opin. No. 528, 145 FERC ¶ 61,040 (2013), Opin. No. 528-A, 154 FERC ¶ 61,120 (2016) Opin. No. 528-B, 163 FERC ¶ 61,079 (2018), *aff'd in pert. part, El Paso Natural Gas Co., LLC v. FERC*, Case Nos. 15-1323 *et al.* (July 24, 2020).

38 NREL 2023 Study, p. iv. *See* Appendix L hereto.

generation capacity fueled by natural gas that was retired was offset by new natural gas-fueled additions during the relevant time period.

New	GW	%
Solar	12.0	59%
Wind	2.5	12%
Battery Storage	4.2	21%
Natural Gas	0.4	2%
Nuclear	1.1	5%
Total	20.2	100%
Retired	GW	%
Coal	2.1	41%
Natural Gas	2.7	53%
Petroleum	0.1	2%
Other	0.2	4%
Total	5.1	100%

Source: DOE EIA - U.S. power grid added 20.2 GW of generating capacity in the first half of 2024

About 95% of capacity anticipated to be added in the second half of the year is also estimated to be solar, wind or battery powered. *Id.*

The EIA estimates that natural gas consumption in the industrial sector will increase to 12.5 Tcf in 2050 from about 10.5 Tcf in 2022 in the Reference case.[39] Natural gas consumption in the commercial sector will decrease 2023-2050, ultimately to 3.45 Tcf in the EIA Reference case.[40] The residential sector is forecasted to experience a -0.2% annual average "growth" in natural gas use, with consumption decreasing from about 5 Tcf in 2023 to about 4.7 Tcf in 2050.[41]

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39 AEO 2023.

40 *Id.*

41 *Id.*

Periodically, there are other claims that electricity demand based on anticipated technological demands that have been wildly overstated. For instance, Berkley National Laboratory subjected a report claiming increased usage associated with the arrival of the internet, to an analysis and concluded that report overstated total "internet-related electricity use by about a factor of eight." *See* Memorandum (LBNL-44698 (12/9/99) memo to Skip Laitier, EPA Office of Atmospheric Programs, from Jonathan Koomey, *et al.*). https://eta-

Even ignoring the fundamental economic drivers manifest in the foregoing data, there is another reason why gas demand in the U.S. will be decreasing: policies and laws at state and local levels favoring renewable sources, and large consumers' statements regarding their demand. For example, in California, all new residential construction must have photovoltaic panels installed. The state's goal is to generate 50% of its electricity from renewable sources by 2030.[42]

In New York, the New York State Energy Research and Development Authority relates that:

> New York's electric grid will be zero-emission by 2040, . . . through an extensive network of wind, solar, hydro power, and energy storage. Residents and businesses will continue receiving support to adopt clean energy technologies, such as heat pumps, to promote affordable electrification while phasing out the use of natural gas.[43]

The State subsequently has been denying permits for new gas plants.[44]

Michigan will go carbon free by 2040 and some municipalities' goal is to get there 10 years earlier. "Mich. City offers new model for 100% clean power."[45] Colorado is on track to essentially bar generation producing air emissions by 2040.[46] Electric generation must achieve zero emissions of identified gases by statutory deadlines in Illinois' Climate and Equitable Jobs

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publications.lbl.gov/publications/initial-comments-internet-begins-coal. *See* Appendix M hereto.

42 "The California Solar Mandate: Everything You Need to Know," Solar Learning Center https://www.solar.com/learn/california-solar-mandate/ *See* Appendix N hereto

43 NYSERDA web page. https://www.nyserda.ny.gov/Goals-Accelerating-the-Transition *See* Appendix O hereto.

44 October 27, 2021 letter from D. Whitehead, Director of Environmental Permits, NY State Dept. of Environmental Conservation to Ms. Brenda Colella. *See* Appendix P hereto.

45 https://www.eenews.net/articles/mich-city-offers-new-model-for-100-clean-power/#:~:text=city%20offers%20new%20model%20for%20100%25%20clean%20power,-By%20Jeffrey%20Tomich&text=In%20what%20could%20be%20a,to%20coal%20and%20natural%20gas. *See* Appendix Q hereto.

46 "Colorado is on track to nearly zero out power emissions – report" [Energy Wire 11/2/23]. *See* Appendix R hereto.

Act.[47] North Carolina law requires "70% carbon reduction by 2030."[48] The list of states obligated to be 100% carbon free, or 100% renewable, is extensive. *See* Appendix U hereto.

EIA's short term energy outlook shows natural gas consumption in electrical generation growing by only .0086% between 2023 and 2025, while wind generation is projected to grow 8% and solar PV will increase by 48% in just those 3 years. Stated differently, natural gas-fired generation capacity (*not* its use) in the 2023-2025 period will increase by 4.25 GW; wind generation will increase by nearly three times as much, by 12 GW; solar PV generating capacity will increase by 16 times as much, by about 70 GW. March 2024 EIA Short Term Energy Outlook ("STEO") (Table 7). Residential PV solar capacity increases by about 11 GW in the same period. *Id.*

> New utility-scale solar generating capacity is driving our forecast for the strong increase in solar electricity generation in 2024 and 2025. The electric power sector added 19 gigawatts (GW) of solar capacity in 2023 (an increase of 27%), and we expect 36 GW will be added in 2024 and another 35 GW will be added in 2025. . . . The increase in generation from renewable sources, particularly solar, is *likely to reduce generation from fossil fuel sources*. We expect the share of U.S. generation fueled by natural gas will fall from an average of 42% in 2023 to 41% in 2025." [STEO 03/24P, p.12 (emphasis added)]

The disparity within individual regions is even greater. Over the 2022-2025 period ERCOT *natural gas-fired generation will fall by more than 10%.* March 2024 EIA STEO Table 7d Pt 2. In the same period non-hydro renewables gain 54 GW, or 40%. *Id.* In EIA's Southwest region, natural gas falls by 13% (or over 9 GW) and in California, by about the same volume, and an even greater proportion, than the Southwest. Not surprisingly, residential and commercial retail natural gas prices in those census regions fall by 25% and 26%, respectively, during the 2023-2025 period. *Id.* Table 5b. Industrial retail natural gas prices fall by about 8% in 2024 and

[47] *See* Appendix S hetero: Citizens Utility Board analysis of CEJA.

[48] Spectrum News 10/13/21 (HB 951). https://spectrumlocalnews.com/nc/charlotte/politics/2021/10/13/north-carolina-has-a-new-clean-energy-law--here-s-what-s-in-it. *See* Appendix T hereto.

increase in 2025, ultimately by about 17% above the 2023 price. *Id.*

In West Texas, for instance at Waha, prodigious production increases led to occasional *negative natural gas prices* [*Gas Daily*, 4/12/24, pp. 5-6]. Some participants forecast flaring in the Permian Basin. *Gas Daily* 4/12/24, p.5. The addition of more pipeline takeaway capacity is anticipated to ease constraints, but only "until late 2026," *Gas Daily*, 4/4/24, p. 4, when production again outpaces takeaway capacity.

Moreover, lower natural gas prices *in the U.S.* are unlikely to further displace coal-fired generation, according to DOE:

> We expect the share of U.S. generation fueled by natural gas will fall from an average of 42% in 2023 to 41% in 2025, while the U.S. coal generation share falls from 17% last year to 14% by 2025. *Low natural gas prices are not likely to lead to significantly more electricity generation fueled by natural gas because significant coal plant retirements over the past few years have left the most efficient coal plants still in operation, which we expect will mostly continue running even if natural gas prices are low.* Nearly 20% of U.S. coal-fired generating capacity has been retired since 2020, the last time natural gas prices were as low as they are now, and the remaining coal fleet has been operating at historically low capacity factors. [03/24 STEO, p. 12; emphasis added]

The larger situation is illustrated by EIA's data, showing decreasing real natural gas prices and declining domestic demand. In light of the substantial addition of resources overwhelmingly projected in domestic natural gas supplies, there are more than sufficient natural gas resources to accommodate both domestic demand and the exports proposed in this Application throughout the term of the requested authorization.

1. Effects on Domestic Prices of Natural Gas

The annual average Henry Hub spot price for natural gas fell from $8.86 per MMBtu in 2008 to $2.56 per MMBtu in 2019.[49]

[49] U.S. Energy Information Administration, *Henry Hub Natural Gas Spot Price* (Sept. 16, 2020),

NERA updated prior studies on price impacts ("NERA Study") examining the probability and macroeconomic impact of various lower-48 sourced LNG export scenarios.[50] Like the prior studies the DOE/FE has commissioned, the NERA Study examined the impacts of varying levels of LNG exports on domestic energy markets. However, the NERA Study also assessed the likelihood of different levels of "unconstrained" LNG exports (defined as market determined levels of exports) and analyzes the outcomes of different LNG export levels on the U.S. natural gas markets and the U.S. economy as a whole, over the 2020 to 2050 time period.

Specifically, the NERA Study developed 54 scenarios by identifying various assumptions for domestic and international supply and demand conditions to capture a wider range of uncertainty in the natural gas markets.[51] "Throughout the entire range of scenarios, [the NERA Study found] that overall U.S. economic output is higher whenever global markets call for higher levels of LNG exports, assuming that exports are allowed to be determined by market demand."[52] According to the 2023 AEO projections, natural gas prices stated in real terms at Henry Hub in 2022 dollars would show an *annual* decrease of <1.9%>, from $6.52 MMBtu to $3.77 MMBtu in 2050. DOE Table 13, "Natural Gas Supply, Disposition, and Prices," This occurs while LNG exports from the U.S. more than double. *See* Table 13, line labeled "Liquefied Natural Gas," 2022-2050. Further, the NERA Study found that "[f]or each of the supply scenarios, higher levels of LNG exports in response to international demand consistently

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https://www.eia.gov/dnav/ng/hist/rngwhhda.htm. The average Henry Hub spot price for January through July of 2020 was approximately $1.80. *Id.*

50 NERA Economic Consulting, *Macroeconomic Outcomes of Market Determined Levels of U.S. LNG Exports*, at 14 (June 7, 2018), https://www.energy.gov/sites/prod/files/2018/06/f52/Macroeconomic%20LNG%20Export%20Study%202018.pdf. [hereinafter LNG Export Study]; *see* "Study of Macroeconomic Outcomes of LNG Exports: Response to Comments Received on Study," 83 Fed. Reg. 67251 (12/28/18).

51 The NERA Study analyzed "the robustness of unlimited market level determined LNG exports by examining different scenarios that reflect a wide range of natural gas market conditions, where robustness is measured using key macroeconomic metrics such as GDP, aggregate household income, and consumer welfare." *Id.* at 13.

52 *Id.* at 14.

lead to higher levels of GDP. . . . Consumer welfare, expressed in dollar terms, is also higher when there is greater domestic . . . gas supply" and higher levels of LNG exports.[53]

EIA's 2023 study of the effects of LNG exports on U.S. market circumstances points to the conclusion that even in the most ambitious export scenario, aggregate price impacts in the electricity market were about 1¢/Kwh. More striking is the fact that in the most ambitious export scenario, natural gas' share of electric generation markets would fall from a 2018-2022 range of 34-40% to only 19%. ["Issues in Focus: Efforts of [LNG] Exports . . .," p. 2]. "In the electric power sector . . . sources such as renewables plus battery storage [are] a viable alternative source for natural gas when natural gas prices rise." *Id*., p. 3.

As demonstrated above, the overall balance between the domestic supply and demand forecasts for the U.S. natural gas market demonstrates that the volumes proposed to be exported in this Application are not needed by the domestic market. This lack of domestic need, combined with the minimal impacts to U.S. prices that exports to non-FTA countries are projected to have, likewise demonstrates that the export of such volumes is not inconsistent with the public interest.

Thus, U.S. natural gas demand is being diminished by renewables, and natural gas will not further diminish coal use in electric generation in the U.S. Prices for natural gas in the U.S. market continue to be lower than those of most other major gas-consuming countries.[54]

C. Other Public Interest Considerations

1. Increased Exports and International Trade

Studies have shown that increased U.S. exports of natural gas "will improve the U.S.

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53 *Id*. at 18, 20.

54 *See, e.g.,* The World Bank, *World Bank Commodities Price Data (The Pink Sheet)* (Sept. 2, 2020), http://pubdocs.worldbank.org/en/451141599073982216/CMO-Pink-Sheet-September-2020.pdf (the average natural gas price in August 2020 was $2.29 per MMBtu in the United States, while the average price in Europe was $2.86 per MMBtu and the average LNG price was $7.79 per MMBtu in Japan).

balance of trade and result in a wealth transfer into the United States."[55] European sales produce significant price premia relative to the U.S.[56]

Additionally, LNG exports provide important geopolitical benefits by diversifying global energy supply. In the Policy Statement, DOE/FE recognized that "[a]n efficient, transparent international market for natural gas with diverse sources of supply provides both economic and strategic benefits to the United States and its allies" and that "to the extent U.S. exports can diversify global LNG supplies and increase the volumes of LNG available globally, these exports will improve energy security for many U.S. allies and trading partners."[57] That is especially so as global tensions have escalated in Europe and in Asia in recent years. U.S. energy supplies are vital in supporting our allies in both regions. Access to energy sourced from the U.S. helps fortify political, economic and military ties between other countries and the U.S., rather than forcing them into reliance on sources that do not favor the United States and in fact may use hydrocarbon sales revenue to undermine the U.S. The authorizations requested herein will further these international trade and geopolitical benefits.

A decision to prohibit exports of natural gas for the Project would cause the United States to forego the economic and international benefits discussed herein.

In sum, the public interest is advanced by granting the requested authorization.

VI. REVIEW OF ENVIRONMENTAL EFFECTS

A. This Application Should be Subject to a Categorical Exclusion under NEPA

According to DOE, its

> review of applications for LNG exports to non-FTA countries is limited to consideration of effects that are reasonably foreseeable

[55] 2018 LNG Export Study at 64.

[56] *See Platts Gas Daily*, Apr. 12, 2024, "Europe pulling U.S. LNG cargo is boost to storage as injection season starts," citing "high premiums for European LNG prices over US Henry Hub values."

[57] Policy Statement, 85 Fed. Reg. at 52244.

> and have a sufficiently close causal connection to the granting of the export authorization. DOE [established a] . . . [C]ategorical [E]xclusion . . . B5.7 to focus exclusively on the analysis of potential environmental impacts resulting from activities occurring at or after the point of export, which are within the scope of DOE's export authorization authority under the NGA.

National Environmental Policy Act Implementing Procedures, Final Rule ("NEPA RM") 85 C.F.R. 78197 (footnotes omitted).

In sum, "DOE's analysis is properly limited to impacts stemming directly from decisions made pursuant to its statutory authority." [NEPA RM at 78201]. "[C]onsistent with the CEQ regulations, and the legal principle enunciated in *Public Citizen* and *Sierra Club* . . . potential environmental effects considered under NEPA do not include effects that the agency has no authority to prevent." *Id*. at 78198 (citations omitted).

Thus, Gato Dos respectfully requests that the DOE/FE determine that a categorical exclusion from the requirement to produce an environmental assessment and/or an environmental impact statement ("EIS"), is both applicable and appropriate for DOE/FE's review of the export volumes requested here. Application of a categorical exclusion in this case is appropriate because the Manzanillo Plant will be located in Mexico, beyond the scope of the DOE/FE's jurisdiction. Further, under DOE/FE established practice, the existing physical pipeline capacity in the U.S. exceeds the volumes Gato Dos is requesting to export to Mexico, meaning the categorical exclusion should apply.

Accordingly, under the relevant DOE regulations and DOE/FE precedent, the requested exports associated with the Project are not expected individually or cumulatively to have significant negative environmental impacts in the United States.[58]

The regulations adopted by the Council on Environmental Quality ("CEQ") state that the

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[58] Categorical exclusions apply in the case of actions the implementing agency has determined are not expected to have individually or cumulatively significant environmental impacts. *See* 40 C.F.R. § 1508.4.

application of categorical exclusions to certain categories of actions is appropriate where the implementing agency has determined such actions are not expected to have individually or cumulatively significant environmental impacts.[59] DOE regulations implementing NEPA have recognized Categorical Exclusion B5.7, generally exempting "[a]pprovals … of new authorizations . . . to. . . export natural gas under section 3 of the Natural Gas Act that involve minor operational changes (such as changes in natural gas throughput, transportation, and storage operations) but not new construction."[60] Consequently,

> " 'indirect effects pertaining to increased gas production were not reasonably foreseeable' and therefore not subject to NEPA review. [Where] 'the Department could not estimate the locale of production, it was in no position to conduct an environmental analysis of corresponding local-level impacts, which inevitably would be more misleading than informative.' The . . . effects must be 'reasonably foreseeable and have a reasonably close causal relationship to the proposed action' to be considered under NEPA, . . . [and the] 'effects should generally not be considered if they are remote in time, geographically remote, or the product of a lengthy causal chain.' Under this standard, consideration of upstream impacts is not required." [NEPA RM at 78201].

DOE has not considered "potential upstream and downstream impacts as part of its NEPA analyses for natural gas export approvals." Induced upstream production impacts are not reasonably foreseeable for NEPA purposes, and are therefore not "effects" subject to analysis under NEPA. NEPA RM at 78200. *See* Appendix E.

Construction of the Project facilities will occur entirely in Mexico. Furthermore, the physical capacity of the existing cross-border pipeline facilities along the U.S./Mexican border exceeds the proposed export volumes. If future pipeline facilities are required to further serve the Project they will be reviewed in due course, for instance for Presidential Permit purposes under NGA Section 3.

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[59] *See* 40 C.F.R. § 1508.4.

[60] 10 C.F.R. Part 1021, Subpart D, app. B § B5.7 (emphasis added).

The DOE/FE has served as a cooperating agency in FERC's NEPA review process associated with the construction of LNG export projects *located in the United States*. However, in the case of the Project, construction and operation of Project facilities will occur in Mexico. The environmental effects of construction and operation of the Project facilities are already being reviewed by Mexican regulators, *see* Part III.C., *supra*, under their own environmental rules for the Project. Environmental impacts connected to the Project in Mexico will be considered by the appropriate Mexican authorities.[61]

A finding that Categorical Exclusion B5.7 applies to exempt the Application from review under NEPA would be consistent with the conclusion that the DOE/FE reached in other instances where it has reviewed proposals to export U.S. gas to a foreign country for re-export to non-FTA countries. In DOE/FE Order No. 3768, DOE found that Categorical Exclusion B5.7 was applicable because the only construction proposed would occur outside of the United States, which was "beyond the scope of [DOE's] environmental review under NEPA."[62] Order No. 3768, confirmed that an environmental analysis of construction outside of the United States "is outside the scope of [DOE's] environmental review under NEPA . . . which necessarily focuses on potential environmental impacts within the United States."[63]

DOE has determined that its decision-making process is better when "focusing its NEPA review on those activities that are within DOE's authority under the NGA," *id*. at 78198, as opposed to " . . . considering the potential environmental effects from activities that are beyond

61 "DOE need not review potential environmental impacts associated with the construction or operation of natural gas export facilities because DOE lacks authority to approve the construction or operation of those facilities. DOE's review is properly focused on potential environmental impacts resulting from the exercise of its NGA section 3 authority. These potential impacts would occur at or after the point of export to non-FTA countries." NEPA RM at 78198.

62 *Pieridae Energy* (*USA*) *Ltd*., FE Docket No. 14-179-LNG (Feb. 5, 2016), DOE/FE Order No. 3768 ("Order No. 3768") at 202.

63 DOE/FE Order No. 3768 at 190.

its decision-making authority, such as LNG terminal construction and operation." *Id.*, at 78199. *See also, id*. at 78201.

"DOE believes it is appropriate for its NEPA review of natural gas export applications to consider the potential environmental impacts starting at the point of delivery to the export vessel, and extending to the territorial waters of the receiving country." *Id.*, 78199. Based on that perspective, "DOE has determined that transport of natural gas by marine vessel normally does not pose the potential for significant environmental impacts." NEPA RM at 78198. As noted above, the shorter shipping route to Pacific markets from Manzanillo (rather than the U.S. Gulf Coast) results in reduced marine vessel emissions.

Furthermore, downstream emissions at the point of consumption are too attenuated to be reasonably foreseeable and do not have a reasonably close causal relationship to the granting of an export authorization." *Id.*, 78200. DOE agreed that consumption market "subject matter falls outside DOE's NEPA review obligations because the regasification and ultimate burning of LNG in foreign countries are beyond the scope of DOE requirements under NEPA." *Id.*, 78200. The topics of "regasification and ultimate combustion of regasified U.S. LNG in foreign countries are beyond the scope of appropriate NEPA review in this context." NEPA RM at 78202.[64]

The non-FTA export volumes would use the pipeline capacity otherwise used by Applicant's affiliates to make LNG sales to FTA countries.[65] Hence, there is no greater

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[64] Should the DOE reconsider this ruling (1) any such reconsideration would have to occur in a procedurally valid manner, and (2) would have to consider substantial evidence that combustion overseas would be beneficial because it displaces (directly or indirectly) less environmentally-friendly fuels. *See*, *e.g*., Appendices F, G and H.

[65] 10 C.F.R. § 1021.410(b)(3). DOE/FE is also required to consider whether there are any extraordinary circumstances related to the proposal that may affect the significance of the environmental effects of the proposal. Id. § 1021.410(b)(2). Extraordinary circumstances are defined as "unique situations presented by specific proposals, including, but not limited to, scientific controversy about the environmental effects of the proposal; uncertain effects or effects involving unique or unknown risks; and unresolved conflicts concerning alternative uses of available resources." *Id*. As noted above, the Project involves no construction of facilities in the United States and will therefore have no environmental effects requiring NEPA review. Accordingly, there

cumulative impact than would arise because of the sales that would otherwise be made to FTA markets. In other words, non-FTA sales would preclude the same volume of sales that could otherwise be made to FTA markets.

B. Alternatively, Applicant Shows The Project Should Be Authorized Using An EA Analysis

If, despite the foregoing arguments, DOE/FECM determines that an EA is necessary for the Project, the Project nonetheless should be approved.

1. Summary

The DOE reviews applications for non-FTA export authorization under NGA section 3(a), and authorizes the natural gas exports requested unless it finds that the proposed exports would not be consistent with the public interest.

2. Analysis

a. Alternatives

The Proposed Action of granting the requested export authorization to Gato Dos should be compared to a No Action Alternative in which the requested authorization would not be granted.

b. Proposed Action

Gato Dos filed the instant Application in connection with its continuing development of the Manzanillo Plant. Once completed, the Manzanillo Plant will be capable of receiving, processing, and liquefying natural gas, storing the resulting LNG, and loading LNG onto oceangoing LNG carriers for re-export to other countries and, potentially, for delivery to markets elsewhere in Mexico.[66] In its FTA Application,[67] Gato Uno previously sought authorization to

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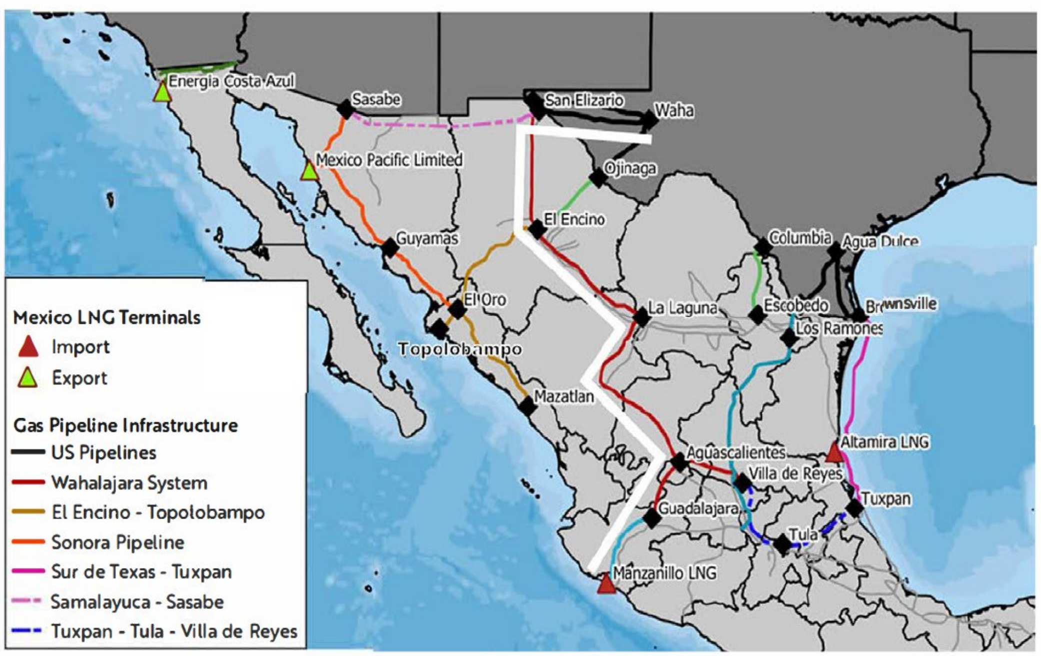
can be no extraordinary circumstances affecting the significance of environmental effects.

[66] *See* p. 6, *supra* and p. 50, *infra*..

[67] DOE/FECM Docket No. 24-43-LNG.

export up to the equivalent of .647 billion cubic feet (Bcf) per day (Bcf/d) of U.S.-sourced natural gas to Mexico for end use in Mexico and/or, after liquefaction in Mexico, for export by vessel from the proposed Manzanillo Plant to FTA nations.[68] In the instant Application Gato Dos is seeking authorization to export .647 Bcf/d of natural gas to Mexico by pipeline from the U.S. and authorization to re-export from those volumes .556 Bcf/d, or 202.94 Bcf annually for non-leap years, as LNG to non-FTA countries, extending through December 31, 2050. The two authorizations contemplate the use of the same pipeline and liquefaction capacity. Hence, every btu on a given day sent by Gato Uno to FTA countries would reduce the pipeline transportation and the liquefaction capacity that Gato Dos could use to make sales to a buyer in a non-FTA country.



Note: Map only contains a subset of current and pending pipelines

[68] *See* DOE/FECM Docket No. 24-43-LNG Application at p. 6.

i. Natural Gas Supply and Transportation

Gato Dos plans to source natural gas from a variety of U.S. producing basins.[69] Gato Dos will export natural gas to Mexico via existing cross-border gas transmission pipelines, including an interstate natural gas pipeline owned by Sierrita Gas Pipeline LLC, and intrastate natural gas pipelines owned by Comanche Trail Pipeline, LLC, Roadrunner Gas Transmission, LLC and Trans Pecos Pipeline, LLC, all located in west Texas.[70] Further, the available pipeline capacity in both the U.S. and Mexico is more than adequate to support the requested exports to the Manzanillo Plant.[71] Moreover, the Saguaro pipeline is planned in addition to the several existing natural gas transportation route options that could transport volumes to the Manzanillo Plant.[72]

Gato Dos anticipates substantial, although not necessarily exclusive, purchases in Texas.[73] Gato could acquire natural gas supplies via several different pipeline routes.

ii. Liquefaction Facility

The Manzanillo Plant is under development in Manzanillo, Mexico, a port on the Pacific Ocean. The Plant's capacity would be .556 Bcf/d. If demand warrants, a second phase of the project would be constructed, and related export authorizations would be subject to a separate application. Gato Dos also plans to use LNG storage capacity and to build a port terminal. Construction is planned to commence in 2026 if the requested authorization is granted by DOE/FECM in February 2025. Gato Dos is requesting authorization to export to non-FTA nations a maximum volume of LNG of .556 Bcf/d.

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69 *See supra* at p. 6.

70 *Id*. at p. 7.

71 *Id*. at pp. 7-8 and Appendix H.

72 Saguaro was issued a Presidential Permit and NGA Section 3 authority in February 2024. *See* "Order Issuing Presidential Permit and Granting Authorization under Section 3 of the Natural Gas Act", *Saguaro Connecter Pipeline, LLC*, 186 FERC ¶61,114 (2024). It accepted its authorization and its terms on March 13, 2024.

73 *See* p. 6, *supra*.

iii. Target Markets

Gato Dos envisions its primary end use markets will be in Asia.

iv. No Action Alternative

If the Application is not granted, Applicant respectfully requests that DOE assume, for the purposes of this EA, that Gato Dos would not contract for sales to non-FTA countries and the potential environmental impacts from Gato Dos would not occur. However, global demand for natural gas, including demand for LNG, is expected to grow, even accounting for the transition away from fossil fuels.[74] It is therefore likely that some or all of the demand for LNG that Gato Dos is intended to serve would be met by other LNG facilities, if the requested authorization were not to be granted.

3. Scope of Environmental Assessment

a. Extraterritorial Impacts

The environmental impacts subject to analysis in this EA are limited to those direct and indirect impacts that would occur in the United States and those that affect the global commons, such as global climate change resulting from emissions of greenhouse gases (GHGs). An EA would not analyze potential environmental impacts associated with elements of the Application that would occur within the sovereign territory of Mexico or any other country aside from the United States. These include the potential local and regional impacts of pipeline transportation of natural gas within Mexico to the Manzanillo Plant, and incremental operation of the

[74] Several forecasting entities project continued growth in natural gas demand. For example, the Energy Information Administration (EIA) International Energy Outlook 2023 projects global natural gas consumption to increase by more than 29% from 2022 to 2050, in its Reference Case, even as it projects renewable power to become the largest electric generation source. *See* EIA, International Energy Outlook 2023, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=20-IEO2023&region=6-0&cases=Reference&start= 2020&end =2050&f=A&linechart=Reference-d230822.1-20-IEO2023.6- 0&sourcekey =0. McKinsey has also projected LNG demand growth averaging 3.4% per year to 2035, with continued growth of 0.5% per year through 2050. The firm's accelerated transition scenario still shows an increase in demand only slightly lower by mid-century. *See* McKinsey, Global Gas Outlook to 2050, Summary Report, at 2 (Feb. 2021), https://www.mckinsey.com/~/media/mckinsey/industries/oil%20and%20gas/our%20insights/global%20gas%20outlook%20t.

Manzanillo Plant in Mexico (including LNG terminal operations) to accommodate non-FTA export volumes, and terminal operations, transport, and use of LNG within receiving non-FTA countries.

NEPA does not require an analysis of environmental impacts that occur within another sovereign nation as the result of actions approved by that sovereign nation. Executive Order (E.O.) No. 12114 requires federal agencies to prepare an analysis of significant impacts from a federal action in certain defined circumstances and exempts agencies from preparing analyses in others. The E.O. does not require federal agencies to evaluate impacts outside the United States when the foreign nation is participating with the United States or is otherwise involved in the action.[75] The Manzanillo Plant would be used in connection with this application and would be sited in Mexico, where it would have to be constructed and sited in accordance with all applicable Mexican laws, regulations, and standards. Additionally, aside from the life cycle emission of GHGs and the marine transport of LNG in international waters, the federal action would not affect the global commons.

b. Summary of Mexico's Environmental Review Process

The Manzanillo Plant facilities and appurtenant pipeline facilities, constructed in Mexico, are subject to review and approval by Mexican agencies under federal laws of that nation. While Mexico's review process falls outside the scope of this EA, nonetheless, *see* Part III.C, *supra*.

4. Potential Environmental Impacts

a. Affected Environment

The affected environment is limited to the areas potentially affected by the Proposed Action that are within the scope of the EA, as identified in section II, *supra*.

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[75] *See* E.O. 12114, Environmental effects abroad of major Federal actions, § 2-3(b) (Jan. 4, 1979), https://www.archives.gov/federal-register/codification/executive-order/12114.html.

b. Incremental Natural Gas Production

Potential natural gas sources for Gato Dos include producing basins in the lower-48 states. The U.S. Energy Information Administration (EIA) projects that, by 2030, over 95% of natural gas produced onshore in the lower-48 states will be produced from "unconventional" resources, including gas from tight sandstone formations, gas from shale formations or gas associated with oil in tight formations, and gas from coal beds ("coalbed methane").[76] According to EIA's 2023 Annual Energy Outlook (AEO 2023), the share of onshore natural gas produced from these sources is expected to remain above 95% in 2050.[77] The most likely impacts associated with natural gas production would therefore relate to Gato Dos-induced incremental production of those resources. DOE's environmental study, *Addendum to Environmental Review Documents Concerning Imports of Natural Gas from the United States* (Aug. 2014) (Addendum),[78] incorporated herein by reference, identifies areas potentially affected by unconventional natural gas production, including water resources, air quality, induced seismicity, and land use.[79]

c. Environmental Cross-Border Pipeline Transportation of Natural Gas

As detailed above, Gato Dos anticipates that it will utilize natural gas pipelines, including those specifically enumerated in this Application, to transport natural gas to the Manzanillo Plant from the United States.[80] The authorized export volume requested in the Application will not

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76 *See* EIA, Annual Energy Outlook 2023, Table 14, available at https://www.eia.gov/outlooks/aeo/.

77 *See id*.

78 U.S. Department of Energy, Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States (Aug. 2014), https://www.energy.gov/sites/prod/files/2014/08/f18/Addendum.pdf.

79 The Addendum also addresses potential impacts on upstream GHG emissions (apart from their role in local or regional air quality), but those emissions are addressed holistically with emissions from other life cycle segments in section VI.B.3.e. ("GHG Emissions and Climate Change") below. *See* Appendices E, and G pp. 2-3 hereto.

80 *See* pp. 7-8, *supra*.

involve or require the construction of any U.S. facilities that would yield environmental effects cognizable under NEPA.[81] Natural gas transported on behalf of Gato Dos would increase utilization of pipelines, and therefore has the potential to cause incremental impacts in emissions related to pipeline operations. (These potential impacts are addressed below.)

There is a significant and growing natural gas pipeline supply infrastructure between producing basins in the Southwestern and Gulf Coast regions of the U.S. and northern Mexico. EIA has data depicting existing cross-border pipeline connections.[82] Appendix H provides details about the relevant pipelines, including the border crossing location and average export data for 2022.

d. Marine Transportation of LNG

Exports from Gato Dos would occur via ocean transport. The potentially affected environment in marine transportation of LNG includes resources that could be impacted by a release of the LNG cargo, in liquid or gaseous form, as well as routine shipping-related risks, such as fuel leaks and engine emissions. These resources include the ocean environment and the atmosphere in the area around an LNG vessel at sea.

e. GHG Emissions and Climate Change

Rising atmospheric GHG concentrations are altering global climate systems with the potential for long- term impacts on human society and the environment. The region of influence (ROI) for GHGs differs from other resource areas considered in this EA, as the concerns about GHG emissions are primarily related to climate change, which is global and cumulative in

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81 *See* pp. 7-8, *supra*.

82 Table 1, Points of Entry/Exit, https://www.energy.gov/sites/prod/files/2015/08/f25/POEE%20List.pdf; Natural Gas Intelligence, 2023 Map of North American Pipelines, LNG Facilities, Shale Plays and Market Hubs, https://www.naturalgasintel.com/ngis-north-american-map-of-north-american-pipelines-lng-facilities-shale-plays/#options; EIA, U.S. Natural Gas Exports and Re-Exports by Point of Exit, https://www.eia.gov/dnav/ng/ng_move_poe2_a_EPG0_ENP_Mmcf_a.htm; https://ienova.gcs-web.com/static-files/1ba71478-c5cf-424c-9c2a-38ff0de6f0da.

nature.

Increasing GHG concentrations in the atmosphere are linked to a range of ongoing and potential changes to global climate. Assessments of future climate change are dependent on predicted trends in GHG emissions, which depend on future policy and other actions to reduce GHG emissions. Climate change is linked to rising surface temperatures, changing levels of precipitation, reduction in sea ice cover, increasing ocean temperature, and rising sea levels. Climate change can result in changes in ecosystems, as well as an increase in the frequency and severity of extreme weather events, and can impact human health and society.

5. Potential Impacts

a. Natural Gas Production

The natural gas to be liquefied and exported by Gato Dos would be produced from natural gas wells in the lower-48 states. As noted *supra*, a majority of onshore natural gas produced in the lower-48 United States is from unconventional resources.

i. Proposed Action

On August 15, 2014, DOE published the Addendum.[83] DOE prepared the Addendum to be responsive to the public and to provide the best information available on a subject that had been raised by commenters in LNG export application dockets. The Addendum addresses unconventional natural gas production in the lower-48 states. It does not attempt to identify or characterize the incremental environmental impacts that would result from LNG exports to non-FTA countries.[84]

The Addendum determined that the current rapid development of natural gas resources in

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83 *Supra* note 78.

84 *See Sierra Club v. U.S. Dep't of Energy*, 867 F.3d 189, 198–99 (D.C. Cir. 2017) (upholding DOE's conclusion that, without knowing where local production of the incremental natural gas would occur, the corresponding environmental impacts are not reasonably foreseeable under NEPA).

the United States likely will continue, with or without the export of natural gas to non-FTA nations.[85] Nevertheless, a decision by DOE to authorize exports to non-FTA nations could accelerate that development by some increment. The Addendum reviewed the academic and technical literature covering the most significant issues associated with unconventional natural gas production, including impacts to water resources, air quality, GHG emissions, induced seismicity, and land use.

The Addendum shows that there are potential environmental issues associated with unconventional natural gas production that need to be carefully managed, especially with respect to emissions of volatile organic compounds and methane, and the potential for groundwater contamination. However, it is not possible to determine which specific natural gas resources would be produced to serve the Gato Dos, and different gas sources will be affected by local geological circumstances, regional regulations such as zoning/land use rules that vary by governmental subdivision, different chemical and btu content and the uneven pace of infrastructure development. *See Sierra Club, supra,* 867 F.3d at 198-99.

ii. No Action Alternative

In the No Action Alternative, LNG would not be supplied from Gato Dos. In this case, DOE would presume that other LNG facilities would serve incremental international demand for LNG, supplying some or all of the volume planned to be supplied by Gato Dos. Therefore, natural gas could be produced for liquefaction, in the United States or in another country.

If produced in the lower-48 United States for a North American project, any potential impacts related to incremental natural gas production would similarly occur in the No Action Alternative, which would therefore not have a currently identifiable environmental advantage over the proposed action. If produced In the No Action Alternative, LNG would not be supplied

85 Addendum at 2.

from Gato Dos. In this case, DOE may properly conclude that other LNG facilities would serve incremental international demand for LNG, supplying some or all of the volume planned to be supplied by Gato Dos. Therefore, natural gas could be produced for liquefaction, in the United States or in another country.

If produced in the lower-48 United States for a North American project, any potential impacts related to incremental natural gas production would similarly occur in the No Action Alternative, which would therefore not have a currently identifiable environmental advantage over the proposed action. If produced outside of the United States for a foreign LNG project, it would be outside the scope of this analysis to assess impacts from natural gas production.

b. Natural Gas Pipelines

i. Proposed Action

A draft DOE EA from November 2023 considered potential environmental impacts from natural gas pipeline transportation in the lower-48 states. Modifying that analysis for Gato Dos capacity shows that Gato Dos' pipeline capacity, *if used at 100% of the capacity reservation at all times*, would be roughly equivalent to eight-tenth of a percent of U.S. pipeline system throughput in 2022.[86] All of the U.S. pipelines that could potentially transport natural gas to Mexico for Gato Dos' use are under federal or state jurisdiction. They have been, or, in the case of any pipelines that may be under development, are being or will be evaluated by FERC and/or the relevant state regulatory authorities, for environmental and other impacts.[87]

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86 The Application requests authority to export from the U.S. up to 236 Bcf/yr. in non-leap years. EIA reports that the U.S. natural gas transportation network "delivered about 29.1 [Tcf] of natural gas" in 2022 (236 Bcf ÷ 29.1 Tcf, or 29,100 Bcf = .81%). EIA, Natural Gas Explained: Natural Gas Pipelines, https://www.eia.gov/dnav/ng/ng_cons_sum_a_EPG0_vgt_mmcf_a.htm.

87 For information about FERC's regulatory role for natural gas pipelines, see the web page at https://www.ferc.gov/industries-data/natural-gas/overview/natural-gas-pipelines#:~:text=FERC%20itself%20has%20no%20jurisdiction,needed%20pipelines%20and%20related%20facilities. For information regarding environmental reviews of any of the pipelines listed in Appendix B, *see* FERC's eLibrary at https://elibrary.ferc.gov/eLibrary/search.

Incremental pipeline throughput would not increase the flow of natural gas to levels above those permitted by FERC and/or state regulatory authorities, for existing or future pipelines. Incremental natural gas flow caused by Gato Dos' demand would therefore not be expected to cause environmental effects that exceed permitted levels.

DOE also considered pipeline safety and accidental emissions. Potential impacts relevant to this EA are any impacts associated with the operation of pipelines that might be incrementally greater with marginally higher throughput due to Gato Dos' demand. The Pipeline and Hazardous Materials Safety Administration (PHMSA) develops and enforces regulations for the safe, reliable, and environmentally sound operation of the Nation's pipeline transportation system.[88]

PHMSA incident reports submitted by companies that operate U.S. pipelines connecting at border crossings between the U.S. and Mexico shows that, from January 2010 through August 2023, these companies submitted a total of 94 incident reports for their entire operations. These 94 incidents resulted in about 2 Bcf of gas emissions over the 13-year time period studied. "Equipment failure" is noted as the most common cause, accounting for 44% of the incidents.

Of these 94 incident reports posted by PHMSA, nine were reported to be located in counties associated with border crossing locations: one in Arizona and eight in Texas. Judging by the locations of eight of the nine incidents, they could be (but are not necessarily) associated with equipment/operations supporting pipeline crossings. Five of these eight incidents were reported for a single company's infrastructure relatively close to the pipeline border crossing near Laredo, Texas, all due to malfunction of control/relief equipment. However, as of August 2023, there were no incidents reported to PHMSA at locations near that border crossing since

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88 For information on PHMSA's role in ensuring the safe operation of natural gas pipelines, *see* https://www.phmsa.dot.gov/regulations.

April 2018.

These data reflected incidents reported by companies operating pipelines that connect to cross-border interconnections along the Mexico-U.S. border, from January 2010 through August 2023, that are located within the same county as a pipeline border crossing.

Conservatively assuming the eight incidents close to the border crossings were directly related to operations at those crossings, a little more than 67 million cubic feet (MMcf) of gas would have been emitted during the time period from January 2010 through August 2023, mostly due to equipment malfunctions. According to EIA data, from January 2010 through August 2023, approximately 18.06 Trillion cubic feet (Tcf) of natural gas was exported via pipeline to Mexico.[89] That would equate to the accidental emission of less than one-one thousandth of one percent[90] of total exported gas during this period, well below current estimates of average methane emissions associated with natural gas transport across U.S. natural gas infrastructure.[91] This would be an upper bound estimate, based on an assumption that all of these emissions were directly associated with cross-border transport.

ii. No Action Alternative

If Gato Dos was not authorized, any potential local or regional impacts associated with incremental pipeline transportation of natural gas for Gato Dos would not occur. Nonetheless,

89 EIA, U.S. Natural Gas Pipeline Exports to Mexico, https://www.eia.gov/dnav/ng/hist/n9132mx2M.htm (last accessed Nov. 20, 2023).

90 The more exact figure is 0.000372%.

91 The EPA's 2023 GHG Inventory (GHGI) states that methane emissions from U.S. natural gas transport and storage activities in 2021 totaled about 44.5 million metric tons CO2-e (1590 kilotons of CH4): https://www.epa.gov/system/files/documents/2023-04/US-GHG-Inventory-2023-Main-Text.pdf (Tables 3-66 and 3-67). This is equivalent to about 82.55 Bcf of methane. EPA Conversion tables: https://www.epa.gov/cmop/coal-mine-methane-units- converter#metricTons. This translates to a loss of 0.002 cubic feet of methane emitted to the atmosphere per cubic foot of natural gas transported—about 0.2%, since natural gas is mostly methane. Researchers have proposed that, based on comparisons of "top down" atmospheric measurements with the EPA's GHGI "bottom up" measurements, actual methane emissions may be 60 to 70 percent higher than the EPA estimates (https://www.iea.org/news/methane-emissions-from-the-energy-sector-are-70-higher-than-official-figures; https://www.edf.org/climate/methane-studies), so a worst case scenario might be 0.33%. A loss of 0.000372 percent is well below this figure.

alternative incremental LNG production capacity constructed in North America using natural gas from the lower-48 states, would yield similar local or regional impacts to gas supplied to Gato Dos (although at different locations in the United States), and the No Action Alternative would not have a currently identifiable environmental advantage over the Proposed Action. Locating the LNG plant in the U.S. would also require measuring impacts by (*e.g.*, environmental justice) on U.S. residents, which would not occur in the U.S. by virtue of the Manzanillo Plant. If incremental liquefaction capacity were developed outside of the United States, impacts associated with pipeline transportation would occur within a sovereign foreign country and would therefore be outside the scope of this analysis.

c. Marine Transport of LNG

i. Proposed Action

As part of a NEPA rulemaking finalized on December 4, 2020,[92] DOE conducted a detailed review of technical documents regarding potential effects associated with marine transport of LNG.[93] These documents were identified in an accompanying Marine Transport Technical Support Document (Technical Support Document), which is incorporated herein by reference.[94] On the basis of the data referenced in the Technical Support Document, DOE concluded that "the transport of natural gas by marine vessels adhering to applicable maritime safety regulations and established shipping methods and safety standards normally does not pose the potential for significant environmental impacts."[95]

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92 *See* U.S. Dept. of Energy, National Environmental Policy Act Implementing Procedures, Final Rule; 85 Fed. Reg. 78,197 (Dec. 4, 2020).

93 *Id*. at 78,199.

94 *See id*. at 78,198 n.16 (citing U.S. Dept. of Energy, Technical Support Document, Notice of Final Rulemaking, National Environmental Policy Act Implementing Procedures (10 C.F.R. Part 1021) (Nov. 2020)).

95 *Id*. at 78,200; *see also id*. at 78,202. In the 2014 LCA GHG Report and 2019 Update, DOE also considered how emissions associated with the ocean transport of U.S. LNG in tankers contribute to total life cycle GHG emissions.

Moreover, total marine transport fuel that otherwise would be associated with transport from the U.S. Gulf Coast to Asian markets would be reduced by using the closer Manzanillo Plant located on the Pacific Ocean. Notably, the 2019 NETL Update (referenced in Part VI.B.5.d.1, *infra*) presumed that the LNG would be shipped to Asia from New Orleans, rather than from the much closer port of Manzanillo. The specific LNG export/import locations used in that study were chosen to represent an estimate for a region (*e.g.*, New Orleans as U.S. Gulf Coast). *See* 2019 GHG Report at 29-30, 32. For this Project, tanker fuel used for LNG transport would be lower than the tanker fuel presumed in the 2019 GHG Report. The study has concluded that "[t]he U.S. LNG to Europe and Asia and the Australia LNG scenarios do not overlap the regional coal scenario on a 20-yr time horizon." [2019 NETL Update, p. 21]

If Gato Dos did not become operational, some or all of the volume of LNG Gato Dos would have exported could be supplied to markets from other sources. Although varying with transportation distance (which could be shorter or longer), these impacts would be similar to those identified in the Marine Transport Technical Support Document.

d. GHC Emissions

i. Proposed Action

DOE's National Energy Technology Laboratory (NETL) conducted a study in 2014, updated in 2019 (collectively, "GHG Studies"), of GHG emissions attributable to LNG exports from the lower-48 states, to inform decisions on applications to export natural gas from the lower-48 states in the form of LNG to non- FTA countries. The findings of the GHG Studies are applicable to assessment of the GHG emissions related to the exports proposed in the instant Application. DOE's study of Life Cycle GHG emissions provides sufficient consideration of these emissions.

In 2014, NETL published Life Cycle Greenhouse Gas Perspective on Exporting

Liquefied Natural Gas from the United States (2014 LCA GHG Report).[96] The 2014 LCA GHG Report calculated the life cycle GHG emissions for LNG made from natural gas sourced from the lower-48 states and exported to markets in Europe and Asia. DOE commissioned the life cycle analysis (LCA) to inform its review of non-FTA applications, as part of its broader effort to evaluate different environmental aspects of the LNG production and export chain. The 2014 LCA GHG Report concluded that the use of U.S. LNG exports for power production in European and Asian markets would not increase global GHG emissions from a life cycle perspective, when compared to regional coal extraction in the global regions near the point of consumption, and consumption for power production.

In 2019, NETL updated the 2014 LCA GHG Report, entitled Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas From the United States: 2019 Update (2019 Update).[97] The conclusions of the 2019 Update were consistent with those of the 2014 LCA GHG Report—that, "[w]hile acknowledging uncertainty, to the extent U.S. LNG exports are preferred over coal in LNG- importing nations, U.S. LNG exports are likely to reduce global GHG emissions on a per unit of energy consumed basis for power production."[98] Additionally, "to the extent U.S. LNG exports are preferred over other forms of imported natural gas, they are likely to have only a small impact on global GHG emissions."[99] Both the 2014 LCA GHG Report and the 2019 Update are incorporated herein by reference.

It is reasonable to apply the GHG Studies in reviewing the life cycle emissions related to

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96 U.S. Dept. of Energy, Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas From the United States, 79 Fed. Reg. 32,260 (June 4, 2014).

97 Nat'l Energy Tech. Lab., Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States: 2019 Update (DOE/NETL-2019/2041) (Sept. 12, 2019), https://www.energy.gov/sites/prod/files/2019/09/f66/2019%20NETL%20LCA-GHG%20Report.pdf.

98 U.S. Dept. of Energy, Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas From the United States: 2019 Update – Response to Comments, 85 Fed. Reg. 72, 85 (Jan. 2, 2020).

99 *Id.*

exports proposed in the Application. The source of natural gas for Gato (the lower-48 states) is the same source analyzed in the GHG Studies. Pipeline transport within the U.S. would also be comparable. Emissions from pipeline transport including a segment in Mexico could differ from U.S. pipeline emissions estimates in the GHG Studies for two reasons: 1) the total transport distance may be longer due to the Manzanillo Plant's location compared to a U.S. Gulf Coast location, and 2) GHG emissions from pipelines in Mexico may be different than emissions from U.S. pipelines. The extent of such a potential difference is uncertain, but a sensitivity analysis of pipeline emissions values in the GHG Studies can reasonably estimate a range of possible divergence from the GHG Studies' findings.

DOE should find that Gato Dos is reasonably comparable to the representative LNG Project analyzed in the GHG Studies. Marine shipments of LNG from Gato Dos would have similar attributes to shipments from the U.S. Gulf Coast location analyzed in the GHG Studies. As noted above, this Application emphasizes exports to Asian markets, and so transport to that region properly should be the focus of DOE's assessment here, although the Application allows for exports to other markets as well. The shorter distance to markets in Asia would lead to lower marine transport emissions from LNG shipping from Gato Dos, as compared to exports from a Gulf Coast location.

Results from the 2019 Update for each segment of the life cycle analysis, for that study's representative Asian market (Shanghai, China), are shown in Table 4 below.[100] Because the GHG Studies examined use of fuels for power generation as a basis of comparison, emissions rates were expressed in terms of the amount of carbon dioxide-equivalent (CO2-e) of GHGs emitted per unit of electricity generated -- carbon dioxide-equivalent emissions per megawatt-

[100] 2019 Update, Exhibit A-2, p. A-2.

hour (CO2-e/MWh).

Process Element	100-yr GWP
Natural Gas Extraction	21
Gathering and Boosting	50
Processing	18
Pipeline Transport	60
Liquefaction	41
Tanker Transport	76
LNG Regasification	4
Power Plant Operations	416
Electricity T&D	2
Total	688
Low	663
High	763

Table 4. Life cycle GHG emissions (100-yr GWP) for U.S. LNG shipped from New Orleans to Shanghai, China for power generation (kg CO_2-e/MWh).

GHGs in the GHG Studies were reported on the common mass basis of kilograms (kg) of carbon dioxide equivalent using the global warming potential (GWP) of each GHG from the 2013 Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5). The 100-yr GWP was the timeframe used for comparison in this EA.

Segments related to natural gas production and processing and to regasification and end use would be the same for the exports proposed in the Application as in the GHG Studies. The three segments might have variation between these exports and the GHG Studies – these are shown in red in Table 4. Differences could result from 1) distance and conditions of pipeline transport from U.S. producing basins to the Manzanillo Plant's location as compared to the U.S. Gulf Coast; 2) conditions of operation for an LNG plant in Mexico versus a U.S. Gulf Coast facility; and 3) distance and conditions of LNG tanker transport from Gato to Shanghai, as compared to tanker transport from New Orleans to Shanghai.

Therefore, differences in calculated emissions between Gato Dos and the GHG Studies model would primarily result from: 1) any difference in natural gas pipeline transport distance between U.S. producing basins and the liquefaction plants and differences in emissions between Mexican pipelines and U.S. pipelines; 2) differences in the emissions associated with liquefaction in Mexico versus the U.S.; and 3) the difference in nautical distance traveled by an LNG tanker between liquefaction plants and Shanghai, China. Each of these categories is examined below.

Pipeline Transport – In the GHG Studies, extracted and processed natural gas is transported via pipeline, where GHG emissions are associated with: 1) the combustion of a portion of the natural gas in compressors; 2) intentional venting; and 3) fugitive losses of natural gas. Emissions from these sources are a function of the length of the transport distance, the number of compressor stations (a function of the length of transport), and the associated natural gas storage capacity (a function of the throughput), as well as maintenance and operational practices. It is reasonable to assume that throughput is comparable in both scenarios, in which case the potential differences are reduced to the possible difference in pipeline transport distance from gas sources to the Manzanillo Plant, and to possible emissions differences between pipeline operations in Mexico and in the United States.

Possible Differences in Pipeline Transport Distance

Analysis in the GHG Studies estimated that the average pipeline transport distance from natural gas extraction to an LNG terminal on the U.S. Gulf Coast was 971 kilometers (km) (about 600 miles), that being the average pipeline transmission distance for LNG exports from the United States.[101] This distance is based on the characteristics of the entire transmission network and the delivery rate for natural gas in the United States. The pipeline transport distance from U.S. production sources to the proposed Manzanillo Plant could be longer. For example,

[101] Nat'l Energy Tech. Lab., *Life Cycle Analysis of Natural Gas Extraction and Power Generation* (DOE/NETL-2019/2039), at 4 (Apr. 19, 2019), https://www.netl.doe.gov/energy-analysis/details?id=3198.

the distance from the Permian Basin producing area, a likely source of gas for Gato Dos, to Manzanillo, Mexico, is conservatively estimated at 850 miles.[102] This represents an approximately 42% increase in average transportation distance from the 600-mile estimate of pipeline transportation mileage used in the GHG Studies.

The GHG studies estimated that total expected life cycle GHG emissions of U.S. LNG exports to Shanghai, China from the Gulf Coast would be 688 kg CO2-e/MWh (See Exhibit A-2 in the 2019 Update). The GHG studies estimated that 8.7%, or 60 kg CO2-e/MWh, of these emissions would be from pipeline transport.[103] Applying a proportionate relationship between distance and emissions - - based upon extending the transportation distance from 600 miles to 850 miles (a 42% increase) - - would increase the pipeline transport contribution to GHG emissions from 60 kg CO2-e/MWh to 85 kg CO2-e/MWh (also a 42% increase), with emissions rates from pipeline transportation held constant at levels estimated for U.S. pipelines in the GHG Studies.[104] This would increase total estimated life cycle emissions to approximately 713 kg CO2- e/MWh, an increase of about 3.6%.[105]

For this EA, Gato Dos estimates that pipeline emissions in Mexico would be the same as from pipelines located in the United States. This is the same assumption DOE made in the GHG Studies for pipeline emissions in all countries. The pipelines listed above in Mexico were generally constructed following the mid-1990s. The Tarahumara Gas Pipeline commenced service in 2013.[106]

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102 The Waha Hub is near the hamlet of Coyanosa, Texas, in the Permian Basin. It is approximately 850 miles from Manzanillo, Colima, Mexico.

103 Using the 100-year GWP.

104 In the GHG Studies, emissions profiles of transmission pipelines in other countries are held constant at the U.S. rate, with the pipeline transport distance being the determinant of emissions differences (2019 Update, Exhibit 5-5, at 13).

105 An increase of 25 kg CO2-e/MWh from a total of 688 CO2-e/MWh: 25/688 = about 3.6%.

106 https://bcysa.mx/en/pf/Tarahumara-pipeline/.

However, even presuming a higher and growing divergence in emissions rates between Mexican and United States pipeline transportation as a result of possible policy and regulatory differences with the U.S. regulatory system does not produce a materially different conclusion. These include EPA requirements to report greenhouse gas emissions for pipeline transportation[107] (and other components of the natural gas supply chain) and FERC requirements for accounting for lost and unaccounted for gas.[108] U.S. pipeline operators are subject to regulatory emission limits,[109] with those pipelines that do not meet regulatory limits subject to a waste emissions charge established in the Inflation Reduction Act of 2022.[110]

At the same time, DOE notes that the average pipeline age in Mexico[111] is less than that of most U.S. pipelines, and therefore, on any given date existing Mexican pipelines may experience fewer age-related maintenance issues that could increase the risk of methane emissions.[112]

The extent to which the Mexican pipeline emissions rate would influence total life cycle emissions is limited, given that pipeline transportation emissions would be approximately 11.3%

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107 EPA's Greenhouse Gas Reporting Program (GHGRP) covers emissions from different areas of the oil and gas industry through several of its subparts. The reporting is required of domestic natural gas market participants in different phases of oil and natural gas value chains, including extraction, production, transport, and use. https://www.epa.gov/ghgreporting.

108 Pipelines subject to FERC's jurisdiction are required to disclose volumes of natural gas lost and unaccounted for during pipeline operations in FERC Form 2. https://www.ferc.gov/sites/default/files/2020-04/form-2.pdf.

109 *See* Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, 86 Fed. Reg. 63,110 (Nov. 15, 2021).

110 Inflation Reduction Act of 2022, Pub. L. 117-169, § 60113 (2022).

111 *See* EIA, Today in Energy, "U.S. natural gas exports to Mexico set to rise with completion of the Wahalajara system" (July 6, 2020) ("Since 2016, Mexico has been expanding its natural gas pipeline system, which has supported continual growth in U.S. natural gas exports."), https://www.eia.gov/todayinenergy/detail.php?id=44278. For the U.S., see PHMSA, Gas Transmission Miles By Decade Installed, https://portal.phmsa.dot.gov/analytics/saw.dll?Dashboard (retrieved Sept. 23, 2022). The data in the table indicate that 9% of the natural gas transmission miles of pipeline in the U.S. were installed since 2010. Construction on new pipeline capacity in the U.S. is increasingly contentious and challenging.

112 *See* PHMSA, Pipeline Replacement Background (Apr. 26, 2021), https://www.phmsa.dot.gov/data-and-statistics/pipeline- replacement/pipeline-replacement-background ("[F]ollowing major natural gas pipeline incidents, U.S. Department of Transportation and the Pipeline Hazardous Materials Safety Administration issued a Call to Action to accelerate the repair, rehabilitation, and replacement of the highest-risk pipeline infrastructure. Among other factors, pipeline age and material are significant risk indicators.").

of the total life cycle emissions for a delivery to Asia, based on the GHG Studies, with the longer pipeline transport distance described above.[113]

LNG Liquefaction – In the GHG Studies, LNG plant operations and associated emissions were based on the following:

- The LNG plant includes pre-treatment of the input pipeline-quality gas, liquefaction of the pre- treated gas, and on-site temporary storage of LNG before it is loaded onto an ocean tanker.
- The pre-treatment processes include: acid gas removal (removal of CO2 and H2S from the pipeline feed gas, to avoid freezing and plugging in downstream units); molecular sieve dehydration (removal of water to avoid freeze-up and unplanned shutdowns); and heavy hydrocarbon removal to protect the main heat exchanger from freezing and plugging, via adsorption or cryogenic distillation.
- The liquefaction plant employs an Optimized Mixed Refrigerant process in combination with a multi-stage process described below.
- Applicant estimates based on the Plant's anticipated capacities and ship capacity and frequency assumptions, that the residence time of LNG on site work be between 4 days and 9 days. During storage, boil-off gas (~0.02% to 0.1%) is assumed to be re-liquefied, or entered back into the supply-chain.
- Pre-treatment and liquefaction energy requirements are assumed to be met through combusting a stream of natural gas as it leaves the pre-treatment facility and before it enters the liquefaction facility, or electricity from local power generation facilities.

The Manzanillo Plant is engineered based upon Siemens SGT-750 turbines in simple cycle for the main refrigeration driver, which has an approximate efficiency of 40%. The turbine package is equipped from the manufacturer with a Dry Low Emission (DLE) combustion system.

The Optimized Mixed Refrigerant (OMR™) process integrated into the Manzanillo Plant uses a multi-stage, single refrigerant compressor/loop per train, multiple brazed aluminum heat exchangers inside insulated cold box modules. The use of a single mixed refrigerant loop per train minimizes both the number of seals that must be used as well as other potential leak/release

113 Pipeline emissions, including estimated increased emissions due to the longer transport distance, would comprise about 12.4% of total life cycle emissions for the 2019 Update's representative European destination.

points. This reduces points of wear in the process. In addition, each compressor is equipped with dual bidirectional dry gas seal(s).

Furthermore, the OMR™ process uses a refrigerant recovery vessel that allows changes to the refrigerant mixture. This allows the refrigerant compressor to stay at its most efficient points of operation through varying process and weather conditions that are to be expected over the life of the facility. An added benefit of this vessel is that it provides a place to store refrigerant during routine maintenance periods, thus eliminating the need to vent the refrigerant during these activities.

On a per-unit-volume-of-LNG-produced basis, GHG emissions from the proposed Gato Project and the Gulf Coast LNG plant modeled in the GHG Studies would be similar.

LNG Tanker Transport – As discussed above, the Application emphasizes exports to markets in Asia, although it does not limit its request to those markets. Because of the Application's emphasis, Applicant respectfully contends that the evaluation should focus on transport routes to Asia, although exports to other markets could occur. The 2019 Update based LNG tanker transport emissions on fuel combustion emissions (both compressed boil off gas and supplementary diesel fuel), average speed assumptions, and the distance between New Orleans and Shanghai via various sea routes. The calculation assumed that the shortest distance would be 18,544 km (via the Panama Canal), while the distance via other alternate routes would vary from 25,436 to 31,722 km. In comparison, the distance from Manzanillo, Mexico (the Plant's location) to Shanghai is about 16,185 km.

It is reasonable to assess marine transport-related GHG emissions as directly (*i.e.*, linearly) related to transport distance. Based on these calculations, the increase in GHG emissions associated with LNG tanker transport would be between 14.5% and 96% greater (relative to a Manzanillo terminal), depending on the New Orleans to Shanghai route chosen for comparison. As the share of the scenario's emissions contributed by LNG tanker transport is approximately 11% (*i*.e., [Maritime fuel component of total divided by total], this would translate to an increase in overall emissions of about 1.5% -10.5% due to the longer tanker travel route. LNG exports to some other markets, such as Europe, would entail greater shipping distances than the ones analyzed in the GHG Studies for those markets, and commensurately greater GHG emissions from marine transport of LNG.

ii. No Action Alternative

If Gato Dos was not authorized, other LNG production capacity could be constructed in the United States or another country to serve some or all of the LNG demand Gato Dos is intended to serve. Since it is uncertain where this production would take place, it is not possible for DOE to make a quantitative comparison of estimated life cycle GHG emissions. The differences described could result in additional GHG emissions associated with Mexican LNG exports, as compared to alternative LNG sources and/or changes in natural gas production and consumption. However, it is reasonable to conclude that GHG emissions would be broadly similar, and, given the global nature of climate change, would have similar incremental impacts. Some operations, however, in countries where production is not subject to as rigorous emissions oversight as in the U.S., may result in greater emissions.

C. DOE/FE Should Not Impose Point-of-Export or Future Construction Restrictions

1. Volume and Facility Point-of-Export Restrictions Are Unnecessary

Given the existence of abundant physical cross-border pipeline capacity to export U.S. gas to the Project, the authorizations sought in this Application should not experience restrictions upon the points of export and/or facilities along the U.S./Mexican border that Gato Dos may utilize to export gas destined for the Project. If, in the future, the Project or any other additional capacity is proposed at the Project requiring an aggregate amount of exported U.S. gas in excess of the volumes for which Gato Dos is requesting authorization in this Application, appropriate applications will be filed with the DOE/FE for any authorizations necessary with respect to those incremental volumes. However, a requirement to obtain additional DOE/FE approval before exporting natural gas in amounts authorized by the order requested in this Application from specific existing or future cross-border facilities is unnecessary and would be inconsistent with the DOE/FE's treatment of other natural gas export applications.

Gato Dos respectfully requests that DOE/FE issue an order without any restriction tied to future upstream and/or cross-border developments, consistent with the way DOE/FE has usually treated exports from U.S. LNG facilities.[114] Several pipeline facilities have been approved and/or constructed to interconnect directly LNG terminals for non-FTA export authorizations, and the DOE/FE has not required any of the relevant authorization holders to obtain additional authorization from the DOE/FE prior to utilizing new pipeline capacity.[115]

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[114] This application does not involve "unusual circumstances" discussed in Order No. 3768, where an applicant proposed to export volumes that exceeded the capacity of the single pipeline essential to completing the transportation central to the re-export proposal. *See* DOE/FE Order No. 3768 at 195-197; *see* also Bear Head Order at 157. Here the physical capacity of the border-crossing facilities identified at pp. 7-8, *supra* to this Application substantially exceeds the export volumes requested in this Application. Typically, authorized volumes have been tied to liquefication capacity of the relevant LNG terminal downstream of transportation pipelines. *See, e.g., Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 3792 (approving LNG export volumes incremental to previously-authorized volumes in order to align authorized volumes to the maximum liquefaction production capacity of the liquefaction facilities); *Cameron LNG, LLC,* DOE/FE Order No. 3797, FE Docket No. 15-67-NG, *Final Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Cameron Terminal Located in Cameron and Calcasieu Parishes, Louisiana to Non- Free Trade Agreement Nations* (Mar. 18, 2016) (authorizing LNG export volumes incremental to previously authorized volumes to match the peak capacity of the relevant liquefaction trains under optimal conditions); *Lake Charles LNG Export Company, LLC*, DOE/FE Order No. 4010, FE Docket No. 16-109-LNG, Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel from the Lake Charles Terminal in Lake Charles, Louisiana, to Free Trade Agreement and Non-Free Trade Agreement Nations (June 29, 2017) (authorizing additional export volumes to align volumes authorized for export with the project's liquefaction production capacity).

[115] *See, e.g.*, *Transcontinental Gas Pipe Line Co., LLC*, 153 FERC ¶ 61,077 (2015) (approving Transco's Gulf Trace Expansion Project, which would provide transportation of up to 1,200,000 Dth/d of incremental firm transportation service from Transco's existing facilities at St. Helena Parish, Louisiana, to the Sabine Pass

VII. APPENDICES

The following attachments and Appendices are included with this Application:

Appendix A:	Verification
Appendix B:	Opinion of Counsel
Appendix C:	Map of Pipeline Facilities
Appendix D	Location of Facility – Filed Under Seal
Appendix E:	Enhanced Efficiency
Appendix F:	Consumption Effects
Appendix G:	Relative Emissions
Appendix H:	Relevant Pipelines in Mexico
Appendix I:	Additional Circumstances Associated with Gato Negro Permitium Dos, S.A.P.I. de C.V. Project
Appendix J:	E.I.A. U.S. Natural Gas Supply Disposition and Prices Table 13
Appendix K	Excerpts from the latest Lazard report
Appendix L	NREL 2023 Study, excerpt
Appendix M	Memorandum (LBNL-44698 (12/9/99) memo to Skip Laitier, EPA Office of Atmospheric Programs, from Jonathan Koomey, *et al.*)
Appendix N	Solar Learning Center document
Appendix O	NYSERDA web page
Appendix P	October 27, 2021 letter from D. Whitehead, Director of Environmental Permits, NY State Dept. of Environmental Conservation to Ms. Brenda Colella.

LNG terminal in Cameron Parish, as well as Sabine Pass's proposal to construct piping and valves at its Section 3 liquefaction terminal to receive the gas from Transco's project); *Cheniere Creole Trail Pipeline, L.P.*, 142 FERC ¶ 61,137 (2013) (original feed gas pipeline for Sabine Pass); *Columbia Gulf Transmission, LLC*, 152 FERC ¶ 61,214 (2015) (approving Columbia Gulf Transmission's Cameron Access Project, which would provide transportation of up to 800,000 Dth/d of incremental firm transportation service from new and looped facilities in Jefferson Davis, Cameron, and Calcasieu Parishes, Louisiana); *Tennessee Gas Pipeline Co., L.L.C.*, 161 FERC ¶ 61,265 (2017) (approving Tennessee's Lone Star Project to provide up to 300,000 Dth/d of firm transportation service to a new interconnection with the Corpus Christi LNG terminal on Tennessee's 100 Line in San Patricio County, Texas).

Appendix Q	CLIMATEWIRE: "Michigan sets 2040 deadline to get all power from clean energy" [Climate Wire 11/29/23]; "Mich. City offers new model for 100% clean power" [EEnews 11/15/21]
Appendix R	"Colorado is on track to nearly zero out power emissions – report" [Energy Wire 11/2/23]
Appendix S	Citizen's Utility Board Analysis of CEJA
Appendix T	Spectrum News 10/13/21 (HB 951); "North Carolina has a new clean energy law. Here's what's in it"
Appendix U	Megawatt Daily, 11/21/23, p. 4

VIII. CONCLUSION

For the reasons set forth above, Applicant respectfully requests that the DOE/FE issue an order authorizing Gato Dos, for a term extending through December 31, 2050, on its own behalf and as agent for others to: (1) export .647 Bcf/d of natural gas by pipeline to Mexico; (2) re-export the equivalent of .556 Bcf/d as LNG from the Project to non-FTA countries; and (3) use up to the difference (*e.g.*, .091 Bcf/d) in the transportation and liquefaction process in Mexico, an FTA country, as described herein. Gato Dos further requests that the date for the commencement of authorization coincide with the date of first export. Gato Dos requests issuance of such authorization no later than February 21, 2025.

Respectfully submitted,

/s/ Mark F. Sundback
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ATTORNEY FOR GATO NEGRO PERMITIUM DOS, S.A.P. I de C.V.

August 21, 2024

APPENDIX A
(Verification)

State of TEXAS)
)
County of HARRIS)

I, Steve Magness, being first duly sworn, hereby affirm that: as Gato Negro Permitium Dos, S.A.P. I. de C.V.'s manager. I am authorized to execute this verification on behalf of Gato Negro Permitium Dos, S.A.P. I. de C.V.; I have read the foregoing Application and am familiar with the contents thereof; and that all allegations of fact therein contained are true and correct to the best of my knowledge, information and belief.

Name
Title: Manager

Subscribed and sworn to before me
This 20TH of AUGUST, 2024

Notary Public

MATTHEW A COHEN
Notary ID #134830129
My Commission Expires
March 28, 2028

NOTARY PUBLIC STATE OF TEXAS

My Commission Expires:

MARCH 28, 2028

APPENDIX B

Opinion of Counsel

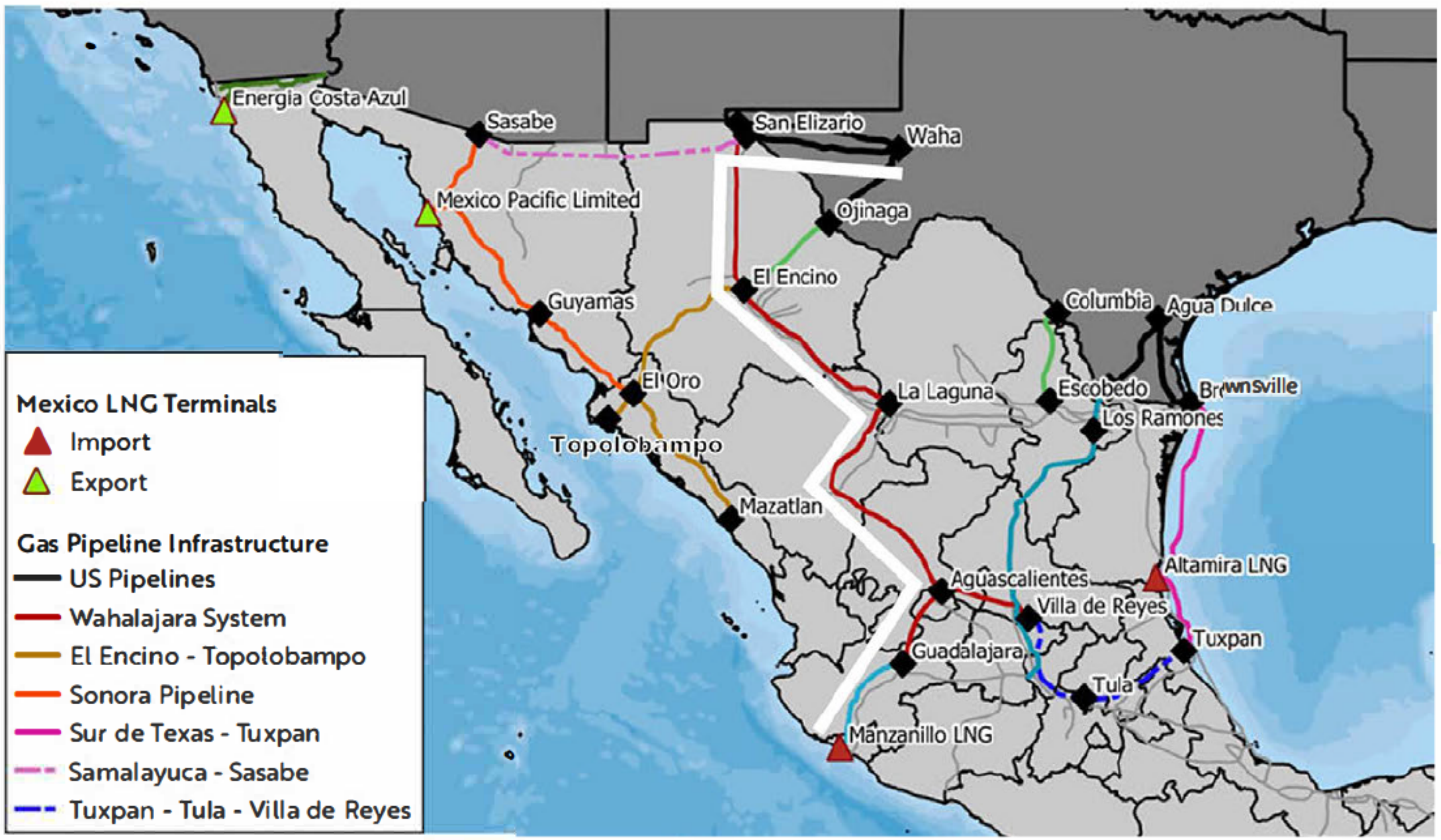
This opinion is submitted pursuant to Section 590.202(c) of the Department of Energy administrative procedures. The undersigned is counsel to Gato Negro Permitium Dos, S.A.P. I. de C.V. for this purpose.

I have reviewed the corporate documents and it is my opinion that the proposed import/export of natural gas is/are within the company's corporate powers.

Emilio Paulon Fuentes
Legal Counsel

SMRH:4872-3621-8575.5

APPENDIX C
Map of Pipeline Facilities



Note: Map only contains a subset of current and pending pipelines

APPENDIX D
Location of Facility

Materials Filed Under Seal

Appendix E
Enhanced Efficiency

Appendix E

More modern data show decreasing environmental impacts. A report issued at the end of 2023 indicated the methane intensity of Permian natural gas drillers hit a record low despite record high levels of production, aided by the use of satellite data. Midland-Reporter-Telegram (Midland Tx.), "Texas Methane Emissions Just 0.12% in 2022, a Record Low." Melia McEwen (12/14/23). A copy of that article is appended hereto.

By providing additional markets for the burgeoning natural gas output, venting and flaring in production fields will be reduced. In the past, venting and flaring has been identified as a source of significant concern.

> "In Texas, growing crude oil production from the Permian Basin . . . has contributed to a rapid increase in natural gas flaring." ["Natural gas venting and flaring in North Dakota and Texas Increased in 2019," EIA *Today In Energy* (12/8/20)].

The creation of additional markets for disposition of U.S. natural gas disposal will reduce the volume of unwanted associated natural gas that otherwise would be flared or, if the flaring is extinguished, simply vented into the air (*see* 2019 NETL Update at p. 8).

Unconventional natural gas production may be involved in Applicant's sales, but the incremental environmental impacts that would result from LNG exports to non-FTA nations are not reasonably foreseeable and cannot be analyzed with any particularity. The aggregate quantity of natural gas that ultimately may be exported to non-FTA countries is uncertain. *See* Order No. 3768 at pp. 204-205. As DOE explained in *Sabine Pass*, Order No. 2961-A, without knowing where, in what quantity, and under what circumstances additional gas production will arise, the environmental impacts resulting from production activity induced by LNG exports to non-FTA countries are not "reasonably foreseeable" within the meaning of the CEQ's NEPA regulations.[1]

[1] *Sabine Pass*, DOE/FE Order No. 2961-A, at 11 (quoting 40 C.F.R. § 1508.7).

DOE determined in Order No. 3768 (*see* pp. 206 *et seq*) that environmental concerns should be directly addressed through federal, state, or local regulation, for instance by environmental regulators or through self-imposed industry guidelines where appropriate – rather than by prohibiting exports of natural gas. As noted in the instant Application, EPA has taken steps in December 2023 to regulate natural gas well emissions. *See* 40 C.F.R. Section 60.8 (2024). Additionally, also as noted elsewhere in these materials, BLM has issued a final rule that dissuades gas venting, flaring and leaks from production on federal and tribal lands.[2]

Efficiency of the current Project is enhanced by the use of Optimized Mixed Refrigerant technology, which achieves refrigeration goals while minimizing compression power necessary to achieve them. *See* pages attached hereto from the manufacturer's website, and Application pp. 50-51.

[2] *See* "Waste Prevention, Production Subject to Royalties, and Resource Conservation", RIN 1004-AE79 Final Rule (89 Fed. Reg. 25378) 4/10/24, 43 C.F.R. §§ 3162.3-1, 3179.

RESILIENCE

Texas’ Methane Emissions Just 0.12% in 2022, a Record Low

A new report found that the state’s methane output last year continued its decadelong downward trend, confirming that Permian Basin oil and natural gas producers are successfully lowering emissions.

Dec. 14, 2023 •

Mella McEwen, Midland Reporter-Telegram, TNS

A new report indicates Texas' Permian Basin oil and natural gas producers are succeeding in driving methane emissions lower even as oil and natural gas output rises to record highs.

Texans for Natural Gas, an educational campaign of the Texas Independent Producers and Royalty Owners Association, released its new report indicating Texas producers drove methane intensity to a record low 0.12 percent in 2022 even as output reached record levels. The report emphasized the decade-long downward trend in methane intensity.

The report comes a week after the US Environmental Protection Agency issued its final regulations covering methane emissions.

Ed Longanecker, TIPRO president and spokesperson for Texans for Natural Gas, told the *Reporter-*

Telegram by email, "According to a recent study, the new methane rules will directly impact hundreds of thousands of low producing wells in the United States and could have a notable impact on future oil and gas production volumes. We are currently reviewing the language and coordinating with our members and partner trade associations across the country. I also suspect there will be legal challenges to this rulemaking, so we will need to wait and see how it ultimately plays out."

Since the rules are expected to directly impact hundreds of thousands of low-producing wells, TIPRO is engaged in a variety of initiatives to specifically help smaller operators, according to Longanecker. He wrote key elements of those initiatives include providing educational resources and training on methane detection and mitigation techniques, developing a collaborative program to provide affordable Leak Detection and Repair services and routine maintenance, access to funding programs for equipment upgrades and repairs that prevent or reduce methane leakage. Efforts also include guidance on revised emissions reporting through the Environmental Protection Agency Greenhouse Gas Reporting Program (GHGRP) and how this affects producers.

Authors of the study noted the US oil and natural gas industry has invested more than $300 billion in technologies to mitigate greenhouse gas emissions over the past two decades.

"Effective solutions exist, but some are cost prohibitive for certain operators. We are working on a collaborative effort to create some economy of scale for producers in the Permian Basin to access and utilize satellite technology to reduce emissions in partnership with a company called Satelytics," Longanecker wrote.

The consortium would allow more companies to collaboratively monitor overlapping assets of oil and gas and pipeline infrastructure using satellite data analyzed by AI-based analytics that yield actionable alerts, far superior to other providers. This type of innovation and collaboration will continue to expand and positively impact emission reduction efforts beyond the notable and quantifiable success our industry has already achieved, as noted in our new report, he continued.

In addition to Satelytics, Permian Basin operators are utilizing drones to access difficult-to-reach areas, and fixed cameras and sensors to enable around-the-clock surveillance. Through organizations like The Environmental Partnership and Texas Methane and Flaring Coalition, operators continue to collaborate and share best practices to reduce emissions and remain leaders in sustainable energy production, the report added.

The Permian Basin's success in reaching some of the lowest methane intensity rates in the world exemplifies the region's commitment to environmental stewardship. We will continue to proactively work to minimize oil and gas development's environmental impact—all while producing affordable, abundant, and reliable energy," Longanecker concluded.

LIFE CYCLE GREENHOUSE GAS PERSPECTIVE ON EXPORTING LIQUEFIED NATURAL GAS FROM THE UNITED STATES: 2019 UPDATE

SELINA ROMAN-WHITE, SRIJANA RAI, JAMES LITTLEFIELD, GREGORY COONEY, TIMOTHY J. SKONE, P.E.

September 12, 2019

DOE/NETL-2019/2041

5 Key Modeling Parameters

The following sections detail the key modeling parameters used to model natural gas and coal. For a full report on the modeling of upstream natural gas, reference the *Life Cycle Analysis of Natural Gas Extraction and Power Generation* (NETL, 2019). For additional information on the modeling of downstream natural gas, reference **Appendix B**. For additional information on the modeling of coal, reference the multiple works cited in **Section 4** of this report.

5.1 Upstream Natural Gas

When the end use of natural gas is a power plant, there are four key steps in the supply chain:

- **Production:** A natural gas production site has a well pad that holds permanent equipment and provides room for development and maintenance activities. The construction of natural gas wells requires a well casing that provides strength to the well bore and prevents contamination of the geological formations that surround the gas reservoir. Well completions are the activities following well drilling and preceding production and, in the case of unconventional wells, involve the injection and flowback of water to stimulate production. Liquids unloading is an intermittent emission from wells that are affected by wellbore fluid accumulation. Other sources of emissions include the gas vented from pneumatically controlled devices and fugitive emissions from flanges, connectors, open-ended lines, and valves. When vapor recovery units are feasible, vented gas is captured and flared; otherwise, vented gas is released to the atmosphere. Production operations also include the combustion of natural gas by reciprocating engines that drive compressors, as well as combustion of natural gas and diesel to provide heat and energy for other supporting equipment.
- **Gathering and Boosting:** Natural gas gathering and boosting networks receive natural gas from multiple wells and transport it to processing or transmission facilities. Gathering and boosting sites include acid gas removal (AGR), dehydration, compressors operations, pneumatic devices and pumps.
- **Processing:** A natural gas processing facility removes impurities from natural gas, which improves its heating value and prepares it for pipeline transmission. Natural gas processing facilities include AGR, dehydration, hydrocarbon liquids removal, and compression operations. When feasible, vapor recovery units capture vented gas and send it to flares. The size and complexity of processing plants are variable; in some cases, processing occurs near production sites, while in other cases a central processing facility receives natural gas from gathering and boosting facilities.
- **Transmission Stations, Storage Facilities, and Transmission Pipelines:** A natural gas transmission system is a network of large pipelines that transport natural gas from processing facilities to the city gate (the point at which natural gas can be consumed by large-scale consumers or transferred to local distribution companies). A typical natural gas transmission pipeline is 32 inches in diameter and is constructed of carbon steel. Transmission pipelines operate at 1,500 pounds per square inch of gauge pressure (psig).

CRYOSYS THE PERFECT STORM OF EXPERTISE AND CAPABILITY

We are experts in LNG and Natural Gas Processing.

We have developed systems that combine advanced engineering whith the highest quality fabrication, allowing us to design, build and execute high performance gas processing solutions faster, more efficiently and more economically than has ever been posible.

We use Innovative, Efficent and Optimized Technology in LNG to provide complete solutions.

Why LNG?

LNG is a clean fossil fuel and a good alternative to reduce greenhouse gas emissions. Once gas is liquefied to LNG, it can b transported and regasified for different applications

How do we do it? With Our Propertary Design of “Optimized Mixed Refrigerant”

Contained in a **Cold Box Module Isolated** with perlite, which simplifies installation and **Optimizes the Performance.**

The Cold Box also serves as **Secondary Containment,** which acts as a backup in case of leak.

Our Technologies are **Designed and Built** not only for **Optimum Performance**, but also for an exceptional reliability and **Minimal Maintenance.**

LOCATION

Our Technologies are World Class and Well Tested.

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Appendix F
Consumption Effects

Appendix F

By displacing fuels and systems that emitted more carbon dioxide or methane, the re-purposing of natural gas would achieve society's aims with lower carbon emissions. Production sources using more expensive and inefficient carbon-emitting coal as a fuel could be displaced or the coal-fired electric-generation would have to be replaced to remain competitive. As noted in the instant Application, the 2019 GHC Report found that:

> [T]he use of U.S. LNG exports for power production in European and Asian markets will not increase GHG emissions from a life cycle perspective, when compared to regional coal extraction and consumption for power production. The results show that for all 100-yr time horizon scenarios the generation of power from natural gas has lower life cycle GHG emissions than power generation from regional coal. . . . [2019 NETL Update, p.32]

The 2019 NELT Update does not fully re-balance markets for demand and supply responses to price signals. Hence the 2019 NETL Update does not entirely account for the reduction in either the demand in the U.S. based on marginally higher prices (and thus the decline in GHG emissions) nor the benefit of U.S. LNG supplies crowding coal out of Asia energy markets at the margin by lowering LNG prices there. For instance, lignite—the dirtiest of coal products—is being mined in Indonesia for export and burning in power plants. Just one country alone exported $2 billion of lignite to China in 2022. *See* the attached material. Eliminating lignite and other coal consumption is the least challenging source of GHG reductions that the U.S. can manage overseas.

Assessments of life cycle environmental consequences also must take into account some practical realities of coal fired generation.[1] It takes hours to bring even hot coal-fired generators

---

1 *See* "Make Your Plant Ready For Cycling Operations," Steven Lefton and Douglas Hillerman (8/1/2011), www.powermag.com/print/issues/features, Table 1.

into synchronization with the grid, *and days* for cold coal-fired generators.[2] During that time, coal is being burned and emissions are occurring without putting power into the grid. Coal plants experience a range of inefficiencies as they ramp up (and ramp down), which tend to increase emissions. Moreover, efforts to use coal in conjunction with renewable generation are leading operators to attempt to cycle the coal fired generation more frequently, even for coal units originally built as baseload facilities. But increasing the use of coal units in readiness to ramp up and down requires keeping them running at levels of output (*e.g.*, 20-60% of capacity) that reflect lower levels of efficiency, and by virtue of remaining on stand-by throughout the day, creating emissions even when running on stand-by. In contrast, natural gas fired peakers do not need to run for hours before they can be deployed to follow load. They are much more readily activated and dispatched, and do not need to be maintained in continuous operation to provide the flexibility that operators would otherwise have to run coal plants to achieve. Retrofitting coal plants to achieve greater peaking flexibility will create more sunk costs on the single greatest source of emissions in the electric generation industry, potentially prolonging coal-fired generation's service lives. A significant number of coal plants in the U.S. were retired before their previously anticipated retirement dates because low cost natural gas made retrofitting the coal plants hopelessly uneconomic. That strategy can be applied across a wider region.

The problems of overseas carbon emissions may get worse without U.S. natural gas, as indicated by a 2023 report:

> Coal power plant permitting, construction starts and new project announcements accelerated dramatically in China in 2022, with new permits reaching the highest level since 2015. The coal power capacity starting construction in China was six times as large as that in all of the rest of the world combined. [CREA, Center for Research on Energy and Clean Air, Briefing, Feb. 27, 2023]

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2 *Id.*

That report stated that

> Throughout 2022, China granted permits for 106 gigawatts of capacity across 82 sites, quadruple the capacity approved in 2021 and equal to starting two large coal power plants each week, said the report. [CNN, "China approved equivalent of two new coal plants a week, report finds" CNN, Jessie Yeung Feb. 27, 2023]

According to NPR:

> "[h]igh prices for liquified natural gas due to the war in Ukraine also led at least one province to turn to coal," one observer noted. "China is building six times more new coal plants than other countries, report finds" [(3/2/23) by Julia Simon].
>
> China quadrupled the amount of new coal power approvals in 2022 compared to 2021." [*Id*].

The CNN article, entitled "China approved equivalent of two new coal plants a week in 2022, report finds" (2/27/23 (attached hereto)) noted:

> . . . hundreds of brand-new coal power plants will make meeting China's climate commitments more complicated and costly. [*Id*. p. 3]

China's new coal plants are not economic according to that report;

> Power generation companies are not keen to build new coal-fired power plants because coal-fired power generation is significantly lossmaking at current coal and power prices.
>
> * * * *
>
> [T]he slogan "build first and reform later", [was] used by the central-level [National Development and Reform Commission] in September 2022. . . . In practice the slogan means accelerating the construction of new, large coal power plants.
>
> * * * *
>
> Of China's six regional grids, the South and East grid are the only ones that don't suffer from a clear thermal power overcapacity problem. Yet, 50% of newly announced projects and 40% of construction starts took place in the grids with overcapacity.
>
> * * * *

> Environmental Impact Assessments of these projects foresee them operating for 4500–5500 hours per year, which is above the average for baseload coal power plants in China. [*Id.* at pp. 6-7, 13, 2, 14 (footnotes omitted)]

Reuters related "warnings that the world's biggest economy is likely to end up . . . with even more loss-making power assets. . . . . 'China has more coal power capacity than it needs' said [an analyst] . . . . China's National Development and Reform Commission (NRDC) has . . . flagged that at least 200 MW of coal capacity is expected to be deployed." [*See* "China's new coal plants set to become a costly second fiddle to renewables," Reuters, 3/22/2023 at pp. 2, 4, attached hereto].

Coal accounted for 58.4% of China's total power generation last year, but high prices have meant many plants have suffered losses for years. More than half of the country's large coal power firms were loss-making in the first half of 2022, according to the China Electricity Council.

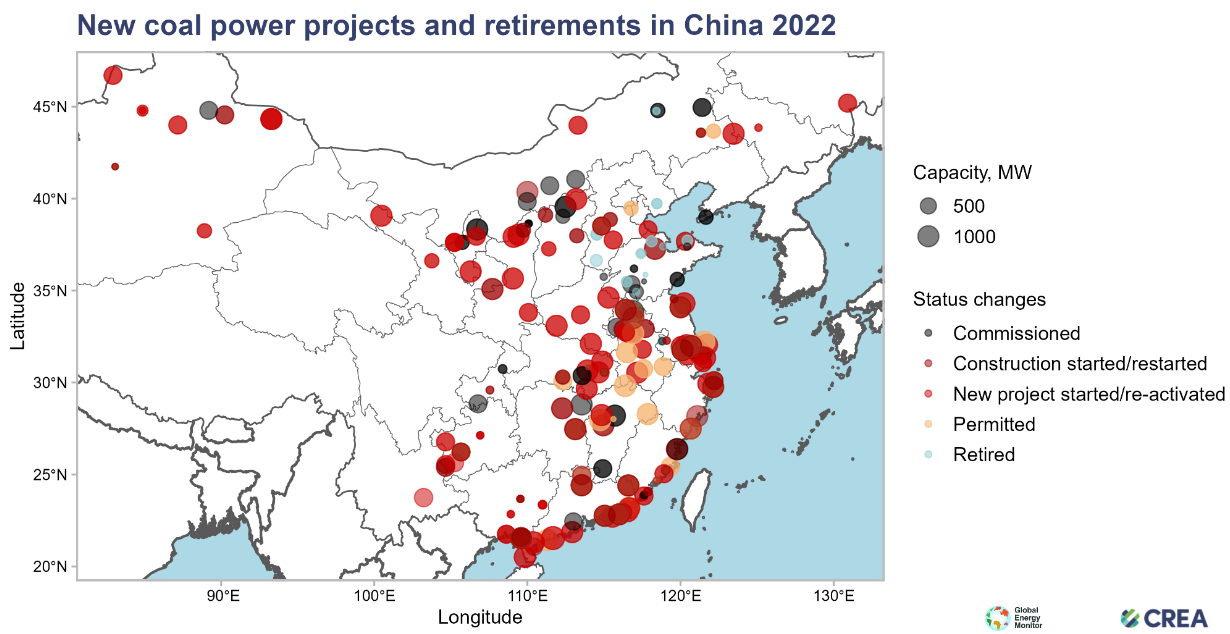
* * * *

> "I think the expectation of . . . capacity payments [recommended on Chinese grids] is one motivation for coal power groups to pursue new projects despite the fact that power generation from coal is unprofitable at the moment," said Lauri Myllyvirta, lead analyst at CREA.
>
> Instead of building expensive new plants, China could instead encourage existing plants with surplus capacity to deliver electricity to regions that need it the most, said Matt Gray, chief executive of think tank TransitionZero.
>
> "It would be far cheaper... to incentivise provincial trading than incentivising new loss-making coal," he said.

See "China's new coal plants to become a costly second fiddle to renewables," Reuters, David Stanway and Muyu Xu (3/22/23).

Briefing, February 2023

China permits two new coal power plants per week in 2022



Key findings

- Coal power plant permitting, construction starts and new project announcements accelerated dramatically in China in 2022, with new permits reaching the highest level since 2015. The coal power capacity starting construction in China was six times as large as that in all of the rest of the world combined.
- 50 GW of coal power capacity started construction in China in 2022, a more than 50% increase from 2021. Many of these projects had their permits fast-tracked and moved to construction in a matter of months. A total of 106 GW of new coal power projects were permitted, the equivalent of two large coal power plants per week[1]. The amount of capacity permitted more than quadrupled from 23 GW in 2021. Of the projects permitted in 2022, 60 GW were not under construction in January 2023, but are likely to start construction soon, indicating even more construction starts in 2023. In total, 86 GW of new coal power projects were initiated, more than doubling from 40 GW in 2021.
- The largest amount of capacity moved ahead in Guangdong, Jiangsu, Anhui, Zhejiang and Hubei.
- New coal power capacity added to the grid kept steady from 26.2 GW in 2021 to 26.8 GW in 2022. These two years had the lowest annual additions since 2003, reflecting the lower level of construction starts around 2017–2020. Capacity additions will rebound in a few years when projects that broke ground last year begin to come online.
- China has seen a rapid increase in electric peak loads in 2021–2022, with the highest recorded momentary load increasing by 230 GW, due to an increase in the prevalence of air conditioners and exceptionally intense heat waves. This is prompting an increase in coal power plant development as a costly and sub-optimal solution, especially in major electricity demand centres and provinces neighboring them.
- Of China's six regional grids, the South and East grid are the only ones that don't suffer from a clear thermal power overcapacity problem. Yet, 50% of newly announced projects and 40% of construction starts took place in the grids with overcapacity.
- The provinces permitting a large amount of new coal power plants try to justify the projects as "supporting" power capacity to ensure grid stability and the integration of renewable energy. This justification doesn't hold water, however, as the plants

[1] The size of coal-fired power generating units varies widely; the actual number of permitted units was 168 at 82 different plant sites.

are intended to run at baseload utilization, and these specific provinces are laggards in growing clean energy generation to meet their demand growth.

- Avoiding the need for more coal-fired power plants requires improvements in energy efficiency, demand response and investments in storage, as well as improving grid operation.
- Plant retirements slowed down further in 2022, with 4.1 GW of coal-fired capacity closed down in 2022, compared with 5.2 GW in 2021. Policies on closing down small and inefficient plants have been revised to keep these plants online instead as back-up or in normal operation after retrofits.

What are the implications for CO_2 emissions?

The massive additions of new coal-fired capacity don't necessarily mean that coal use or CO_2 emissions from the power sector will increase in China. Provided that growth in non-fossil power generation from wind, solar and nuclear continues to accelerate, and electricity demand growth stabilizes or slows down, power generation from coal could peak and decline. President Xi has also pledged that China would reduce coal consumption in the 2026–30 period. This would mean a declining utilization rate of China's vast coal power plant fleet, rather than continued growth in coal-fired power generation.

Even then, hundreds of brand-new coal power plants will make meeting China's climate commitments more complicated and costly. The politically influential owners of the plants have an interest in protecting their assets and avoiding a rapid build-out of clean energy and a phase-out of coal.

While China is making rapid progress in scaling up clean energy, the country's power system remains dependent on coal power capacity for meeting electricity peak loads and managing the variability of demand and clean power supply. The continued addition of new coal power capacity implies insufficient emphasis on overcoming the power system and power market constraints that perpetuate dependence on coal.

The worst-case scenario is that the pressure to make use of the newly built coal power plants and prevent a steep fall in utilization leads to a moderation in China's clean energy buildout, and/or the promotion of energy-intensive industries to consume the electricity. This could mean a major increase in China's CO_2 emissions over this decade, undermining the global climate effort, and could even put China's climate commitments in danger.

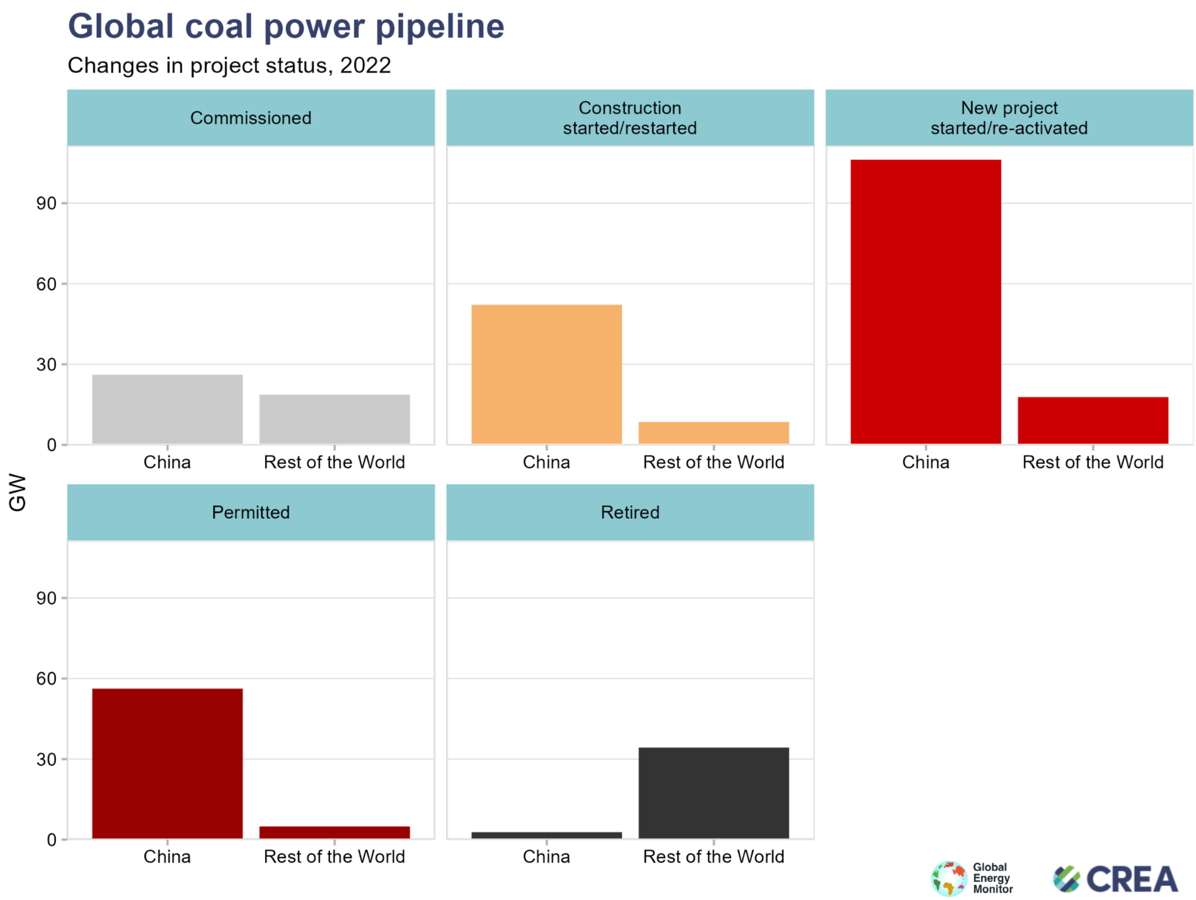


Figure 1: China dominates new coal power project activity, while retiring little existing capacity. Coal power projects in China and the rest of the world with changes in project status in 2022 (between Global Coal Plant Tracker January 2022 and January 2023 updates). Categories are mutually exclusive — e.g. plants that both obtained permits and started construction in 2022 are only included in "construction started".

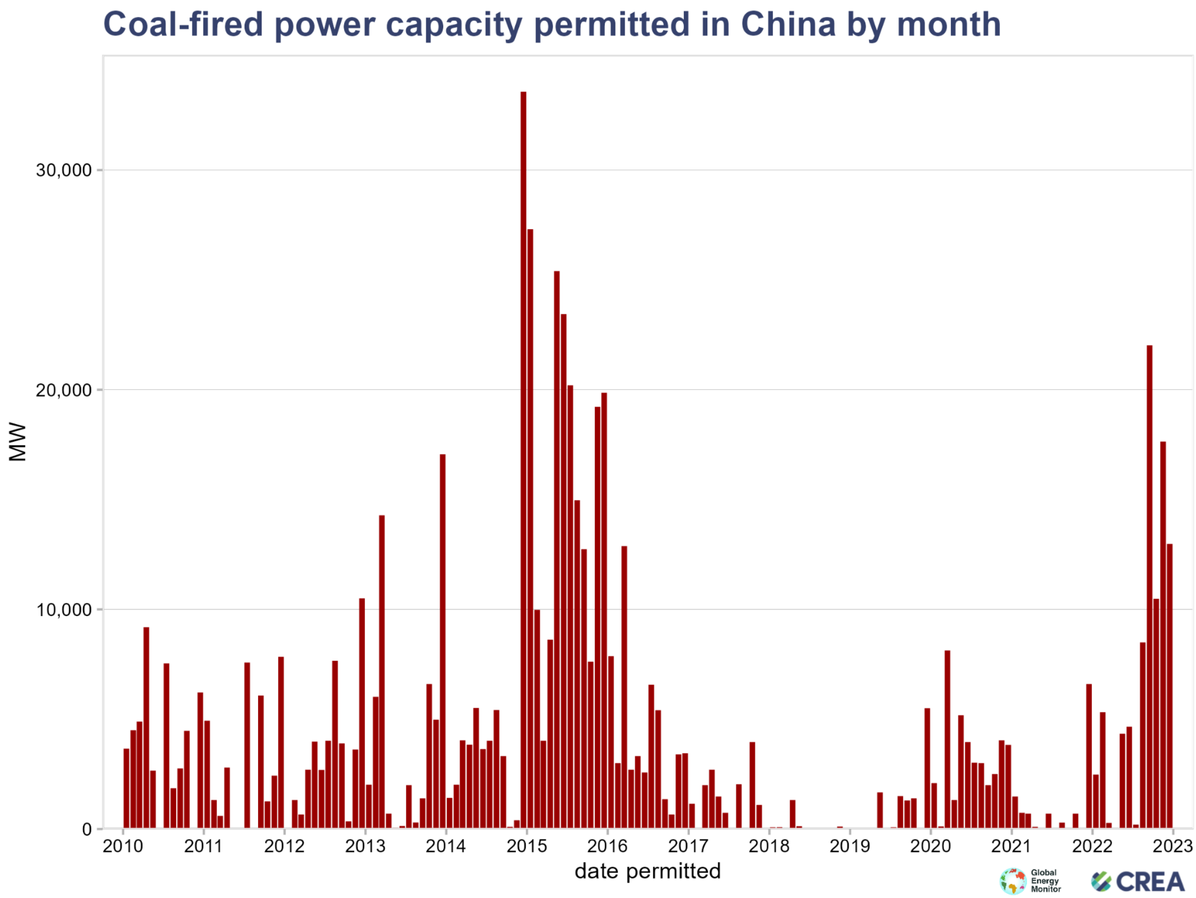


Figure 2: The second half of 2022 saw a steep acceleration in the permitting of new coal power plants, only eclipsed by the 2015 surge that happened after provincial governments gained the authority to permit new projects. The 2015 surge was followed by a clampdown on overcapacity.

Coal power projects accelerated in the second half of 2022

Coal power plant permitting, construction starts and new project announcements accelerated dramatically in China in 2022, with new permits reaching the highest level since 2015. The coal power capacity starting construction in China was six times as large as that in all of the rest of the world combined.

50 GW of coal power capacity started construction in China in 2022, a more than 50% increase from 2021, with many projects newly permitted in 2022 and fast-tracked to construction. A total of 106 GW of new coal power projects were permitted, more than quadrupling from 23 GW in 2021. Of the projects permitted in 2022, 60 GW were not under construction in January but are likely to start construction soon, indicating even more construction starts in 2023. In total, 86 GW of new coal power projects were initiated, more than doubling from 40 GW in 2021.

The speed at which projects progressed through permitting to construction in 2022 was extraordinary, with many projects not even mentioned in provincial five-year plans issued in early 2022 or otherwise announced sprouting up, gaining permits, obtaining financing and breaking ground apparently in a matter of months. A Huadian executive boasted of obtaining permits to build a 4000 MW coal power plant in a matter of 63 days after taking ownership of the project.

New coal power capacity added to the grid kept steady from 26.2 GW in 2021 to 26.8 GW in 2022. The two years had the lowest annual additions since 2003, reflecting the lower level of construction starts around 2017–2020. Capacity additions will rebound in a few years when projects that broke ground last year begin to come online.

China has not seen such a wave of new permits for new coal-fired power plants since the permitting frenzy of 2015, when provincial governments were given the authority to approve new projects. Furthermore, in that instance, a flood of new permits was not in line with central government policy, particularly the emphasis on reducing overcapacity, and a clampdown followed soon after. Currently, the central government appears to be supportive of the new projects, however, with the energy regulator targeting 165 GW of coal power construction starts in 2022–23.

Power generation companies are not keen to build new coal-fired power plants because coal-fired power generation is significantly lossmaking at current coal and power prices. However, as both the central and provincial governments are encouraging or ordering the start of new projects, and ensuring that financing is available, power companies are opting to build uneconomic plants rather than give up market share to competitors.

The acceleration stands out even more in the case of newly announced projects, where the volume of new proposals was at the highest level by far since the start of GEM's historical dataset in 2014.

Retirements continued at low levels, with the policy calling for "outdated" coal power plants scheduled for retirement to be converted into backup plants instead, or even retrofitted to meet new standards. Inner Mongolia's government work plan for 2023 goes even further, speaking of "converting", or more accurately, re-branding, conventional coal power plants into "new green smart power plants".

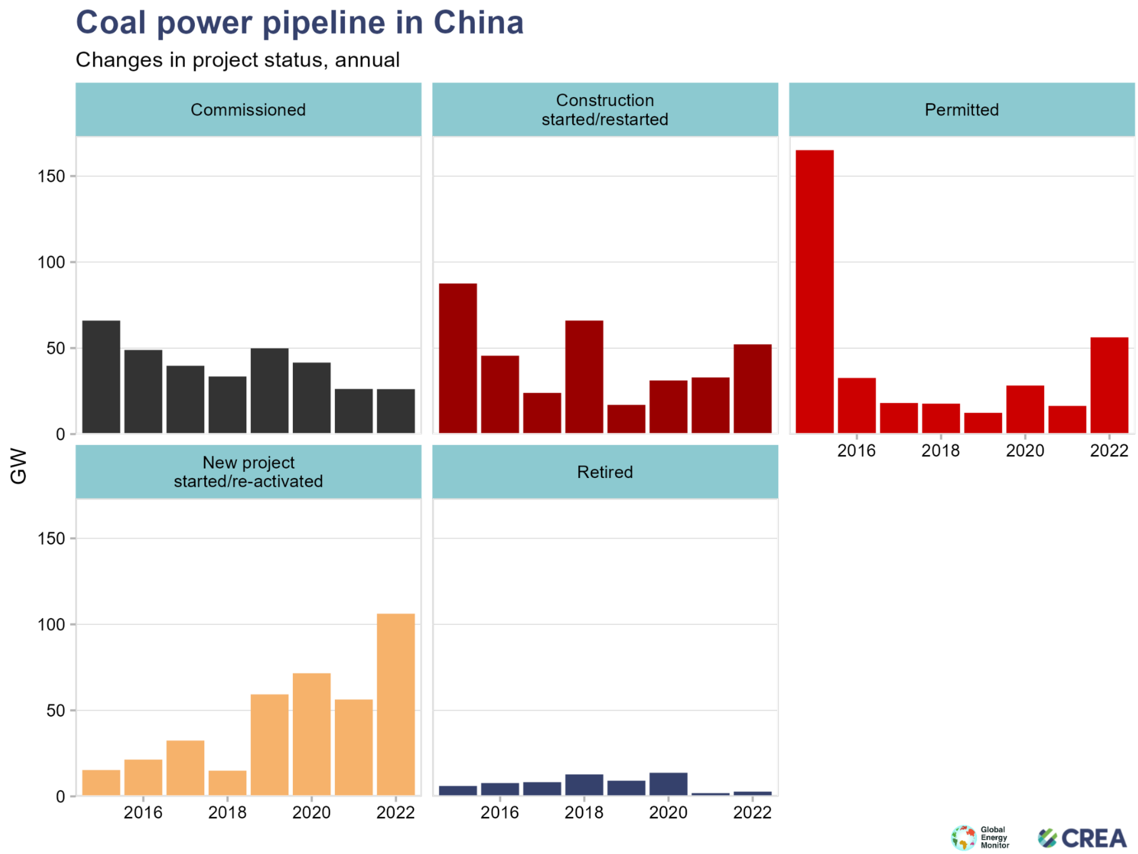


Figure 3: New project activity accelerated dramatically in 2022. Changes in coal power project status by year (between the Global Coal Plant Tracker January updates). Categories are mutually exclusive — e.g. plants that both obtained permits and started construction in 2022 are only included in "construction started".

Record clean energy additions, but more needed to cover demand growth

In terms of absolute increases in non-fossil power generation, China made new records in 2021–22. The acceleration was particularly impressive looking at non-fossil energy excluding hydropower, which had unfavorable operating conditions during most years, meaning no increase in generation despite capacity additions.

A record 125 GW solar and wind capacity was added in China in 2022, breaking the previous record from 2020. Of the added capacity, 87 GW was solar and 38 GW wind. The added generation equals 2% of China's electricity demand, meaning that added wind and solar power covered half of the demand growth of 3.6%. The amount of wind capacity connected to the grid in fact came in significantly under the forecasts of 55–70 GW for the year, as the Covid-19 epidemic and control policies affected grid connections.

Clean energy growth is bound to accelerate, with 165 GW of new wind and solar capacity targeted for 2023, and bidding for new wind turbine supply contracts alone reaching 100 GW in 2022. As electricity demand growth is likely to accelerate, even this increase won't be sufficient to supply all of the demand growth without increasing power generation from fossil fuels.

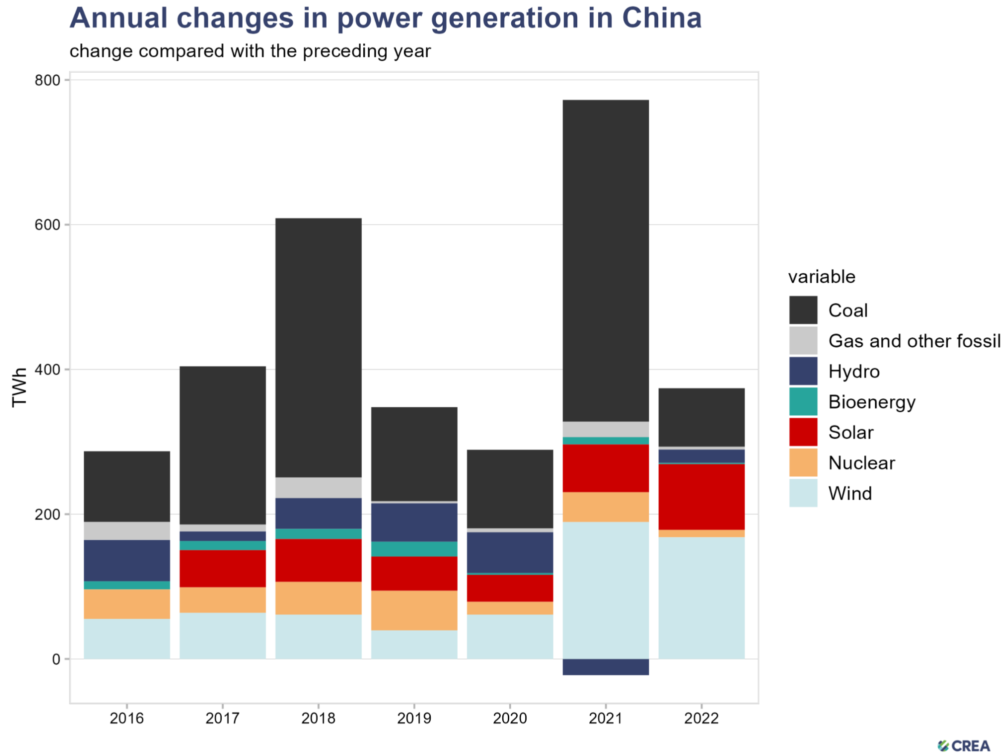


Figure 4: Clean energy is catching up to power demand growth. Source: CREA analysis of Ember [Monthly electricity data](#).

Rapid increase in peak loads challenges the power system paradigm

China has seen a rapid increase in electric peak loads in 2021–2022, with the highest recorded momentary load reaching 1290 GW in 2022, an increase of 230 GW from 2020. This was due to an increase in the prevalence of air conditioners and exceptionally intense heat waves. The increase in peak loads is prompting an increase in coal power plant development as a costly and sub-optimal solution, especially in major electricity demand centres and provinces neighboring them.

The increase in electricity demand for cooling in summer 2022 was extreme, not only because of the record-high temperatures but also because summertime highs in temperatures had been below trend in the previous two years. Air conditioning had become much more prevalent since 2019 which was the previous year that saw a week with above-average temperatures. A trend towards hotter maximum temperatures during the summer is apparent in the data spanning 2010–22, but the increase from 2020–21 represented fluctuation around this much more gradual trend.

The challenge of meeting demand peaks is exacerbated by China's rigid grid operation paradigm. Most provinces are building thermal power capacity to match their local peak loads, without making use of the electricity transmission network. For example, during the drought in 2022, Sichuan continued to export large amounts of electricity to the east, while rationing consumption within the province. The lack of flexible grid management perpetuates reliance on coal power and creates a perceived need to build more of it.

However, as the growth in electricity demand continues, avoiding the need for more coal-fired power plants will require improvements in energy efficiency, demand response and investments in storage, as well as improving grid operation.

Building coal-fired power plants to cover peak loads means low utilization of capital-intensive assets, making it an expensive way to solve the problem even in the absence of climate targets. In addition, China's carbon neutrality commitment means that the lifetime of new coal power plants will be very limited, further driving up the costs.

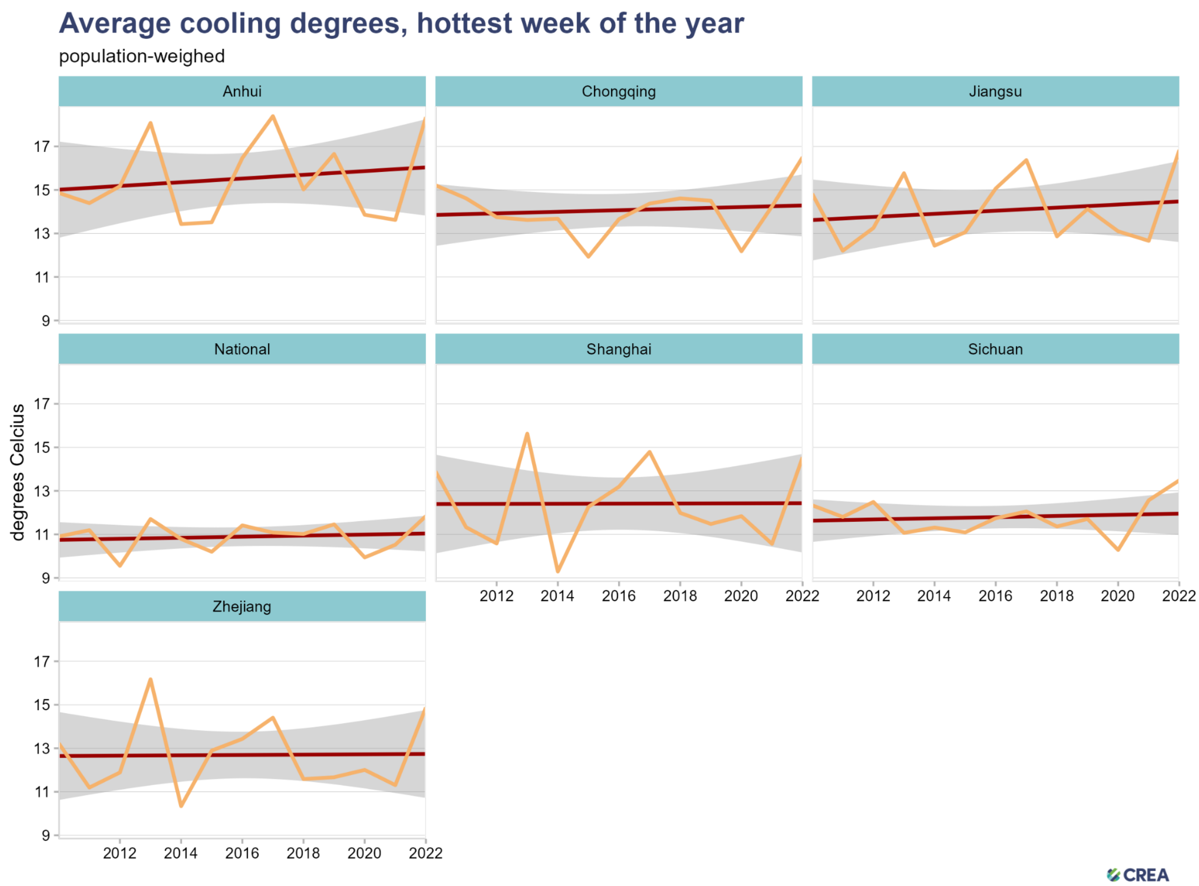


Figure 5: The 2022 heatwave caused record-high cooling needs in many affected provinces. Cooling-degrees are degrees above 24°C. Source: CREA analysis; gridded daily average temperatures are taken from the NCEP [Climate Forecast System](#) and population-weighted averages are calculated using the [Gridded Population of the World](#) from CIESIN.

“Coal power by any other name”: province energy policies

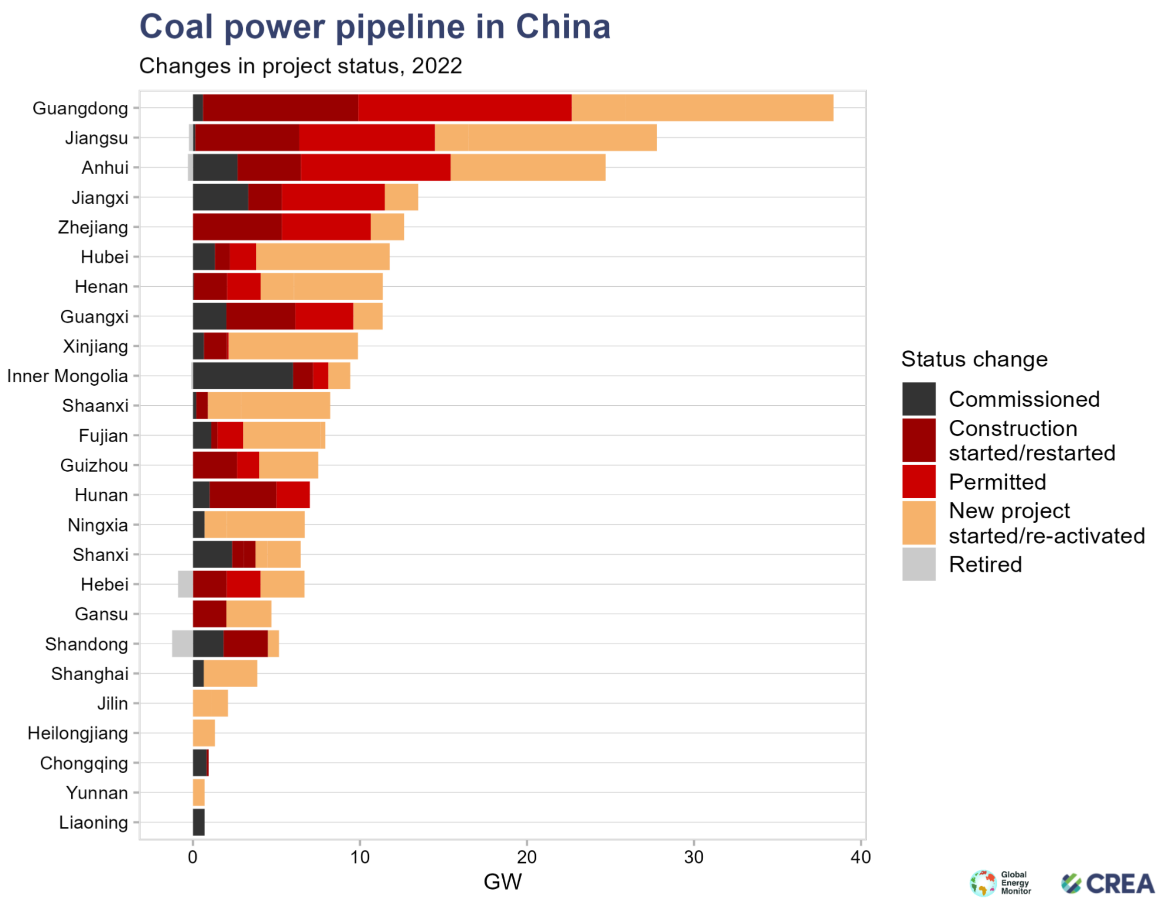


Figure 6: Changes in status of coal power plants and projects in 2022.

The largest amount of capacity moved ahead in Guangdong, Jiangsu, Anhui, Zhejiang and Hubei. Guangdong, Jiangsu and Zhejiang had the largest number of construction starts. Most permits were handed out in Guangdong, Anhui and Jiangsu.

Project activity slowed down in Inner Mongolia and didn’t see much acceleration in the other western provinces, showing that the current surge is driven predominantly by concern about capacity adequacy in the major demand centres.

The new coal power spree in Guangdong happened incredibly fast. None of the 10 new megaprojects approved in Guangdong in the second half of 2022 were included in the province's five-year plan on energy, issued in March 2022. The likely triggers for the scramble for new coal were the drought in the hydropower region of southwestern China in summer 2022, which affected power supply to Guangdong, as well as the record-high LNG prices. Guangdong has the most gas-fired power capacity among Chinese provinces and was therefore more vulnerable to the gas price shock.

Both the hurried process and the round number of exactly 10 new projects indicate that there was little consideration of the precise need or the alternatives for new coal. Paradoxically, the Guangdong provincial government's 2023 work plan rationalizes the province's coal power plant building spree with the headwinds faced by the economy, including weakening demand outlook and expectations. This reflects the logic of using large investment projects to stimulate the economy rather than an assessment based on supply and demand of power. The government work plan indicates that the province is seeking Beijing approval for a total of 23 GW of new "supporting" power capacity, meaning coal- and possibly gas-fired power.

The new wave of coal power projects in Jiangsu and Anhui appears to have been triggered by the drought and heatwave in summer 2022. During the drought, hydropower-rich Sichuan was experiencing an electricity shortage, but continued exporting its hydropower to the East China grid, the regional grid that covers both Jiangsu and Anhui. This triggered a scramble for additional generating capacity both at the receiving end, perhaps due to concerns that electricity imports from Sichuan might not be available during future droughts. In both Jiangsu and Anhui, new projects started moving ahead very fast after the summer.

Jiangsu's energy policy for 2023 is framed around the slogan "build first and reform later", used by the central-level NDRC in September 2022. This evolved from "build first and dismantle later", a slogan used by the State Council in summer 2021 in response to emission reduction plans proposed by provinces and industrial sectors that were deemed overly ambitious. Replacing "dismantling" with "reform" further emphasizes the gradual pace of targeted progress also in the longer term. In practice the slogan means accelerating the construction of new, large coal power plants.

Jiangsu's provincial government proposed a batch of three "supporting" coal power projects in September 2022, each with a capacity of 2x1,000MW. An even larger batch of 13 plant units with a total capacity of 11.3 GW was introduced in January 2023.

The new wave of coal power projects in Anhui followed the same pattern as in Jiangsu. Of the 10 coal power projects permitted in 2022, 9 were permitted or opened to public review before the permit in the second half of the year. Anhui, like Guangdong, chose the round number of ten large coal power projects to pursue, conveying more political symbolism than careful planning.

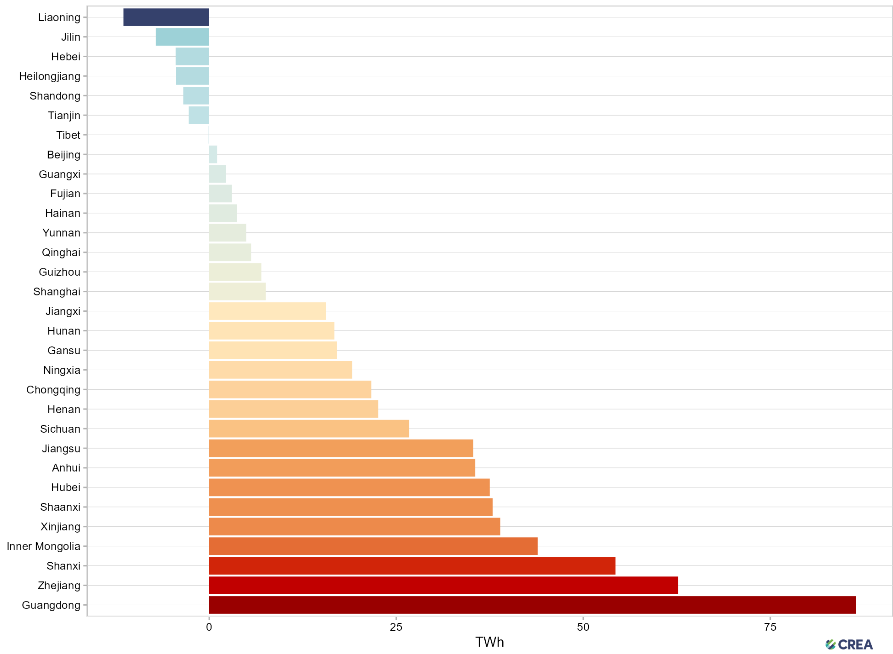
After the summer's power shortage, Sichuan, China's main gas-producing province, permitted seven gas-fired power projects with a total capacity of 8750 MW. The province is now also considering new coal-fired power projects as a part of its power grid and generation plan for 2022–25.

The new coal power plants in Guangdong, Jiangsu and Anhui are branded "supporting" generation sources, which is a reference to either "supporting grid stability" or "supporting intermittent renewables", as opposed to bulk power generation. This is because the National Energy Administration released a policy in February 2022 that said no new coal power plants would be approved for the purpose of bulk power generation. Designation as "supporting power sources" should imply low operating rates, as supporting sources should only run when there is a shortfall of capacity. However, the Environmental Impact Assessments of these projects foresee them operating for 4500–5500 hours per year[2], which is above the average for baseload coal power plants in China and in direct contradiction with labeling the plants as "supporting power sources".

The growth in non-fossil power generation in the provinces with the largest coal power investments don't justify the claim that coal power plants are acting as "supporting" sources. Guangdong and Zhejiang were the top two provinces increasing power generation from thermal power (mainly coal) in the past two years. In both provinces, as well as in Anhui and Hubei, over 75% of growth in total power generation came from thermal power. Jiangsu did somewhat better, getting more than half of total power generation growth from non-fossil sources, mainly wind and nuclear, but still had a major increase in thermal power generation. This shows that all of these provinces are still rapidly increasing bulk power generation from coal.

[2] See e.g. the EIAs for Huaneng Taicang 2x1000MW project (5000 hours/year) and Guoxin Shazhou 2x1000MW project (5000 hours/year) in Jiangsu; as well as Huaneng Haimen 2x1000MW project (4500 hours/year), Guangdong Yudean Huilai 2x1000MW project (5000 hours/year), Guangdong Yudean Bohe 2x1000MW project (5500 hours/year), and Guangdong Lufeng Jiahuwan 2x1000MW project (5500 hours/year) projects in Guangdong.

Changes in thermal power generation by province from 2020 to 2022



Shares of power generation sources in growth from 2020 to 2022

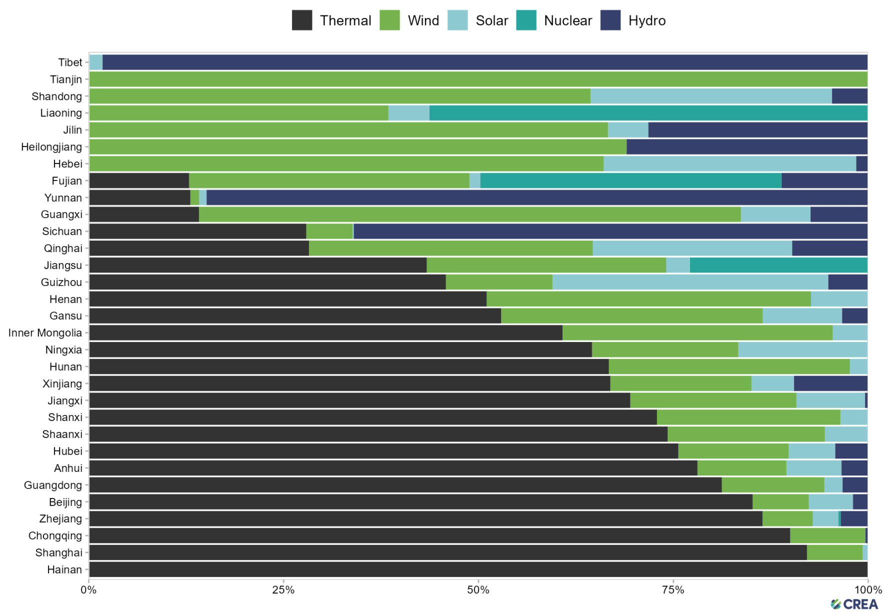


Figure 7. Sources of growth in power generation from 2020 to 2022 by province. Out of the five provinces adding most new coal power capacity, only Jiangsu has significant growth in clean power generation, but even there, almost half of the growth in power generation came from thermal power. In Guangdong, Zhejiang, Anhui and Hubei, the share was 75% or more. This implies that the provinces are still increasing bulk power generation from coal, and making little to no progress in moving coal to a "supporting" role despite their claims to the contrary.

Among the provinces that have not seen an increase in thermal power generation, and relatively little new coal project activity, Shandong plans to begin construction of 6 ultra-supercritical coal power projects in 2023, roughly 4 to 6 GW. However, GEM's data only includes one 2 GW permitted project for the province which hasn't entered construction, and 1.55 GW of additional proposed capacity. If this plan is implemented, there might be 5 more projects being permitted and entering construction in 2023.

Policy recommendations

- Strictly control new coal power capacity and reject or revoke permits to projects that are not necessary for "supporting grid stability" or "supporting the integration of variable renewable energy".
- Accelerate investment in clean power generation to fully meet growth in electricity demand and stop increasing bulk power generation from coal. Decarbonisation requires substantial changes in network infrastructure, market mechanisms, regulatory framework, and planning processes, which require central government facilitation.
- Increase investment in electricity storage, flexibility and transmission within grid regions. Create a level playing field for different storage, demand response and generation technologies for meeting peak demand, and enable clean flexibility technologies to scale up. While many technologies, such as pumped hydro, lithium-ion battery and demand-side technologies, are as mature as coal power and ready for wider adoption, current power systems and policy frameworks still lead developers to default to coal.
- Strengthen energy efficiency requirements for A/C units and for new buildings, and introduce a program of large-scale energy efficiency improvements for existing buildings.

About the data

The changes in coal power project status analyzed for this briefing are based on the latest January 2023 update of Global Energy Monitor's Global Coal Plant Tracker (GCPT), with complementary data on retirements, including for units below 30 MW, compiled from the provincial Development and Reform Commission and National Development and Reform Commission in China. The GCPT is an online database that identifies and maps every known coal-fired generating unit and every new unit proposed since January 1, 2010 (30 MW and larger). The tracker uses footnoted wiki pages to document each plant and is updated biannually. GCPT is the most detailed dataset available on the global coal power fleet, and has provided biannual updates on coal-fired generating capacity since 2015.

About Global Energy Monitor

Global Energy Monitor (GEM) develops and shares information on energy projects in support of the worldwide movement for clean energy. By studying the evolving international energy landscape, and creating databases, reports, and interactive tools that enhance understanding, GEM seeks to build an open guide to the world's energy system.

www.globalenergymonitor.org

About Centre for Research on Energy and Clean Air (CREA)

CREA is an independent research organisation focused on revealing the trends, causes, and health impacts, as well as the solutions to air pollution. We use scientific data, research and evidence to support the efforts of governments, companies and campaigning organisations worldwide in their efforts to move towards clean energy and clean air.

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LIFE CYCLE GREENHOUSE GAS PERSPECTIVE ON EXPORTING LIQUEFIED NATURAL GAS FROM THE UNITED STATES: 2019 UPDATE

SELINA ROMAN-WHITE, SRIJANA RAI, JAMES LITTLEFIELD, GREGORY COONEY, TIMOTHY J. SKONE, P.E.

September 12, 2019

DOE/NETL-2019/2041

Disclaimer

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TABLE OF CONTENTS

LIST OF EXHIBITS

ACRONYMS AND ABBREVIATIONS

AGR	Acid gas removal
AR5	Fifth assessment report
AU	Australia
BOG	Boil-off gas
BOR	Boil-off rate
Btu	British thermal unit
C3MR	Propane pre-cooled mixed refrigerant
CH_4	Methane
CN	China
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
DOE	Department of Energy
DZ	Algeria
ECF	Energy conversion facility
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EU	End use
GHG	Greenhouse gas
GHGI	Inventory of U.S. greenhouse gas emissions and sinks
GHGRP	Greenhouse Gas Reporting Program
GWP	Global warming potential
H_2S	Hydrogen sulfide
HHC	Heavy hydrocarbon removal
HRSG	Heat recovery steam generator
I-6	Illinois No. 6
IPCC	Intergovernmental Panel on Climate Change
kg	Kilogram
kJ	Kilojoule
kW	Kilowatt
km	Kilometer
kWh	Kilowatt hour
lb	Pound
LC	Life cycle
LCA	Life cycle analysis
LNG	Liquefied natural gas
m^3	Cubic meter
Mcf	Thousand cubic feet
MESA	Mission Execution and Strategic Analysis
MJ	Megajoule
MPa	Megapascal
MWh	Megawatt-hour
N_2O	Nitrous oxide
NETL	National Energy Technology Laboratory
NG	Natural gas
NL	Netherlands
ORV	Open rack vaporization
ppmv	Parts per million volume
PRB	Powder River Basin
psig	Pounds per square inch of gauge pressure
PT	Product transport
RMA	Raw material acquisition
RMT	Raw material transport
RU	Russia
scf	Standard cubic foot
SF_6	Sulfur hexafluoride
T&D	Transport and distribution
Tcf	Trillion cubic feet
U.S.	United States
ULSD	Ultra low sulfur diesel
UP	Unit process
yr	Year

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1 INTRODUCTION

This analysis calculates the life cycle greenhouse gas (GHG) emissions from imported natural gas and regional coal power in Europe and Asia. The primary research questions are as follows:

- How does exported liquefied natural gas (LNG) from the United States (U.S.) compare with regional coal (or other LNG sources) for electric power generation in European and Asian markets from a life cycle GHG perspective?
- How do those results compare with natural gas from Russia that is delivered via pipeline to the same European and Asian markets?

The National Energy Technology Laboratory (NETL) employed its characterization of an upstream natural gas production life cycle analysis (LCA) model to represent unconventional natural gas production and transportation to a Gulf Coast (New Orleans) liquefaction facility (NETL, 2019). An updated LCA model of the remaining LNG supply chain was used to represent the liquefaction, transport, and regasification of LNG exported to terminals in Rotterdam, Netherlands (European market representation) and Shanghai, China (Asian market representation). LNG from Oran, Algeria was modeled to represent an alternative regional source of LNG for European markets. LNG from Darwin, Australia was modeled to represent an alternative regional source of LNG for Asian markets. Conventional natural gas extracted from the Yamal region of Siberia in Russia was modeled as the regional pipeline gas alternative for both European and Asian markets. Regional coal production and consumption (e.g., Germany and China) was also modeled. Scenarios were handled using a parametric model that accounted for variability in supply chain characteristics and power plant efficiencies.

This analysis is based on data developed to represent U.S. natural gas production and LNG export and European/Asian import. The NETL natural gas and coal LCA models were adapted to represent the upstream portions of this study (NETL, 2010b; NETL, 2010c; NETL, 2012; NETL, 2019). U.S. natural gas production and average U.S. coal production were modeled as representative of foreign natural gas and coal production. No ocean transport of coal was included to represent the most conservative coal profile (regionally sourced or imported). The specific LNG export/import locations used in this study were chosen to represent an estimate for a region. The specific locations were required to allow for the estimation of LNG transport distances and do not imply the likelihood that LNG export or import will occur from that exact location. The same assumptions hold true for the Russian natural gas cases.

This analysis is an update of the 2014 LNG report (NETL, 2014b). Some aspects of the analysis structure remained the same, though the following updates were made to the prior analysis:

- Incorporation of the updated NETL characterization of upstream natural gas production (NETL, 2019)
- Updated unit processes for liquefaction, ocean transport, and regasification characterization
- Updated 100-year global warming potential for methane to reflect current IPCC, AR5 100-year time period

2 LCA APPROACH

This analysis is a cradle-to-grave LCA that begins with extraction of natural gas or coal and ends with electricity delivered to the consumer. NETL uses five life cycle (LC) stages, beginning with the acquisition of raw materials and ending with energy consumption. These five life cycle stages are listed below:

- **LC Stage 1:** Raw Material Acquisition (RMA) includes extraction of a natural resource and any necessary processing steps that prepare it for transport. The raw materials of this analysis are natural gas and coal.
- **LC Stage 2:** Raw Material Transport (RMT) includes the transport of a raw material between the extraction site and power plant. Natural gas is transported by pipeline and ocean tanker for the LNG cases and pipeline only for the Russian natural gas cases; coal is transported by rail.
- **LC Stage 3:** Energy Conversion Facility (ECF) includes the operation of a power plant that converts fuel to energy. The power plants of this analysis convert natural gas or coal to electricity. The handling and disposal of coal waste products are outside of the boundary of this analysis and are assumed to have minimal GHG emissions relative to the other processes considered in this analysis.
- **LC Stage 4:** Product Transport (PT) moves the product from the ECF to the consumer. In this analysis, electricity is transported over a national electricity grid.
- **LC Stage 5:** End Use (EU) represents the final consumption of a product. This stage serves to anchor the supply chain to the functional unit of 1 MWh of electricity. For the purpose of this study, this stage has no emissions associated with it.

Four scenarios are modeled in this analysis for two different geographies (Europe and Asia)[1]:

- **Scenario 1:** Natural gas is extracted in the United States from Appalachian Shale, transported by pipeline to an LNG facility where it is compressed and loaded onto an LNG tanker, transported to an LNG port in the receiving country (Rotterdam for Europe, Shanghai for Asia) where it is regasified, and then transported to a natural gas power plant. It was assumed that the power plant is located near the LNG import site.
- **Scenario 2:** Same supply chain as Scenario 1, but the source of natural gas is regional relative to the destination (Algeria for Europe, Australia for Asia). It was assumed that the regional gas is produced using conventional extraction methods. The LNG tanker transport distance is adjusted accordingly.
- **Scenario 3:** Natural gas is produced in the Siberian region of Russia utilizing conventional extraction methods and is transported by pipeline to a power plant in Europe or Asia.
- **Scenario 4:** Coal is extracted in the region of study (Europe or Asia) and transported by rail to a domestic coal-fired power plant in China or Germany. This analysis models both

[1] The goal of this analysis is to model plausible (medium and long-distance) export scenarios while also considering regional fuel alternatives. The purpose of the medium and long-distance scenarios is to establish low and high bounds for likely results.

surface sub-bituminous and underground bituminous coals based on U.S. extraction data.

In all four scenarios, electricity is delivered to end users via existing electricity transmission and distribution infrastructure. The functional unit, which serves as a basis for comparison, is 1 megawatt-hour (MWh) of electricity delivered to a consumer. The results of this analysis include only GHG emissions. GHGs in this inventory are reported on the common mass basis of carbon dioxide equivalents (CO_2e) using the global warming potentials (GWPs) of each gas from the 2013 Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5) (IPCC, 2013)[2]. The 100-yr GWP is the default timeframe used, though some exhibits display the 20-year timeframe as well. **Exhibit 2-1** shows the GWPs used for the GHGs inventoried in this study (IPCC, 2013).

Exhibit 2-1. IPCC AR5 GWPs

GHG	AR5 (IPCC, 2013)	
	20-yr	100-yr (Default)
CO_2	1	1
CH_4	87	36
N_2O	268	298
SF_6	17,500	23,500

[2] Table 8.7 in IPCC AR5 gives the GWPs on a 20 and 100-year time frame that includes climate-carbon feedback, but in the case of methane it does not include CO_2 from methane oxidation and mentions that values for fossil methane are higher by 1 and 2 for 20 and 100-year metrics respectively, hence the values of 87 and 36 are used in this report.

3 NATURAL GAS MODELING APPROACH

NETL's natural gas model uses a comprehensive set of parameters within a flexible network of unit processes, allowing the modeling of different sources of natural gas. Key variables include lifetime well production rates, emission factors for episodic emissions (e.g., completions and workovers), flaring rates at extraction and processing, workover and liquid unloading frequency, and pipeline distance. The model is run with 30 scenarios, including 27 onshore scenarios that span 14 production basins. Five types of extraction technologies are considered: conventional, coalbed methane, shale, tight, and associated gas. For additional details on the natural gas model, refer to the *Life Cycle Analysis of Natural Gas Extraction and Power Generation* (NETL, 2019). For Scenario 1 of this analysis, natural gas is modeled as unconventional gas from the Appalachian Shale (one of the 30 upstream natural gas scenarios found in the NETL 2019 work). For the purposes of this analysis, Appalachian Shale gas was used as a proxy for new unconventional natural gas production. Additionally, U.S. onshore conventional gas serves as a proxy for the regional LNG supply options (Algeria for Europe and Australia for Asia) and extraction in Siberia for pipeline transport to the demand centers. U.S. onshore conventional gas is represented by a U.S. conventional production-weighted average of the 9 upstream conventional scenarios (out of the 30 total upstream scenarios found in the NETL 2019 work).

In all three natural gas scenarios for this analysis, the extracted and processed natural gas is transported via pipeline, either to an LNG terminal (Scenario 1 and Scenario 2) or directly to a power plant (Scenario 3). The transmission of natural gas by pipeline involves the combustion of a portion of the natural gas in compressors, intentional venting, and fugitive losses of natural gas. For Scenario 1 and Scenario 2, the pipeline distance from natural gas extraction site to the LNG terminal is 971 km. This is the average distance of natural gas pipeline transmission in the United States (NETL, 2019). This distance is based on the characteristics of the entire transmission network and delivery rate for natural gas in the United States. Note, the same pipeline distance is used for both the U.S. and regional LNG scenarios. This simplification was used to focus on the differences in life cycle GHG emissions from transport of the LNG.

NETL's model captures the LNG supply chain in the following manner: after extraction and processing, natural gas is transported by pipeline to a liquefaction facility. The LNG is then liquified and loaded onto an ocean tanker, transported to an LNG terminal with regasification operations, regasified and then fed to a pipeline that transports it to a power plant. The data for the LNG supply chain accounts for the construction and operation of LNG infrastructure (NETL, 2010a; NETL, 2013b; NETL, 2013c). For this analysis, it was assumed that the natural gas power plant in each of the import destinations is located close to the LNG port, so no additional pipeline transport of natural gas is modeled in the destination country. This analysis assumes the power plant is existing infrastructure and thus does not account for the construction impacts of building the power plant.

For the U.S. (New Orleans) export options, the Panama Canal is a viable option for all ship capacities (150,000 – 180,000 m^3) (IGU, 2017). All other routes are assumed to be able to accommodate these ship sizes as well. The distances used for LNG transport are available in **Section 5.**

For Scenario 3, the pipeline distance was calculated based on the great circle distance between the Yamal district of Siberia, Russia, to a power plant located in Rotterdam, Netherlands, or Shanghai, China. Yamal was chosen as the extraction site because that region accounted for 82.6 percent of Russian natural gas production in 2012 (EIA, 2013a; EIA, 2013b). The great circle distance is the shortest possible distance between two points on a sphere and was, therefore, used to represent the shortest possible pipeline distance between the extraction source and the power plant. An additional 1,000 km of pipeline transport was added to the great circle distance to adjust it to the expected pipeline transport distance. Given the extensive pipeline networks in Europe and Asia, determining an actual distance was not possible. This assumption is tested in the uncertainty analysis section of this analysis. The distances used for pipeline transport of Russian gas are available in **Section 5**.

The efficiency of the destination power plant is an important parameter required for determining the life cycle emissions for natural gas power. Average baseload natural gas-fired power plants in the United States have a net efficiency of 46.4 percent (NETL, 2019). This analysis uses the range of efficiencies that are consistent with the NETL modeling of natural gas power in the United States (NETL, 2019). This analysis assumed the same range of power plant efficiencies in the destination countries as was used for the U.S. model. The efficiency range is designed to be representative of fleet baseload power plants.

The transmission of electricity from the power plant to consumer incurs a 7 percent loss of electricity (NETL, 2013a). The consumption of electricity does not have any energy or material flows. A comprehensive list of the modeling parameters and values for the natural gas scenarios are provided in **Section 5**.

4 COAL MODELING APPROACH

This analysis uses NETL's existing LCA model for the extraction and transport of sub-bituminous and bituminous coal in the United States as a proxy for foreign extraction in Germany and China. Foreign coal production was modeled as having emissions characteristics equivalent to average U.S. coal production.

Raw material extraction for coal incorporates extraction profiles for coal derived from the Powder River Basin (PRB), where sub-bituminous, low-rank coal is extracted from thick coal seams (up to approximately 180 feet) via surface mines located in Montana and Wyoming, and coal derived from the Illinois No. 6 (I-6) coal seam, where bituminous coal is extracted via underground longwall and continuous mining. In general, PRB represents coal from surface mining sources, and I-6 coal represents coal from underground sources. The regionally extracted coal is transported to the power plant by rail in both the European and Asian cases. The expected rail distance for both locations is 725 miles, modeled with uncertainty bounds of 500 miles.

PRB coal is modeled using modern mining methods at the following mines: Peabody Energy's North Antelope-Rochelle mine (97.5 million short tons produced in 2008); Arch Coal, Inc.'s Black Thunder Mine (88.5 million short tons produced in 2008); Rio Tinto Energy America's Jacobs Ranch (42.1 million short tons produced in 2008); and Cordero Rojo Operation (40.0 million short tons produced in 2008). These four mines were the largest surface mines in the United States in 2008 according to the National Mining Association's 2008 Coal Producer Survey (NMA, 2009). For the purposes of this assessment, it is assumed that the coal seam in the area of active mining was previously drilled to extract methane. Based on the NETL *Quality Guidelines for Energy Systems Studies: Methane Emissions from Mining Powder River Basin Coals* and *Quality Guidelines for Energy Systems Studies: Detailed Coal Specifications*, this analysis uses a factor of 8 scf/ton for coal bed methane emissions for surface mining of PRB coal and a higher heating value of 8,564 Btu/lb (NETL, 2010b; NETL, 2012).

I-6 coal is part of the Herrin Coal seam and is a bituminous coal that is found in seams in the southern and eastern regions of Illinois and surrounding areas that typically range from about 2 to 15 feet in thickness. I-6 coal is commonly extracted via underground mining techniques, including continuous and longwall mining. I-6 coal seams may contain relatively high levels of mineral sediments or other materials, and, therefore, require coal cleaning (beneficiation) at the mine site. During the acquisition of I-6 coal, methane is released during both the underground coal extraction and the post-mining coal preparation activities. Based on the NETL *Quality Guidelines for Energy Systems Studies: Methane Emissions from Mining Illinois Basin Coals* and *Quality Guidelines for Energy Systems Studies: Detailed Coal Specifications*, this analysis uses a factor of 360 scf/ton for coal bed methane emissions for underground mining of I-6 coal and a higher heating value of 11,666 Btu/lb (NETL, 2010c; NETL, 2012).

The heating value of coal and the heat rate of the power plant were used to determine the feed rate of coal to the power plant. Average baseload coal-fired power plants in the United States have a net efficiency of 33.0 percent (NETL, 2014a). For consistency, this analysis utilized the range of efficiencies that were previously used for the modeling of coal power in the United

States (NETL, 2014a). This analysis assumed the same range of power plant efficiencies for Europe and Asia as the U.S. model. The efficiency range is designed to be representative of fleet baseload power plants.

Electricity transmission and consumption is modeled using the same data used by the natural gas power scenario. The transmission of electricity from the power plant to consumer incurs a 7 percent loss of electricity (NETL, 2013a). The consumption of electricity does not have any energy or material flows. A comprehensive list of the modeling parameters and values for the coal scenarios are provided in **Section 5**.

5 KEY MODELING PARAMETERS

The following sections detail the key modeling parameters used to model natural gas and coal. For a full report on the modeling of upstream natural gas, reference the *Life Cycle Analysis of Natural Gas Extraction and Power Generation* (NETL, 2019). For additional information on the modeling of downstream natural gas, reference **Appendix B**. For additional information on the modeling of coal, reference the multiple works cited in **Section 4** of this report.

5.1 UPSTREAM NATURAL GAS

When the end use of natural gas is a power plant, there are four key steps in the supply chain:

- **Production:** A natural gas production site has a well pad that holds permanent equipment and provides room for development and maintenance activities. The construction of natural gas wells requires a well casing that provides strength to the well bore and prevents contamination of the geological formations that surround the gas reservoir. Well completions are the activities following well drilling and preceding production and, in the case of unconventional wells, involve the injection and flowback of water to stimulate production. Liquids unloading is an intermittent emission from wells that are affected by wellbore fluid accumulation. Other sources of emissions include the gas vented from pneumatically controlled devices and fugitive emissions from flanges, connectors, open-ended lines, and valves. When vapor recovery units are feasible, vented gas is captured and flared; otherwise, vented gas is released to the atmosphere. Production operations also include the combustion of natural gas by reciprocating engines that drive compressors, as well as combustion of natural gas and diesel to provide heat and energy for other supporting equipment.
- **Gathering and Boosting:** Natural gas gathering and boosting networks receive natural gas from multiple wells and transport it to processing or transmission facilities. Gathering and boosting sites include acid gas removal (AGR), dehydration, compressors operations, pneumatic devices and pumps.
- **Processing:** A natural gas processing facility removes impurities from natural gas, which improves its heating value and prepares it for pipeline transmission. Natural gas processing facilities include AGR, dehydration, hydrocarbon liquids removal, and compression operations. When feasible, vapor recovery units capture vented gas and send it to flares. The size and complexity of processing plants are variable; in some cases, processing occurs near production sites, while in other cases a central processing facility receives natural gas from gathering and boosting facilities.
- **Transmission Stations, Storage Facilities, and Transmission Pipelines:** A natural gas transmission system is a network of large pipelines that transport natural gas from processing facilities to the city gate (the point at which natural gas can be consumed by large-scale consumers or transferred to local distribution companies). A typical natural gas transmission pipeline is 32 inches in diameter and is constructed of carbon steel. Transmission pipelines operate at 1,500 pounds per square inch of gauge pressure (psig).

Transmission stations are located along natural gas transmission pipelines and use compressors to boost the pressure of the natural gas. These stations consist of centrifugal and reciprocating compressors; most pipeline compressors are powered by natural gas, but some are powered by electricity. This stage also includes subsurface storage, which can be wells in depleted oil and gas fields, hollowed-out salt domes, or other geological formations. Storage facilities consist of pneumatic devices and compressors, and fugitive emissions coming from flanges, connectors, open-ended lines, and valves for both the storage station and wellhead.

The above processes define the boundaries of upstream natural gas. Distribution is another supply chain step that can follow transmission, but it is not included in the boundaries of this analysis because it moves natural gas from the city gate to small scale end users (commercial or household consumers). This analysis models natural gas used for large scale power generation. Natural gas power plants receive natural gas immediately downstream from natural gas transmission systems or LNG regasification facilities.

Two upstream natural gas profiles are used in this analysis: Appalachian Shale and a conventional mix. Appalachian Shale is used to represent the share of U.S. natural gas exported as LNG. The conventional mix represents a production-weighted composite of 9 conventional natural gas scenarios in the U.S. and is used as a proxy for the non-U.S. scenarios in this analysis. The emission sources for Appalachian Shale and the conventional mix are based on U.S. industry activity in 2016 (the latest year for which data are available to thoroughly characterize emission sources and supply chain throughputs).

NETL's life cycle natural gas model used in this analysis contains 127 unit processes that account for the emissions from production through transmission. These unit processes comprise vented and fugitive emissions that arise from one-time construction and well completions, steady state operations, and episodic maintenance events. A summary of the key parameters used by these unit processes are provided in **Exhibit 5-1** through **Exhibit 5-4**. These parameters are a partial list of the parameters used by NETL's natural gas model, which holds thousands of parameters across different natural gas technologies and production basins. Additionally, the stage scaling parameters used by the model to represent the non-linear relationship between supply stages are included in **Exhibit 5-5**.

The Greenhouse Gas Reporting Program (GHGRP) and the Inventory of U.S. Greenhouse Gas Emissions and Sinks (GHGI) are two data sources that account for most vented and fugitive emissions (EPA, 2016; EPA, 2018). DI Desktop is also used to stratify annual production activity at a basin level (DrillingInfo, 2018). A complete list of parameters and their corresponding uncertainty is provided in NETL's LCA of Natural Gas Extraction and Power Generation (NETL, 2019).

To account for uncertainty, distributions of low, expected, and high values were developed when the data allow. Otherwise, an expected value is given for each parameter. **Exhibit 5-1** through **Exhibit 5-4** display only expected values (despite having parameter distributions) for the sake of brevity. The full parameter tables can be found in the NETL natural gas report (NETL, 2019).

Exhibit 5-1. Key Parameters for Natural Gas Production

Parameter		Units	Basin									
			Anadarko	Appalachian	Arkla	Arkoma	East Texas	Green River	Gulf Coast	Permian	San Juan	Uinta
Basin Mix	Appalachian Shale	fraction	-	1.00	-	-	-	-	-	-	-	-
	Conventional	fraction	0.20	-	0.04	0.03	0.14	0.14	0.07	0.21	0.13	0.05
Estimated Ultimate Recovery		Mcf/well-life	4.37E+06	1.20E+07	2.99E+06	2.74E+06	2.11E+06	4.29E+06	1.07E+07	1.44E+07	1.57E+06	2.21E+06
Production Rate		Mcf/facility-yr*	5.15E+08	7.84E+09	1.43E+08	1.19E+08	1.21E+09	3.09E+08	3.62E+08	4.47E+08	5.72E+08	6.71E+07
CH_4 Content of NG		mass fraction	0.669	0.836	0.849	0.92	0.781	0.766	0.835	0.688	0.719	0.808
Completion Emissions		tonnes CH_4/ facility-yr*	47.3	717	0.545	9.14	19.7	0.150	2.42	52.2	3.20	2.25
Pneumatic Devices†	High Bleed	devices/ facility*	62	25.3	11	95.4	117	32.7	74.6	484	162	55.5
	Intermittent Bleed	devices/ facility*	5,390	2,330	412	2,030	5,690	1,220	5,060	1,670	14,300	1,750
	Low Bleed	devices/ facility*	308	315	2.95	4.9	48.1	58.2	132	107	25,900	3,710
Liquids Unloading Emissions		kg CH_4/kg NG	4.50E-04	5.60E-04	9.38E-03	1.17E-02	1.40E-03	7.00E-04	9.80E-04	9.00E-05	1.04E-02	1.76E-03
Reciprocating Compressors		compressors/ facility*	298	38.5	13.1	65.6	38.9	0.589	228	132	547	1.92
		kg CH_4 vented/ compressor-yr*	180	156	116	182	182	23.1	177	168	182	29.4
Fuel Consumption		Mcf NG/ facility-yr*	2.87E+03	9.1E+03	1.69E+02	1.25E+02	3.81E+02	1.00E+01	3.9E+03	4.75E+02	5.74E+03	3.29E+01
		kg CO_2/Mcf NG combusted	53.8	53.8	53.8	53.8	53.8	53.8	53.8	53.8	53.8	53.8
		kg CH_4/Mcf NG combusted	0.630	0.630	0.630	0.630	0.630	0.630	0.630	0.630	0.630	0.630

* GHGRP defines a production facility as a group of multiple production sites owned by a single operator in a given basin. The GHGRP-based parameters in this table represent a larger production scale than the values used for estimated ultimate recovery. Given this boundary difference, the values for production rate are higher than those for estimated ultimate recovery. NETL's life cycle model normalizes these input parameters to a common basis. Similarly, the equipment counts for the GHGRP data are high under the *conventional* definition for a facility (e.g., 5,390 intermittent bleed devices for an Anadarko facility); however, these counts are reasonable when the GHGRP definition of a facility is understood.

† The following emission factors are applied to pneumatic device counts: high bleed = 622 scf/device-day, intermittent bleed = 218 scf/device-day, low bleed = 23 scf/device-day (EPA, 2018).

Exhibit 5-2. Key Parameters for Natural Gas Gathering and Boosting*

Parameter		Units	Basin									
			Anadarko	Appalachian	Arkla	Arkoma	East Texas	Green River	Gulf Coast	Permian	San Juan	Uinta
Natural Gas Throughput		Mcf/yr	2.06E+08	9.13E+08	3.37E+08	2.78E+08	1.92E+08	2.19E+08	2.3E+08	2.31E+09	2.89E+08	1.06E+08
Pneu-matic Devices	High Bleed	devices/facility	136	29.8	140	3.76	35.1	2.45	190	43.3	33.6	1.09
	Intermittent Bleed	devices/facility	939	515	234	1,874	661	178	1,150	241	535	143
	Low Bleed	devices/facility	420	68	204	203	69	3	352	79	384	30
Fugitive Emissions		tonnes CH_4/facility-yr	3,840	866	535	1,230	884	269	918	3,065	808	2,026
Dehydrator Venting		tonnes CH_4/facility-yr	155	1,689	103	2,096	234	13	91	49	812	7
Fuel Combustion for Compression		Mcf NG/facility-yr	1.04E+07	4.59E+07	1.69E+07	1.43E+07	9.65E+06	1.11E+07	1.18E+07	1.16E+08	1.44E+07	5.33E+06
		kg CO_2/Mcf NG combusted	53.8	53.8	53.8	53.8	53.8	53.8	53.8	53.8	53.8	53.8
		kg CH_4/Mcf NG combusted	0.630	0.630	0.630	0.630	0.630	0.630	0.630	0.630	0.630	0.630

* All parameters in this table are derived from GHGRP. GHGRP defines a gathering facility as a group of multiple gathering sites owned by a single operator in a given basin. The equipment counts and throughput for these data are high under the *conventional* definition for a facility, but they are reasonable within the context of the GHGRP definition of a facility.

Exhibit 5-3. Key Parameters for Natural Gas Processing

Parameter	Units	U.S. Average
Natural Gas Throughput	Mcf/facility-yr	3.36E+07
Acid Gas Removal Venting	kg CH_4/kg NG	3.73E-05
Dehydrator Venting	tonnes CH_4/facility-yr	5.46E+00
Centrifugal Compressor Energy and Fuel Combustion Emission Factors	horsepower	7.65E+04
	operating hours/yr	4,120
	gas-powered turbine thermal efficiency	26%
	lb CO_2 emissions/MMBtu fuel input	110
	lb CH_4 emissions/MMBtu fuel input	8.82E-03
Centrifugal Compressor Venting	tonnes CH_4/facility-yr	2.07E+02
Reciprocating Compressor Energy and Fuel Combustion Emission Factors	horsepower	2.46E+04
	operating hours/yr	4,670
	reciprocating engine thermal efficiency	44%
	lb CO_2 emissions/MMBtu fuel input	110
	lb CH_4 emissions/MMBtu fuel input	1.35
Reciprocating Compressor Venting	tonnes CH_4/facility-yr	9.73E+01
Fuel Consumption	Mcf NG/facility-yr	7.72E+05

Exhibit 5-4. Key Parameters for Natural Gas Transmission, Storage, and Transmission Pipelines

Parameter	Units	U.S. Average
Natural Gas Throughput	Mcf/facility-yr	1.24E+08
Transmission Facility Blowdowns	tonnes CH_4/facility-yr	1.26E+02
Centrifugal Compressor Power	horsepower	2.48E+04
Centrifugal Compressor Venting	tonnes CH_4/facility-yr	6.21E+01
Reciprocating Compressor Power	horsepower	1.11E+04
Reciprocating Compressor Venting	tonnes CH_4/facility-yr	1.18E+02
Equipment Leaks	tonnes CH_4/facility-yr	2.39E+01
Pipeline Length	km	4.84E+05
Pipeline Fugitive Emission Factor	kg CH_4/km	6.96E+02

The life cycle model used in this analysis normalizes natural gas system flows to a single basis, the delivery of 1 MJ of natural gas to consumers. The relationships among supply chain stages do not necessarily represent a single pathway with all stages connected in series. The following pathways are resolved to express results as a unit of delivered natural gas:

- Most (but not all) natural gas goes through gathering and boosting facilities.
- Most (but not all) natural gas goes through processing facilities.
- Natural gas goes through multiple transmission stations.
- Storage facilities do not represent a natural gas throughput, but an internal loop within the transmission network with storage and withdrawal.

Exhibit 5-5. Stage Scaling Parameters

Stage (or sub-stage)	Triangular Distributions			Units	Rationale
	Low	Expected	High		
Production		1		facility count	Natural gas is extracted from a well exactly one time.
Gathering and boosting	0.8	0.9	1	dimensionless	The fraction of natural gas that goes through gathering and boosting is based on a recent measurement study (Marchese et al., 2015).
Processing	0.56	0.61	0.66	dimensionless	The total volume of U.S. annual processing throughput is 61% of annual natural gas delivered (EIA, 2017a).
Transmission	6.8	10.2	14.5	station count	Transmission station count is based on literature review of inter- and intra-state transmission station counts, reconciled by average facility throughput to estimate the number of transmission stations between processing and delivery.
Storage		0.37		dimensionless	The United States has 0.37 units of storage capacity per unit of delivered natural gas. This factor is the ratio of total underground storage capacity (9.2 Tcf) to annual gas delivered (25 Tcf) (EIA, 2017a).
Pipelines	540	600	660	pipeline miles	Data for pipeline blowdown events are translated to an emission factor in terms of emissions per pipeline mile, thus requiring a corresponding activity factor in terms of pipeline miles traveled by average natural gas. The average distance of transmission is 600 miles (NETL, 2016).

The scaling parameters in **Exhibit 5-5** should be interpreted in the context of an average unit of natural gas flowing through the supply chain. For example, using the information from the expected column in **Exhibit 5-5**, the pathway for average natural gas can be described as follows: After leaving a production site, 90% of natural gas goes through gathering and boosting stations, 61% goes through a processing plant, and travels 600 miles through 10.2 transmission stations.

The Russian natural gas scenario uses the upstream parameters shown in **Exhibit 5-1** through **Exhibit 5-4**, but uses a separate profile for natural gas pipeline transmission. The Russian scenario was modeled using a unit process that allows for the adjustment of pipeline distance and its effect on energy consumption and emissions. Modeling parameters for pipeline distance are included in **Exhibit 5-6**. The pipeline distance was calculated based on the great circle distance between the Yamal district of Siberia, Russia to a power plant located in Rotterdam, Netherlands or Shanghai, China. The great circle distance is the shortest possible distance between two points on a sphere and was therefore used to represent the shortest possible pipeline distance between the extraction source and the power plant. An additional 1,000 km of pipeline transport were added to the great circle distance to specify the expected pipeline transport distance. Given the extensive pipeline networks in Europe and Asia, determining an actual distance was not possible, nor was it required for this level of analysis. This assumption is tested in the uncertainty analysis section of this study.

Exhibit 5-6. Key Modeling Parameters for Natural Gas Export – Russian Cases

Model Parameter		Low	Expected	High	Distribution
Pipeline Distance (km)	Yamal, Russia to Rotterdam, Netherlands	3,792	4,792	5,792	Triangular
	Yamal, Russia to Shanghai, China	5,448	6,447	7,446	Triangular

5.2 LNG Supply Segment

There are four key steps in the LNG segment of the natural gas supply chain:

- **Liquefaction:** This step includes the pre-treatment of pipeline quality gas to make it suitable for liquefaction by removal of CO_2, H_2S, water and heavy hydrocarbons to prevent freezing and plugging in the downstream units. The pre-treated gas is then liquefied by reducing its temperature to approximately -160°C (API, 2015) and stored until it can be loaded. Boil-off gas is generated during storage, which is continuously removed and re-liquefied to maintain the temperature in the storage tanks.
- **Loading and Unloading:** The stored LNG from the liquefaction facility is loaded on an ocean tanker for transportation and unloaded into the storage tanks of the regasification facility after transport. The Boil-off Gas (BOG) generated during loading and unloading is re-liquefied on-site and added back to the supply-chain.
- **Ocean Transport:** Ocean tankers are the transportation method used to move LNG from the U.S. to Asian and European markets (Pace Global, 2015). Approximately 98 percent of an ocean tanker's capacity is able to be loaded with LNG (Hasan et al., 2009). The BOG generated during this journey is compressed and used for fuel, with Ultra Low Sulfur

Diesel (ULSD) used as supplementary fuel. Once the LNG is unloaded at the regasification facility, the ocean tanker begins its ballast voyage with approximately 2.5 percent capacity still onboard, which is used to maintain the temperature of the tanker to avoid cooling it down on arrival at the liquefaction facility for the next journey (Cheniere Energy, 2018).

- **Regasification:** The imported LNG is regasified at the facility to make it suitable for pipeline transportation to the power plant and combustion to generate power. The Open Rack Vaporizer (ORV) technology passes the LNG through a heat exchanger with sea water and regasifies it.

The parameters and modeling choices used in the unit processes corresponding to these steps in the LNG supply chain are provided in detail in **Appendix B.**

Key modeling parameters for the liquefaction through regasification portion of the LNG supply chain are included below in **Exhibit 5-7** through **Exhibit 5-11**. Unless otherwise noted, these parameters are used for all LNG scenarios.

Exhibit 5-7. Key Modeling Parameters for Liquefaction

Model Parameter		Low	Expected	High	Distribution	Units	Reference
Energy Requirement	Adsorption Based HHC* Removal, with HRSG*		2.86		Point Estimate	MJ/kg NG liquefied	Mallapragada et al., 2018
Energy Requirement	Adsorption Based HHC, without HRSG		3.08		Point Estimate	MJ/kg NG liquefied	Mallapragada et al., 2018
Energy Requirement	Cryogenic Distillation Based HHC removal, with HRSG		2.78		Point Estimate	MJ/kg NG liquefied	Mallapragada et al., 2018
Energy Requirement	Cryogenic Distillation Based HHC removal, without HRSG		3.35		Point Estimate	MJ/kg NG liquefied	Mallapragada et al., 2018
Boil-off Rate (temporary storage)		0.02%		0.1%	Uniform	percent volume/day	Dobrota et al., 2013
Storage Time		1.33		1.60	Uniform	days	EIA, 2017b; IGU, 2017
Power Consumption for BOG Recondenser			4,450		Point Estimate	kW/kg BOG condensed	Li & Wen, 2016
Handling Capacity of BOG Recondenser			13.38		Point Estimate	tonne/hour	Kinder Morgan, n.d.; Li & Wen, 2016

**HHC stands for heavy hydrocarbon removal and HRSG stands for heat recovery steam generator*

Exhibit 5-8. Key Modeling Parameters for Loading/Unloading

Model Parameter	Low	Expected	High	Distribution	Units	References
Standard Loading/Unloading Rate	10,000		12,000	Uniform	m^3/hour	Dobrota et al., 2013
Boil-off Rate		20,000		Point Estimate	kg/hour	Dobrota et al., 2013

The modeling parameters for ocean transport (**Exhibit 5-9**) represent the input parameters for this unit process. These parameters are used to calculate values such as fuel use and boil-off gas generation. Separate combustion emission factors are used to calculate the emissions for ocean transport. These calculations are performed within the model, they are not an input to the model.

Exhibit 5-9. Key Modeling Parameters for Ocean Transport

Model Parameter	Low	Expected	High	Distribution	Units	Reference
Ship Speed, Laden		19.5		Point Estimate	knots	Pace Global, 2015
Ship Speed, Ballast		20.9		Point Estimate	knots	Pace Global, 2015
Ship Capacity	150,000		180,000	Uniform	m^3	IGU, 2017
Available Volume		98%		Point Estimate	percent	Hasan et al., 2009
Percent Heel		2.5%		Point Estimate	percent	Cheniere Energy, 2018
Boil-Off Rate		0.1%		Point Estimate	percent volume/day*	IGU, 2017
Engine Power		31,400		Point Estimate	kW	MAN Diesel and Turbo, 2013
Gas Consumption, 100% Load		7,318		Point Estimate	kJ/kWh	Wärtsilä, 2018
Oil Consumption, 50% Load		0.1904		Point Estimate	kg/kWh	Wärtsilä, 2018
Oil Consumption, 75% Load		0.1844		Point Estimate	kg/kWh	Wärtsilä, 2018
Oil Consumption, 100% Load		0.1896		Point Estimate	kg/kWh	Wärtsilä, 2018

**The number of days for a journey is a function of the distance (Exhibit 5-10) and the Ship Speed*

Without data to inform the likelihood that any one transportation route is taken, all shipping routes stated below in **Exhibit 5-10** were assumed to be equally likely. The results shown in **Section 6** are reflective of the average impact between any two export and import terminals, where all transportation routes were treated with equal weight. In scenarios with multiple transportation routes, the result with the lowest impact and the result with the highest impact were used to inform the uncertainty bars. This was not necessarily equivalent to the scenarios with the shortest and longest transportation distances.

Exhibit 5-10. Ocean Transport Distances – LNG scenarios

Export Terminal	Import Terminal	Via	Distance (km)	
New Orleans, U.S.	Rotterdam, Netherlands	Direct	8,990	Sea-Distances.org, 2016
New Orleans, U.S.	Shanghai, China	Panama Canal	18,544	Sea-Distances.org, 2016
		Suez Canal	25,436	Sea-Distances.org, 2016
		Cape of Good Hope	27,731	Sea-Distances.org, 2016
		Strait of Magellan	31,606	Sea-Distances.org, 2016
		Cape Horn	31,722	Sea-Distances.org, 2016
Oran, Algeria	Rotterdam, Netherlands	Strait of Gibraltar	2,956	Sea-Distances.org, 2016
		Cape of Good Hope	24,427	Sea-Distances.org, 2016
Darwin, Australia	Shanghai, China	Direct	5,444	Sea-Distances.org, 2016

Exhibit 5-11. Key Modeling Parameters for Regasification

Model Parameter	Low	Expected	High	Distribution	Units	Reference
Energy Requirement		2.14E-01		Point Estimate	MJ/kg LNG regasified	Pace Global, 2015
Electricity Consumption		1.21E-05		Point Estimate	MWh/kg LNG regasified	Papadopoulo et al., 2011
Boil-Off Rate	0.02%		0.1%	Uniform	percent volume/day	Dobrota et al., 2013
Storage Time	1.33		1.60	Uniform	days	EIA, 2017b; IGU, 2017
Fugitive Emission Rate		0.009%		Point Estimate	kg/kg LNG regasified	Papadopoulo et al., 2011

5.3 COAL UPSTREAM

The coal scenario is sensitive to changes in coal type and rail transport distance. The key parameters for the upstream coal supply chain are summarized below in **Exhibit 5-12**.

Exhibit 5-12. Key Modeling Parameters for Coal Upstream

Model Parameter	Low	Expected	High	Distribution	Reference
Coal Mine Methane (scf/ton)	8	8	360	Triangular	NETL, 2010b; NETL, 2010c; NETL, 2012
Coal Type	PRB	PRB	I-6	Triangular	NETL, 2010b; NETL, 2010c; NETL, 2012
Rail Transport Distance (km)	362	1,167	1,971	Triangular	Estimate

5.4 Power Plant and Transmission & Distribution

Lastly, key modeling parameters for the power plant and transmission and distribution portion of the supply chain are included in **Exhibit 5-13*.*** All scenarios are sensitive to variability in power plant net efficiency.

Exhibit 5-13. Key Modeling Parameters for Power Plant and Transmission & Distribution (All Scenarios)

Scenario/Parameter	Low	Expected	High	Distribution	Reference
All LNG Cases – Power Plant Net Efficiency	41.2%	46.4%	49.2%	Triangular	NETL, 2019
Russian Natural Gas – Power Plant Net Efficiency	41.2%	46.4%	49.2%	Triangular	NETL, 2019
Regional Coal – Power Plant Net Efficiency	28.3%	33.0%	36.7%	Triangular	NETL, 2014a
All Scenarios – Electricity T&D Loss	7%			Point Estimate	NETL, 2013a

6 Results

The LCA results for natural gas and coal power generation in Europe and Asia are shown in **Exhibit 6-1** and **Exhibit 6-2**, respectively. The results in both exhibits are shown on both 100-yr and 20-yr GWP timeframes, which is important due to the uncaptured venting and fugitive emissions of methane in natural gas systems. Detailed results inventory for all of the scenarios in these exhibits are provided in **Appendix A.** It is important to note that the results from this analysis bracket the range of variability based on the cumulative change to the key parameters. **Exhibit 6-1** and **Exhibit 6-2** report an expected value for each of the scenarios. These values should not be interpreted as the most likely values due to the wide range of scenario variability and uncertainty in the underlying modeled data. Rather, the expected values allow for the evaluation of the contribution of each of the major processes to the total life cycle emissions (e.g., extraction, transport, combustion). The results should be interpreted as general guidance to provide perspective on trends only and not as prescriptive, scenario-specific results.

Exhibit 6-1. Life Cycle GHG Emissions for Natural Gas and Coal Power in Europe

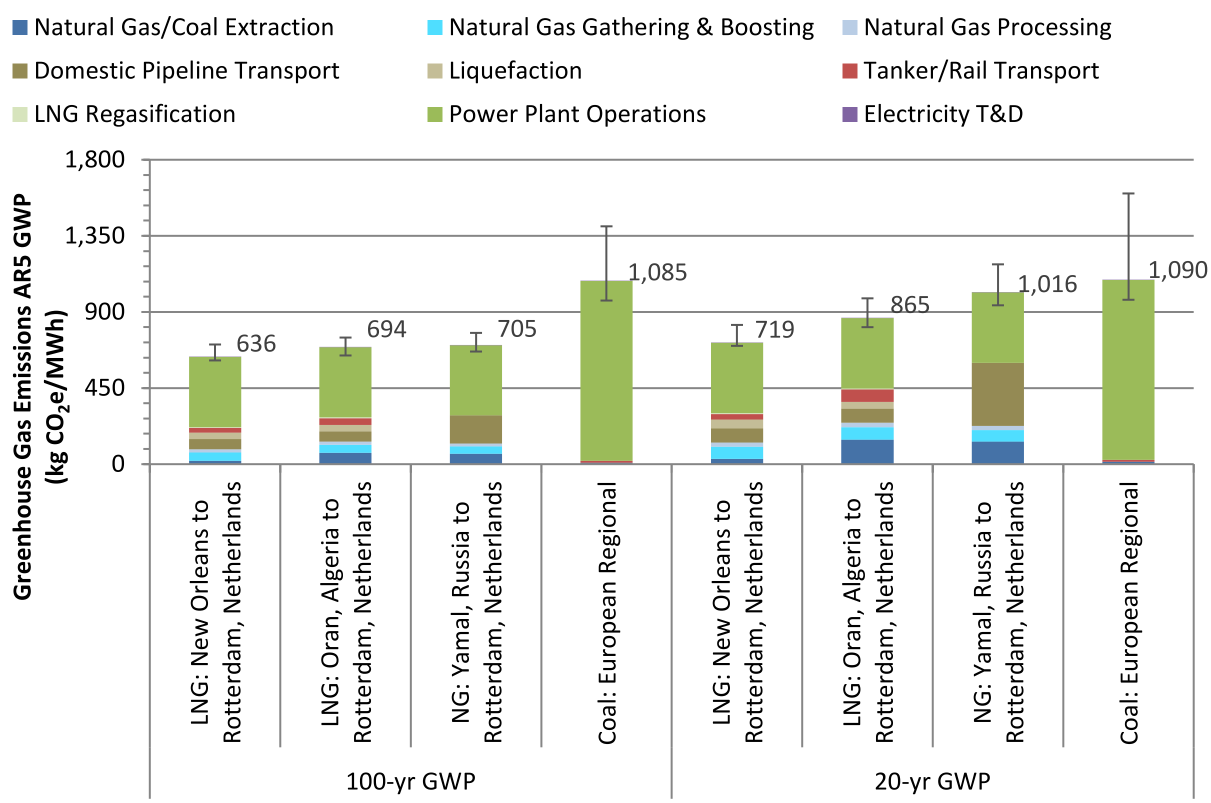
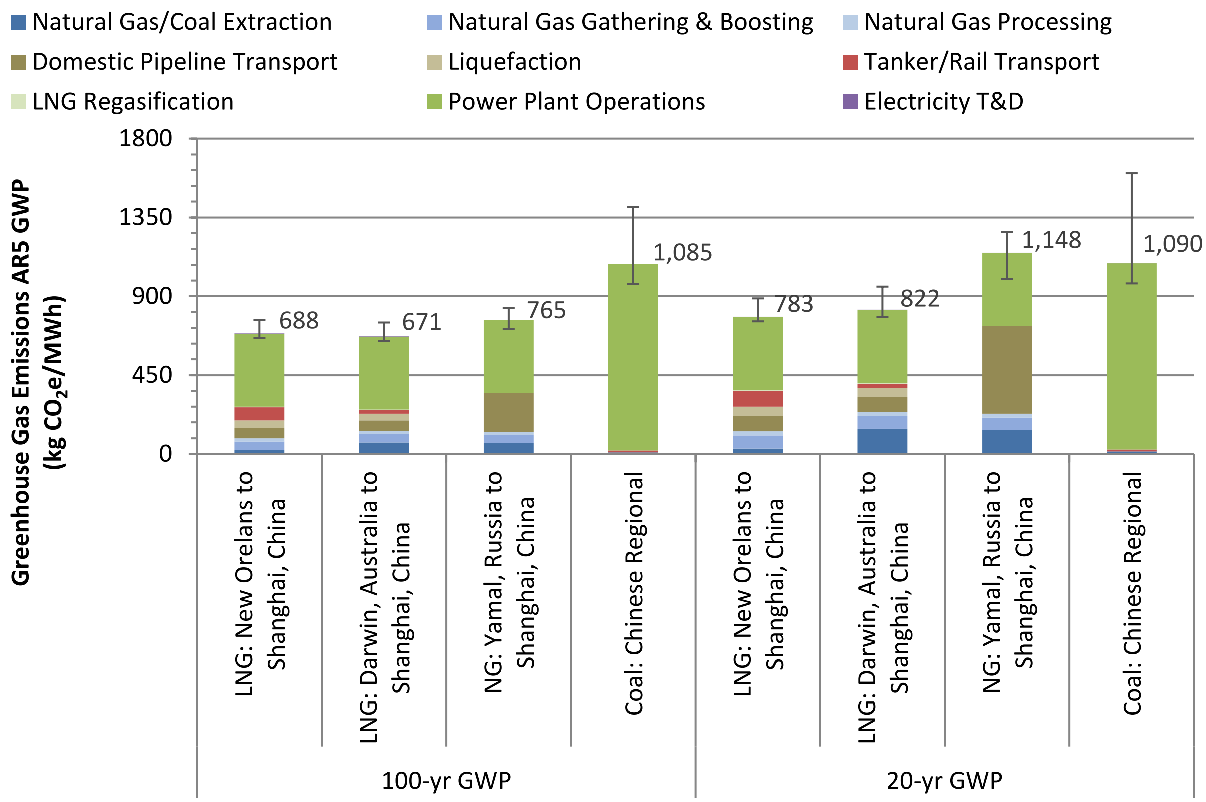


Exhibit 6-2. Life Cycle GHG Emissions for Natural Gas and Coal Power in Asia



The results from **Exhibit 6-1** and **Exhibit 6-2** show that for all 100-yr time horizon scenarios the generation of power from natural gas has lower life cycle GHG emissions than power generation from regional coal. The European and Asian coal scenarios are identical because the same parameter ranges are used for both. The interpretation of the 20-yr natural gas scenarios is more complex due to the tradeoff between upstream GHG intensities and end use efficiencies. Specific conclusions are as follows:

- On a 20-yr GWP time horizon, the Russian natural gas and Algeria LNG scenarios have overlapping error bars with the regional coal scenarios.
- The U.S. LNG to Europe and Asia and the Australia LNG scenarios do not overlap the regional coal scenario on a 20-yr time horizon.

On both time-horizons, uncertainty in the natural gas supply chain obfuscates upstream stage-wise comparisons among scenarios, but confidence in scenario-specific transport distances is a key differentiator.

Exhibit 6-1 and **Exhibit 6-2** show that the majority of GHG emissions come from combustion at the power plant; however, the contributions from the upstream acquisition of the two fuels are very different. For the natural gas scenarios, 34 to 45 percent of the life cycle emissions are from the natural gas supply chain prior to the power plant, compared to 2 percent for coal on a

100-yr basis. On a 20-yr basis, the upstream share (prior to power plant) for the natural gas scenarios increases to 42 to 64 percent, compared to 2 percent for coal, due to the high GWP associated with methane. The results show that the LNG and Russian natural gas cases produce essentially the same amount of GHG emissions on a 100-yr basis, with a significant portion of uncertainty bars overlapping. The emissions from the steps involved in LNG (liquefaction, tanker transport, and regasification) are lower than the pipeline transport emissions for the Russian natural gas cases, and the difference within the LNG scenarios is influenced only by the ocean transport distances. However, when comparing the scenarios on a 20-yr basis, the difference between the LNG and Russian natural gas cases is more significant, but there is still some overlap in the uncertainty bars in the Algeria to Rotterdam scenario. This is driven by the pipeline contribution to the Russian natural gas GHG results. The majority of pipeline emissions are methane, which has a higher GWP on a 20-yr basis.

Compared to domestically produced and combusted gas, there is a significant increase in the life cycle GHG emissions that are attributed to the LNG supply chain, specifically from liquefaction, tanker transport, and regasification processes. **Exhibit 6-3** shows the speciated GHGs from the key stages in the natural gas power production life cycle for the U.S. LNG to Rotterdam scenario on a 100-yr GWP basis. The liquefaction, ocean transport, and regasification of natural gas are energy intensive activities with significant GHG emissions, accounting for 11 percent of the cradle-to-grave emissions in this scenario. For comparison, the natural gas extraction, processing, and transport activities in the exporting country (either United States or regional) account for 23 percent of the cradle-to-grave emissions. In this analysis, Appalachian Shale natural gas is used as an example, but the same patterns would be shown for other types of natural gas. As shown by **Exhibit 6-3**, methane emissions account for 9 percent of the total life cycle GHG emissions, while CO_2 accounts for 90 percent. The total emissions from the plant stack account for 65 percent of the total life cycle GHG emissions.

For comparison, a speciated GHG drilldown is also shown for the Russian natural gas to Rotterdam scenario in **Exhibit 6-4** on a 100-yr GWP basis. In that scenario, methane emissions account for 31 percent of the total life cycle GHG emissions, while CO_2 accounts for 69 percent. In the Russian scenario, 59 percent of the total life cycle GHG emissions are direct emissions from the power plant stack. The increased percentage of methane emissions is the result of larger methane emissions from the longer pipeline transport distance.

Exhibit 6-5 shows a speciated GHG drilldown for the coal power production case on a 100-yr GWP basis. Methane emissions, primarily from releases during coal mining, account for 0.4 percent of the total life cycle GHG emissions, compared to 99 percent for CO_2. The contribution of methane to the total life cycle GHG emissions for the coal scenario is significantly less than for the natural gas scenarios. For the coal power plant, 98 percent of life cycle GHG emissions come directly from the power plant. As shown by the exhibits, the upstream extraction, processing, and transport emissions are much more significant for the natural gas supply chain than for coal.

Exhibit 6-3. Speciated Life Cycle GHG Emissions of Natural Gas Power – U.S. LNG to Rotterdam Scenario

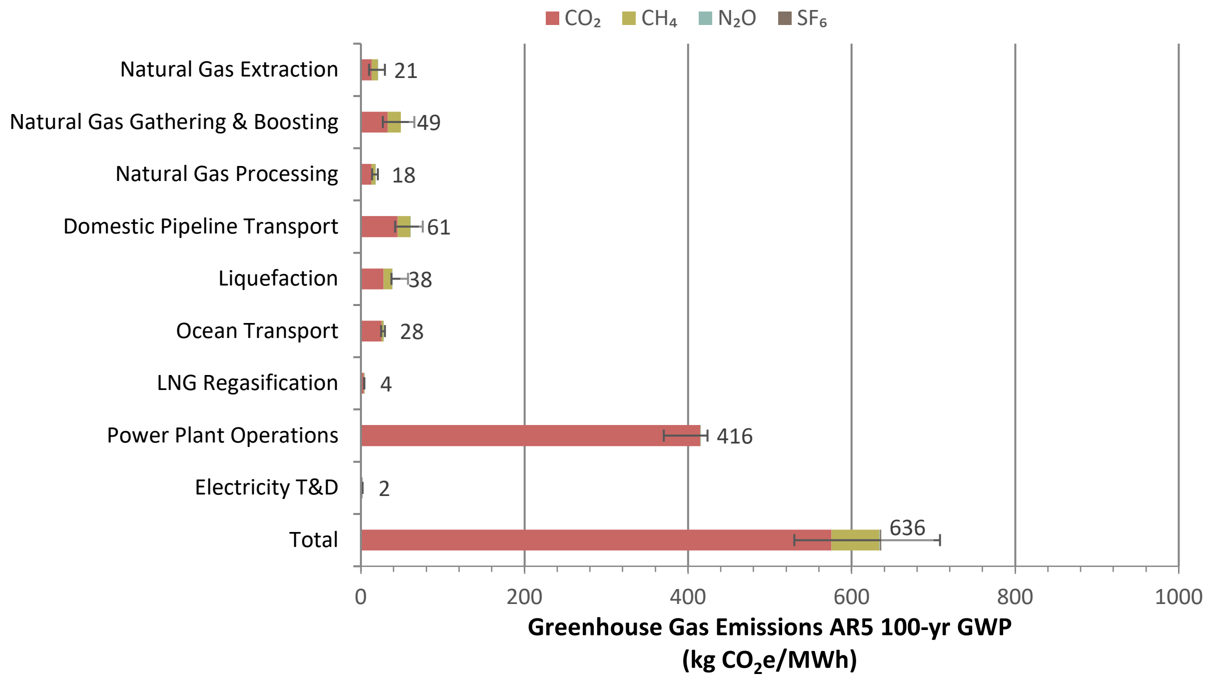


Exhibit 6-4. Speciated Life Cycle GHG Emissions of Natural Gas Power – Russian NG to Rotterdam Scenario

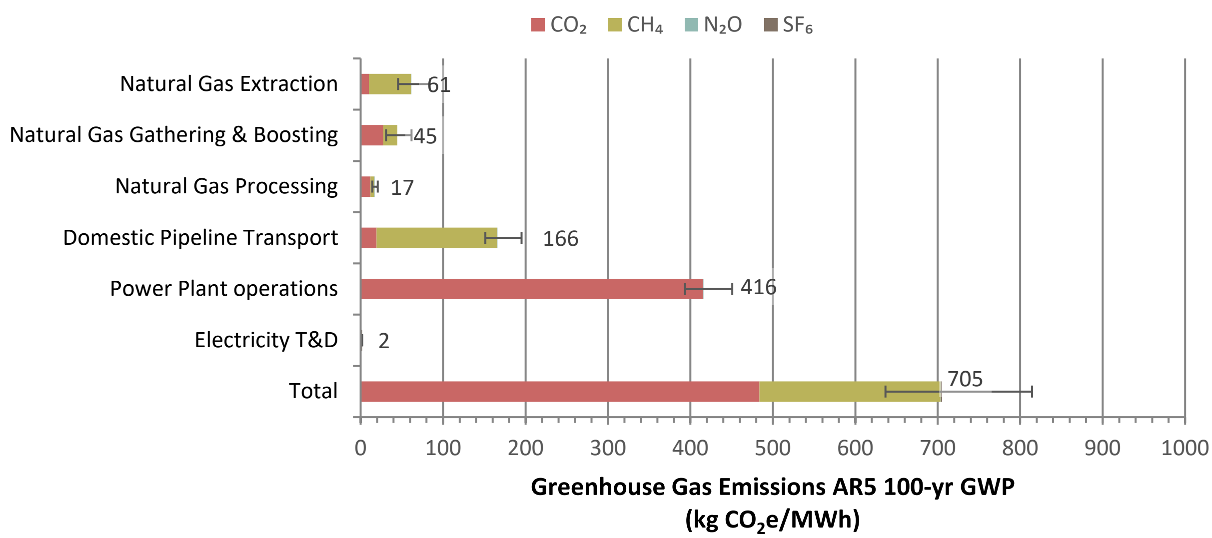


Exhibit 6-5. Speciated Life Cycle GHG Emissions of Coal Power

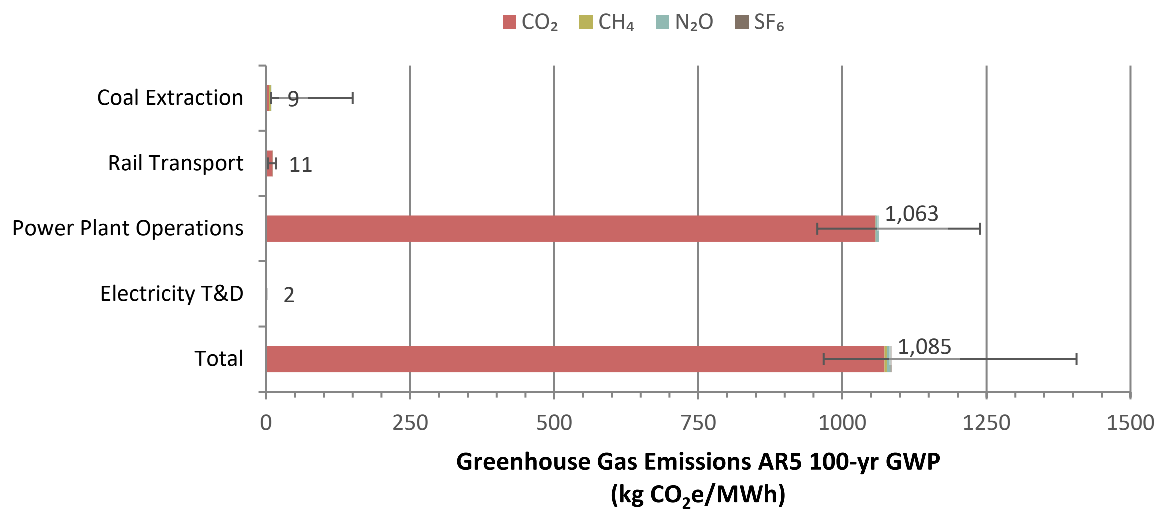


Exhibit 6-6 and **Exhibit 6-7** use the uncertainty bars shown in **Exhibit 6-1** and **Exhibit 6-2** to compare the range of life cycle GHG emissions for the gas and coal scenarios in Europe and Asia on 100-yr and 20-yr bases. To calculate the range of difference between natural gas and coal scenarios, the minimum GWP of LNG and NG is compared to the maximum GWP of the coal scenario, and then the maximum GWP of LNG and NG is compared to the minimum GWP of the coal scenario. On a 100-yr basis, natural gas power is 20 to 53 percent less than coal for Europe and 14 to 49 percent less than coal for Asia. Liquefied natural gas power is 23 to 56 percent less than coal for Europe and 21 to 54 percent less than coal for Asia. The small difference in the ranges for Europe and Asia is driven by the longer transport distances for natural gas to Asia (both LNG from the United States and pipeline from Russia). On a 20-yr basis, there is still potential for natural gas and liquefied natural gas to have lower GHG emissions than coal, however natural gas and LNG scenario upper-bound results overlap with coal lower-bound results to some extent. LNG to Europe is 56 percent less to 1 percent greater than coal, and LNG to Asia is 2 to 53 percent less than coal. Russian gas to Europe ranges from 41 percent less to 22 percent greater than coal, and Russian gas to Asia ranges from 38 percent less to 30 percent greater than coal. As noted, the 20-yr GWP emissions for the Russian natural gas scenarios are driven by the methane emissions from pipeline transport. The estimated pipeline distances for Russian natural gas transport are roughly four to eight times longer than for the LNG cases.

Exhibit 6-6. 100-yr GWP Comparison of Coal and Natural Gas Power in Europe and Asia

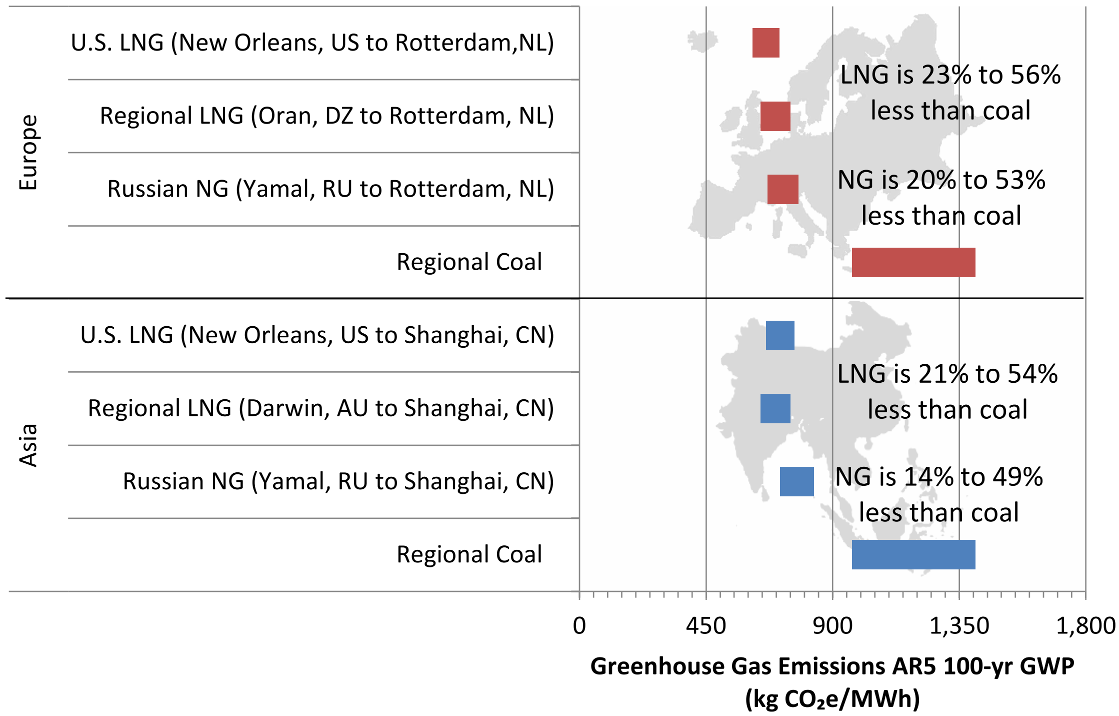
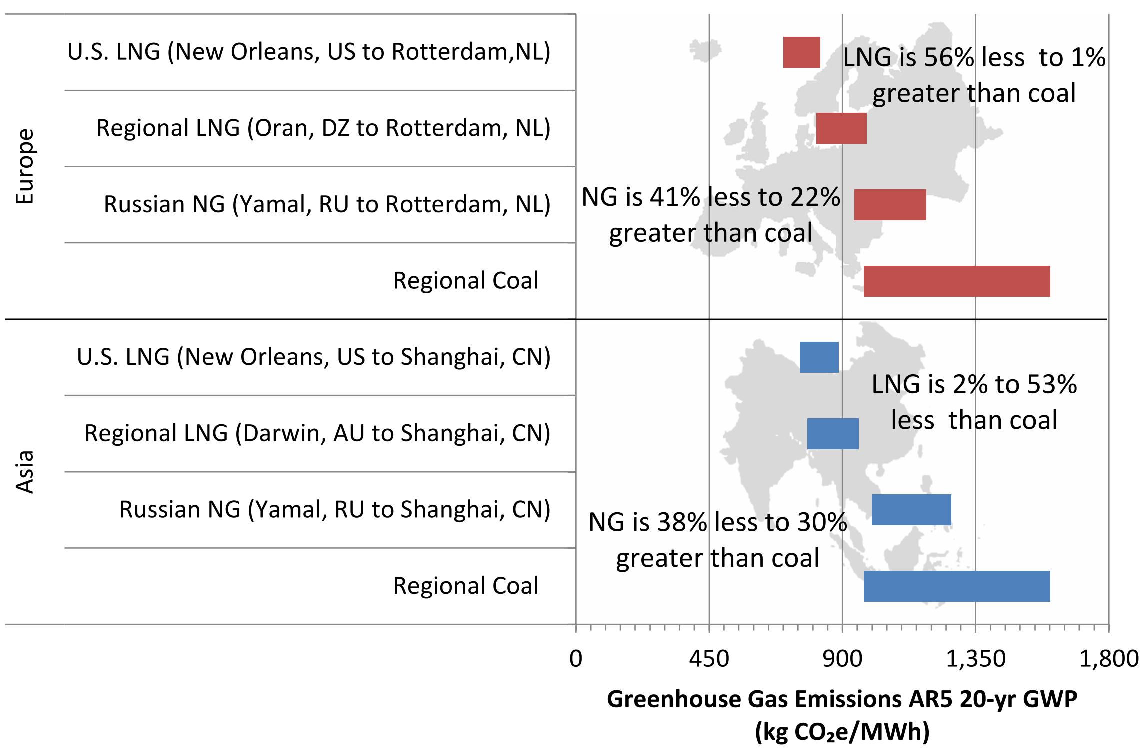


Exhibit 6-7. 20-yr GWP Comparison of Coal and Natural Gas Power in Europe and Asia



The methane emission rates for the natural gas supply chains are presented in **Exhibit 6-8** for two different boundaries, as defined below.

Upstream emission rate: Comprises cradle-through-transmission methane emissions for natural gas delivered to a liquefaction terminal or, for the Russian scenario, natural gas delivered directly to a natural gas-fired power plant. The numerator for this emission rate is methane emissions from production through pipeline transmission. The denominator for this emission rate is natural gas that exits a transmission pipeline.

Cradle-through-delivery emission rate: Comprises cradle-through-delivery methane emissions for natural gas delivered to a natural gas-fired power plant. For the LNG scenarios, this includes upstream emissions plus the emissions from the LNG segment of the supply chain. For the Russian scenario, the upstream emission rate and cradle-through-delivery emission rate have identical boundaries. The numerator for this emission rate is methane emissions from production through regasification. The denominator for this emission rate is natural gas that exits a regasification facility.

This analysis employs the above two emission rate boundaries as a way of reconciling two conventions. *Upstream* emission rate is the most common convention for reporting methane emission rates; it is appropriate for domestic supply chains where additional transport steps (such as those used by the LNG supply segment) are not used. *Cradle-through-delivery* emission rate is used as an alternate definition in this analysis because the LNG supply segment has losses in addition to those from the upstream supply chain, thus changing the numerator and denominator for the emission rate. The life cycle results for this analysis are expressed per MWh of electricity delivered to consumers and do not change when switching between the two methane emission rate definitions.

Exhibit 6-8 shows the upstream and cradle-through-delivery methane emission rates for all scenarios. It also shows the breakeven upstream emission rates for each scenario; breakeven rates were calculated by comparing the expected results for natural gas to the expected results for coal. The breakeven rates for the 20-yr GWP are lower than those for the 100-yr GWP because methane has a higher GWP over 20 years than it does over 100 years.

Exhibit 6-8. Coal and Natural Gas Breakeven for U.S. LNG and Russian Natural Gas Scenarios

Scenario	Upstream Emission Rate	Cradle-through-delivery Emission Rate	Breakeven Upstream Emission Rate		Breakeven Upstream Emission Rate/ Upstream Emission Rate	
			100-yr GWP	20-yr GWP	100-yr GWP	20-yr GWP
U.S. LNG to Rotterdam	0.7%	1.1%	9.1%	3.6%	12.8	5.1
U.S. LNG to Shanghai	0.7%	1.2%	8.2%	3.1%	11.5	4.4
Russia NG to Rotterdam	4.1%	4.1%	11.2%	4.7%	2.7	1.1
Russia NG to Shanghai	5.1%	5.1%	11.1%	4.6%	2.2	0.9
Algeria LNG to Rotterdam*	1.5%	2.1%	8.9%	3.3%	5.9	2.2
Australia LNG to Shanghai*	1.5%	2.0%	9.3%	3.6%	6.2	2.0

**Scenarios not included in Exhibit 6-9 and 6-10*

Exhibit 6-9 and **Exhibit 6-10** show life cycle GHG emissions for the U.S. LNG and Russian natural gas scenarios as a function of upstream emission rate. **Exhibit 6-9** shows life cycle GHG emissions using 100-yr GWP, and **Exhibit 6-10** shows life cycle GHG emissions using 20-yr GWP. Both exhibits also include a reference line for the coal power scenario. The diamond-shaped data points represent the emission rate for each scenario and the circular data points represent the breakeven emission rate at which the cradle-through-delivery GHG emissions for natural gas power would equal those for the coal reference case.

The breakeven upstream emission rates for U.S. LNG to Shanghai and Rotterdam are 8.2 and 9.1 percent, respectively. On a 100-yr GWP basis, the upstream emission rate would have to increase by a factor of 11.5 before the expected life cycle GHG emissions matched those for coal-fired power in China. To match coal-fired power in Europe, the upstream emission rate would have to increase by a factor of 12.8 for the U.S. LNG to Rotterdam scenario. This breakeven point is higher than the U.S. LNG to Shanghai scenario due to the shorter transport distance between the U.S. and Rotterdam.

The upstream methane emission rates for Russian natural gas to Shanghai and Rotterdam are 5.1 and 4.1 percent, respectively. On a 100-yr GWP basis, the upstream emission rate would have to increase by a factor of 2.2 before the expected life cycle GHG emissions matched those for coal-fired power in China. To match coal-fired power in Europe, the upstream emission rate would have to increase by a factor of 2.7 for the U.S. LNG to Rotterdam scenario.

Exhibit 6-10 shows breakeven points for the U.S. and Russian scenarios on a 20-yr GWP basis. The upstream emission rate for U.S. LNG (0.7 percent) is still lower than the breakeven upstream emission rates for the corresponding Rotterdam and Shanghai scenarios (3.6 percent and 3.1 percent, respectively). The upstream emission rate for Russian natural gas to Rotterdam (4.1 percent) is also lower than the breakeven upstream emission rate (4.7 percent) on a 20-yr basis, but Russian natural gas to Shanghai scenario has an upstream emission rate (5.1 percent) that is higher than the breakeven upstream emission rate (4.6 percent).

Exhibit 6-9. Coal and Natural Gas Breakeven for U.S. LNG and Russian Natural Gas Scenarios (100-yr GWP)

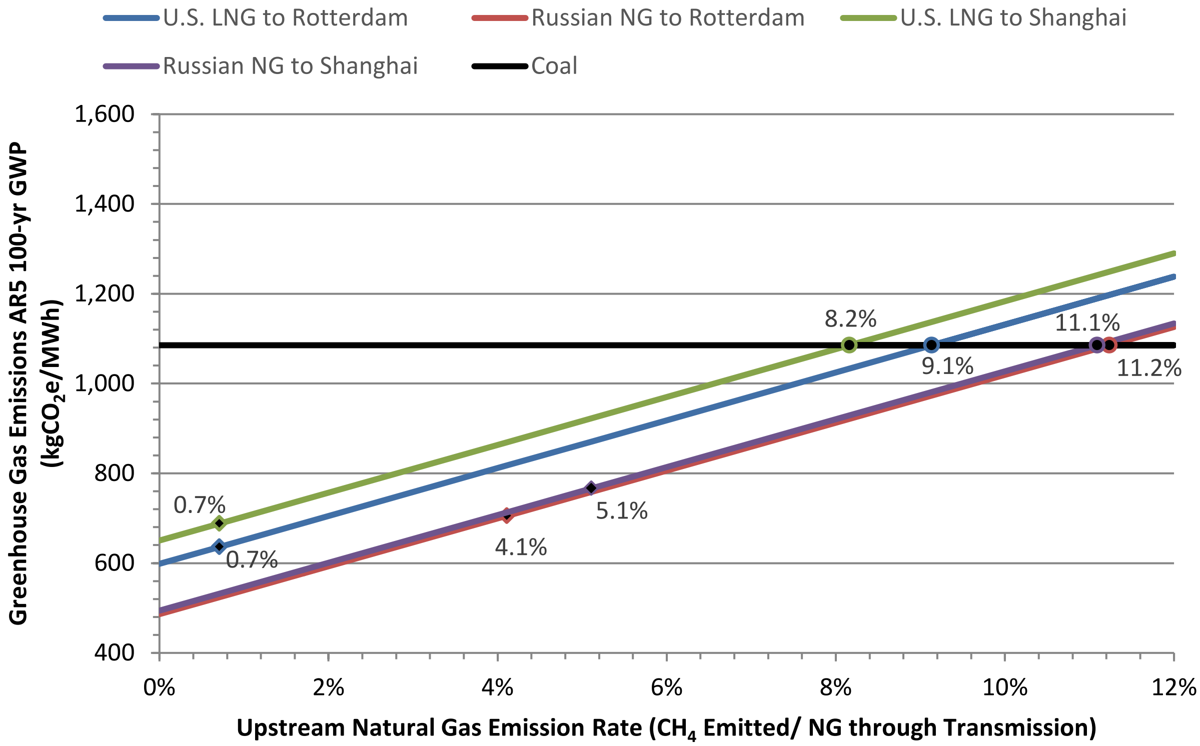


Exhibit 6-10. Coal and Natural Gas Breakeven for U.S. LNG and Russian Natural Gas Scenarios (20-yr GWP)

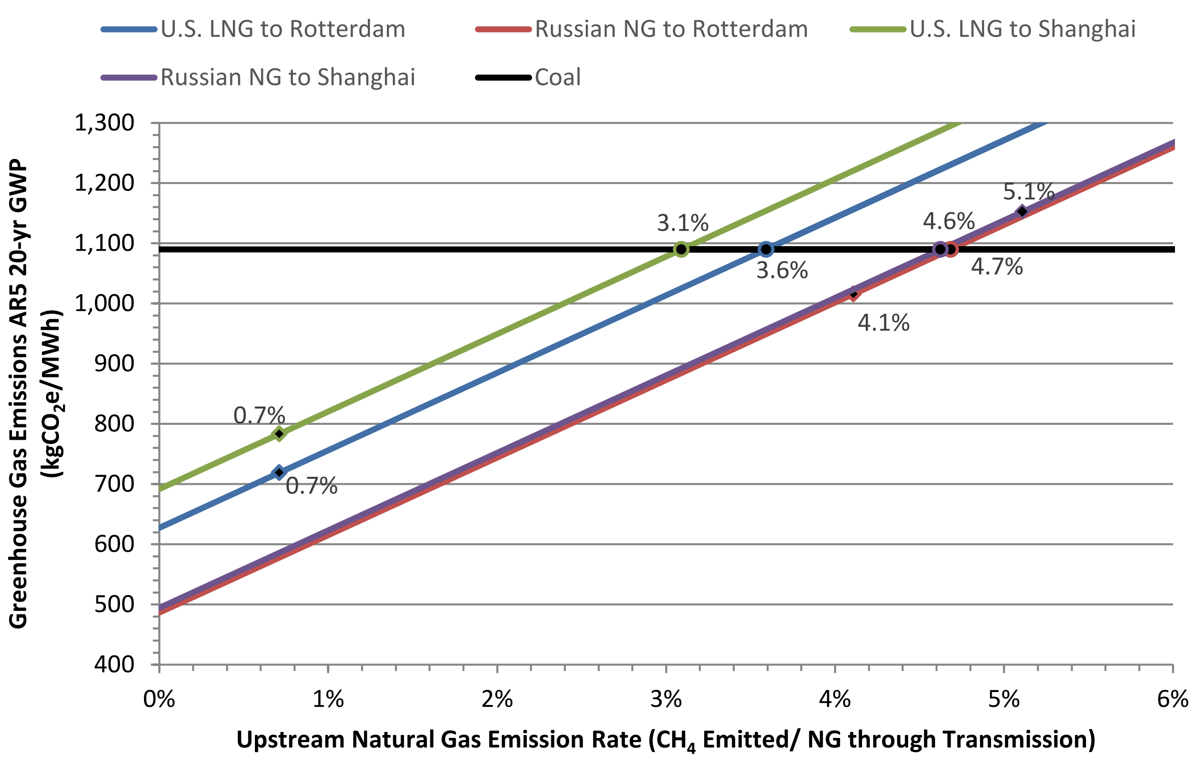


Exhibit 6-11 through **Exhibit 6-17** are uncertainty tornado diagrams for each of the 100-yr GWP scenarios from **Exhibit 6-1** and **Exhibit 6-2**. The parameter ranges for these exhibits are based on the values in **Exhibit 5-1** through **Exhibit 5-13**. These exhibits show the uncertainty in the total life cycle results based on changes to only a single parameter.

As expected, the power plant efficiency contributes a significant fraction of the uncertainty for the natural gas and coal scenarios. **Exhibit 6-11** through **Exhibit 6-17** indicate that the transport of LNG does not have any uncertainty in the New Orleans to Rotterdam and Darwin to Shanghai cases (as only one route is modeled), but contributes significantly in the Oran to Rotterdam and New Orleans to Shanghai cases. In the Oran to Rotterdam and New Orleans to Shanghai scenarios, two and five possible shipping routes are considered, respectively (as described in **Exhibit 5-10**). The base case assumption for these scenarios is the average of all likely routes. The emissions associated with the extraction and processing of natural gas are significant contributors to the uncertainty of the overall emissions in all natural gas scenarios. For more details on the factors that drive the uncertainty of upstream natural gas extraction, refer to the NETL *Life Cycle Analysis of Natural Gas Extraction and Power Generation* (NETL, 2019). For the Russian natural gas cases shown in **Exhibit 6-15** and **Exhibit 6-16**, uncertainty in the pipeline transport distance results is a large driver in the overall uncertainty of the life cycle result. As previously noted, the exact distance the natural gas travels from the extraction point in Yamal to the destination power plant is unknown, so a wide range spanning 2,000 km (1,243 miles) from low to high was used to represent all potential scenarios.

Exhibit 6-17 shows the uncertainty within the coal model used for both the Asian and European cases. The type of coal used at the power plant is one source of uncertainty. The high case uses I-6 coal, which has higher acquisition emissions due to higher methane emissions at the coal mine. The low and expected cases use PRB coal, and so have the same value for coal mine methane emissions.

Exhibit 6-11. Uncertainty Tornado LNG – U.S. LNG (New Orleans) to Rotterdam, Netherlands

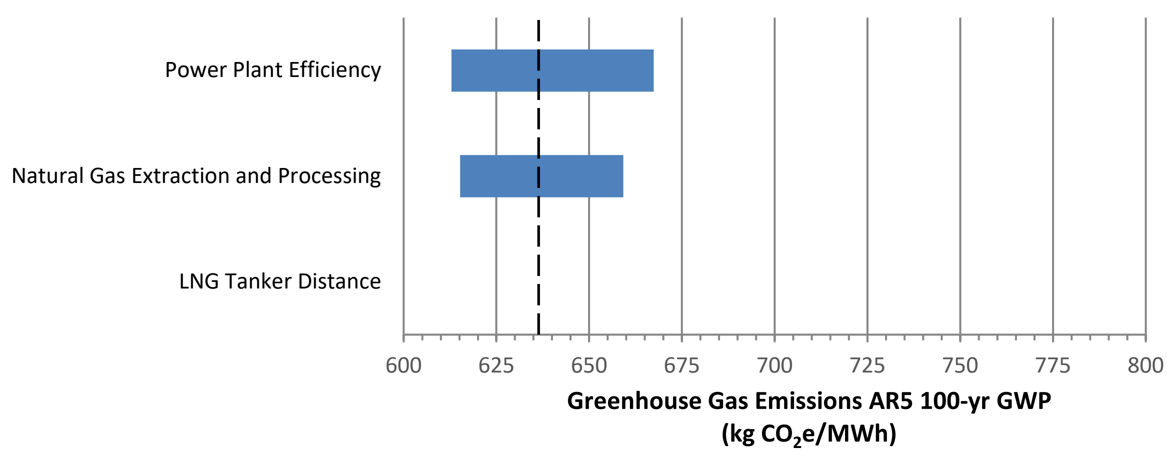


Exhibit 6-12. Uncertainty Tornado LNG – Oran, Algeria to Rotterdam, Netherlands

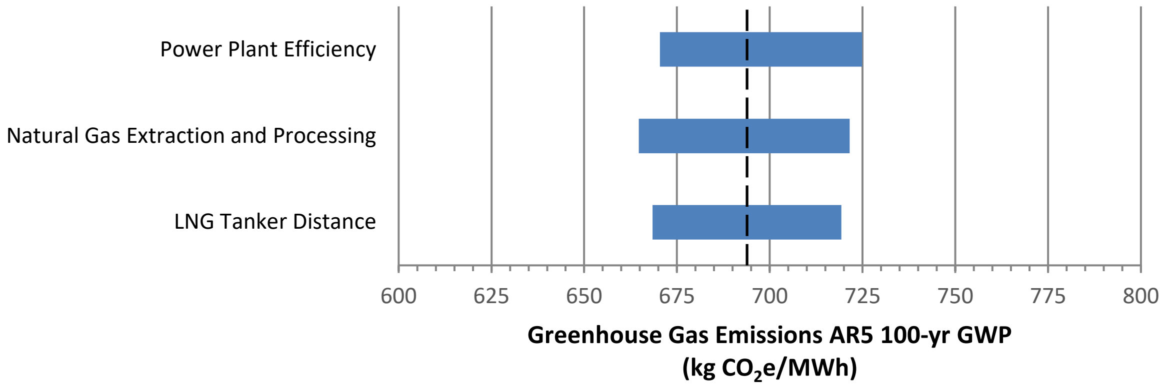


Exhibit 6-13. Uncertainty Tornado LNG – U.S. LNG (New Orleans) to Shanghai, China

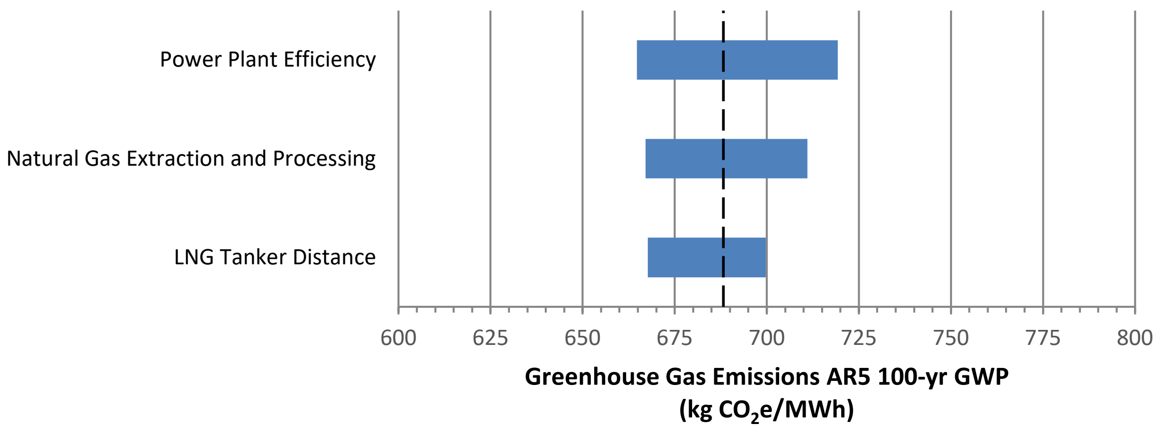


Exhibit 6-14. Uncertainty Tornado LNG – Darwin, Australia to Shanghai, China

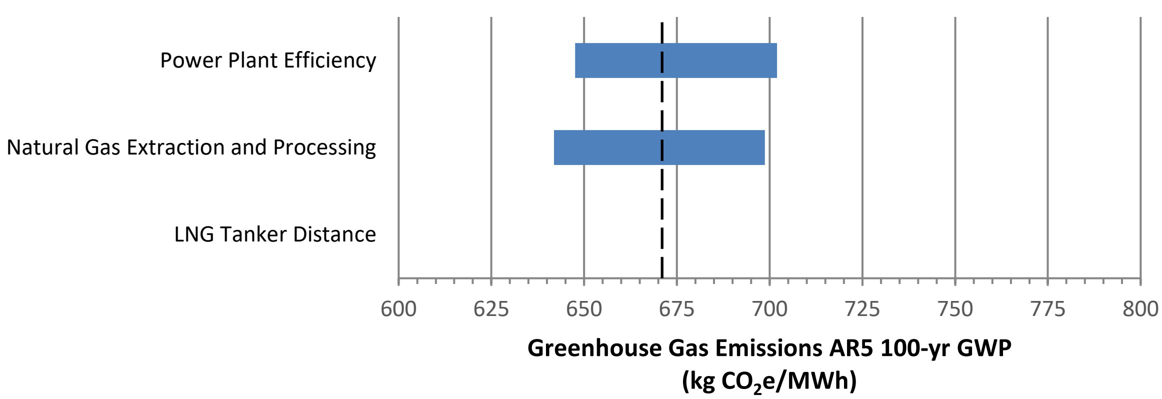


Exhibit 6-15. Uncertainty Tornado Russian NG – Yamal, Russia to Rotterdam, Netherlands

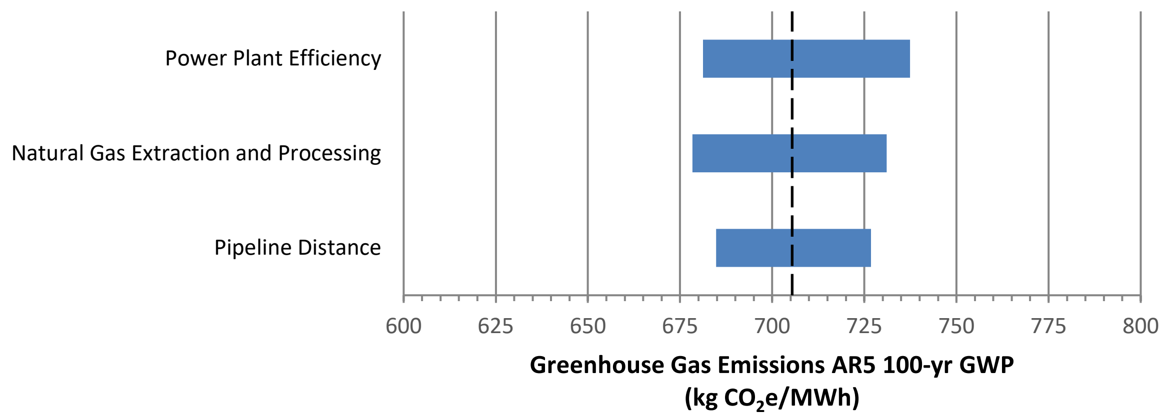


Exhibit 6-16. Uncertainty Tornado Russian NG – Yamal, Russia to Shanghai, China

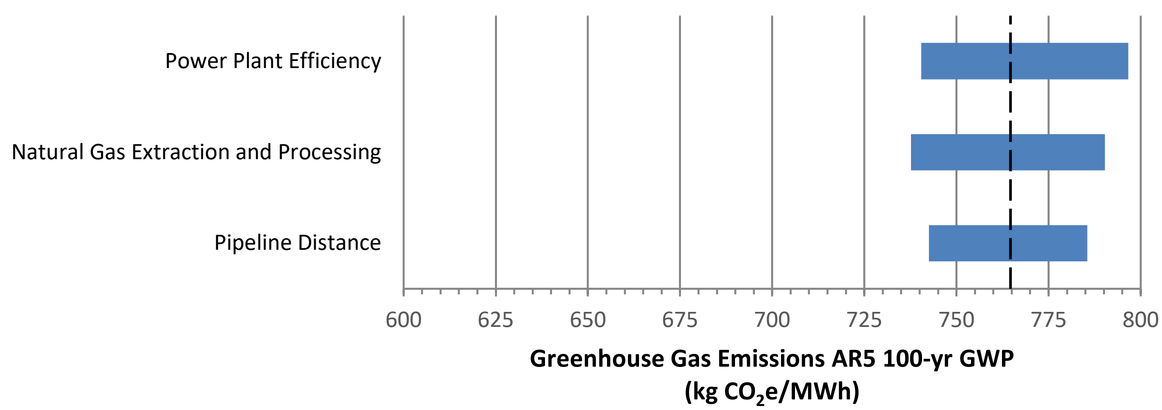
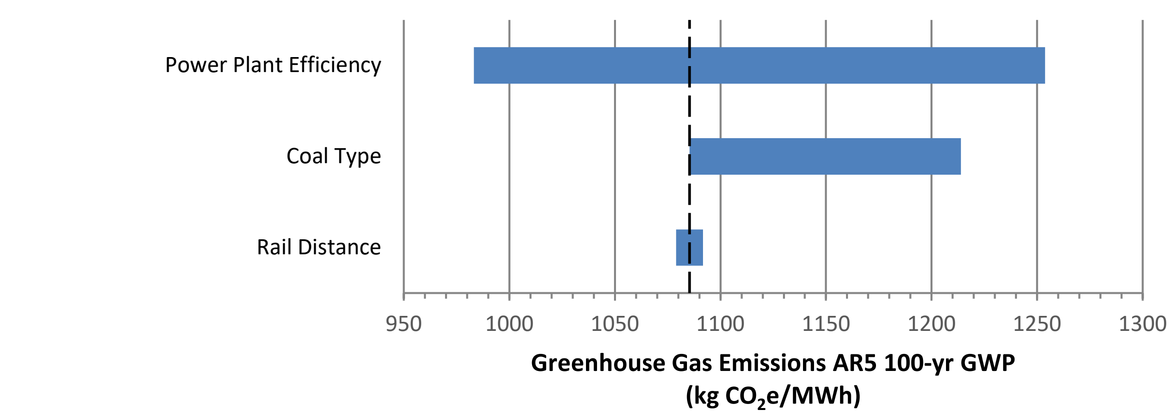


Exhibit 6-17. Uncertainty Tornado Coal – Europe and Asia Regional Production



7 Summary and Study Limitations

This analysis has determined that the use of U.S. LNG exports for power production in European and Asian markets will not increase GHG emissions from a life cycle perspective, when compared to regional coal extraction and consumption for power production.

The results show that for all 100-yr time horizon scenarios the generation of power from natural gas has lower life cycle GHG emissions than power generation from regional coal. The European and Asian coal scenarios are identical because the same parameter ranges are used for both. The interpretation of the 20-yr natural gas scenarios is more complex due to the tradeoff between upstream GHG intensities and end use efficiencies. Specific conclusions are as follows:

- On a 20-yr GWP time horizon, the Russian natural gas and Algeria LNG scenarios have overlapping error bars with the regional coal scenarios.
- The U.S. LNG to Europe and Asia and Australia LNG scenario do not overlap the regional coal scenario on a 20-yr time horizon.

On both time-horizons, uncertainty in the natural gas supply chain obfuscates upstream stage-wise comparisons among scenarios, but confidence in scenario-specific transport distances is a key differentiator.

Study limitations are due to challenges with data availability and LNG market dynamics:

- The upstream data for coal and natural gas are U.S.-based models that were adapted for foreign natural gas and coal production as well as power generation.
- The specific LNG export/import locations used in this study were chosen to represent an estimate for a region (e.g., New Orleans as U.S. Gulf Coast). Specific locations were required to allow for the estimation of LNG transport distances and do not imply the likelihood that LNG export or import will occur from that exact location. The same assumptions hold true for the Russian natural gas cases.
- Power plant efficiencies in destination countries are adapted from work based on U.S. power plants.

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APPENDIX A: LIFE CYCLE RESULTS

Exhibit A-1. Life Cycle GHG Emissions for Natural Gas and Coal Power in Europe (IPCC AR5 GWP) (kg CO_2e/MWh)

Life Cycle Process	100-yr GWP				20-yr GWP			
	New Orleans to Rotterdam, Netherlands	Oran, Algeria to Rotterdam, Netherlands	Yamal, Russia to Rotterdam, Netherlands	European Regional Coal	New Orleans to Rotterdam, Netherlands	Oran, Algeria to Rotterdam, Netherlands	Yamal, Russia to Rotterdam, Netherlands	European Regional Coal
Natural Gas/Coal Extraction	21	66	61	9	31	145	134	14
Natural Gas Gathering & Boosting	49	48	45	0	72	74	69	0
Natural Gas Processing	18	18	17	0	25	25	23	0
Domestic Pipeline Transport	61	61	166	0	83	84	373	0
Liquefaction	38	39	0	0	53	39	0	0
Tanker/Rail Transport	28	40	0	11	32	75	0	11
LNG Regasification	4	4	0	0	5	5	0	0
Power Plant Operations	416	416	416	1,063	416	416	416	1,063
Electricity T&D	2	2	2	2	1	1	1	1
Total (Expected)	636	694	705	1,085	719	865	1,016	1,090
Low	615	644	668	969	701	811	941	973
High	709	750	778	1,408	825	982	1,183	1,602

Exhibit A-2. Life Cycle GHG Emissions for Natural Gas and Coal Power in Asia (IPCC AR5 GWP) (kg CO_2e/MWh)

Life Cycle Process	100-yr GWP				20-yr GWP			
	New Orleans to Shanghai, China	Darwin, Australia to Shanghai, China	Yamal, Russia to Shanghai, China	Chinese Regional Coal	New Orleans to Shanghai, China	Darwin, Australia to Shanghai, China	Yamal, Russia to Shanghai, China	Chinese Regional Coal
Natural Gas/Coal Extraction	21	66	63	9	32	143	137	14
Natural Gas Gathering & Boosting	50	48	46	0	73	74	70	0
Natural Gas Processing	18	18	17	0	25	25	24	0
Domestic Pipeline Transport	60	61	222	0	85	83	499	0
Liquefaction	41	38	0	0	54	53	0	0
Tanker/Rail Transport	76	19	0	11	91	22	0	11
LNG Regasification	4	4	0	0	5	5	0	0
Power Plant Operations	416	416	416	1,063	416	416	416	1,063
Electricity T&D	2	2	2	2	1	1	1	1
Total (Expected)	688	671	765	1,085	783	822	1,148	1,090
Low	663	644	712	969	757	782	999	973
High	763	750	833	1,408	888	955	1,267	1,602

APPENDIX B: UNIT PROCESS DESCRIPTIONS

B.1 LIQUEFACTION

The pre-treatment, liquefaction and storage unit process (UP) accounts for the pre-treatment of the input pipeline quality gas, liquefaction of the pre-treated gas, and on-site temporary storage of LNG before it is loaded onto an ocean tanker. The pre-treatment processes include:

- Acid gas removal (AGR): removal of CO_2 and H_2S from the pipeline feed gas, to avoid freezing and plugging in downstream units. (~7,050 ppmv (EPA, 1996) to ~50 ppmv CO_2 (Mallapragada et al., 2018))
- Molecular sieve dehydration: removal of water to avoid freeze-up and unplanned shut downs, costly repairs and hazardous working conditions (ensure <0.5 ppmv water (Mallapragada et al., 2018))
- Heavy hydrocarbon (HHC) removal: to protect the main heat exchanger from freezing and plugging. This can be done by either adsorption or cryogenic distillation (~75 ppmv (EPA, 1996) to <10 ppmv C5+ (Smith & Doong, 2016))

The liquefaction facilities in the U.S. predominantly employ two technologies, Propane Pre-cooled Mixed Refrigerant (C3MR) process and Optimized Cascade process. This model represents the C3MR technology in combination with different pre-treatment technologies, represented through four different scenarios. The energy requirement for all scenarios is estimated based on literature (Mallapragada et al., 2018). Based on the publicly available data on plant export capacities (EIA, 2017) and ship capacity assumptions (IGU, 2017), the residence time of LNG on site is estimated, which is treated as the LNG storage time on site. This value is estimated to be between 1.33 days to 1.60 days. During storage, boil-off gas (BOG) is generated at an estimated boil-off rate (BOR) of 0.02% to 0.1% (Dobrota et al., 2013). It is assumed that the BOG generated during storage is re-liquefied, which then enters back into the supply-chain. Literature suggests that the temporary onsite storage unit does not require energy to maintain the LNG in its liquid stage because it uses the concept of auto-refrigeration. The pre-treatment and liquefaction energy requirement is assumed to be met through combusting a parasitic stream of NG as it leaves the pre-treatment facility and before it enters the liquefaction facility. The functional unit of this unit process is the mass of LNG that is stored after being treated and liquefied.

B.2 LOADING AND UNLOADING

The loading and unloading UPs represent the process of loading LNG from the liquefaction facility onto an ocean tanker and the process of unloading the LNG from the ocean tanker into a regasification storage facility after transportation. These UPs model the ship capacity to be in the range of 150,000 m^3 to 180,000 m^3 (IGU, 2017). The BOG generated during loading and unloading is assumed to be re-liquefied and directed back into the supply chain, so the net loss of LNG during loading and unloading is zero. Based on literature, a standard loading/unloading rate of 10,000-12,000 m^3/hour and a BOR of 20,000 kg/hour is modeled (Dobrota et al., 2013).

In any journey only 98% of the total ship capacity is utilized (Hasan et al., 2009). During loading, 0.15% of the volume is still occupied by the heel leftover from the previous ballast voyage, hence 97.85% [98%-0.15%] is to be loaded. During unloading, 2.5% of the capacity is to be left behind as heel for the ballast voyage (Cheniere Energy, 2018). The average time at sea for the scenarios investigated in this analysis is 22.67 days (Sea-Distances.org, 2016) and modeling the BOR to be 0.1 percent volume/day during transportation (IGU, 2017), it is calculated that approximately 93.23% [98%-2.5%-0.1*22.67] of the ship will have to be unloaded on arrival at the port. A sensitivity analysis was performed on this assumption. The same calculation was performed for the shortest shipping distance and the longest shipping distance. Because there are no losses during loading and unloading (all BOG is captured and re-liquified), no change in result was observed. Thus, the 22.67 average days at sea for all scenarios was a simplification used in the unloading unit process only to calculate the energy requirements of unloading. The ocean transport unit process accounts for the true number of days at sea, and thus calculates the appropriate losses that occur at sea. The loading/unloading equipment is modeled as diesel based and the total diesel consumption is estimated by back-calculation from a literature based CO_2 emission data point (Pace Global, 2015). It is assumed that the BOG re-liquefaction compressor operates on purchased grid mix electricity. Compressor specifications from literature are used to estimate the energy requirement to re-liquify 1 kg of BOG (Li & Wen, 2016). The functional unit of this process is the mass of LNG loaded or unloaded from the ocean tanker.

B.3 Ocean Transport

The ocean transport UP accounts for the operation of a tanker to transport LNG from a given export country to the import country. The UP is based on specifications for the Wartsila 50DF engine (Wärtsilä, 2018), engine driving propeller, variable speed (ME). The fuel oil and fuel gas consumption rates are equal for all 5 engine configurations identified by Wartsila, so a specific configuration was not chosen to be represented. The model calculates the laden and ballast voyage time based on ship speed and voyage length. A 2.5% volume heel is modeled for the ballast voyage (Cheniere Energy, 2018). BOG from the storage of LNG is compressed and used for fuel, with Ultra Low Sulfur Diesel (ULSD) used as the supplementary fuel. The amount of BOG generated during the laden voyage is dependent on the length of the journey (a boil-off rate of 0.1% volume/day is used (IGU, 2017)). The BOG generated during the ballast journey is taken to be 95% of the heel (i.e. most of the heel is used as energy on the return voyage, leaving only enough to keep the ship cold and ready to load). It is assumed that 100% of the available capacity is loaded onto the ship, and that 98% of the tanker capacity is usable capacity (98% before the heel)(Hasan et al., 2009). The BOG is compressed to 0.6 megapascals (MPa) gauge pressure before it is sent for combustion, as specified by the engine requirements in the product manual (Wärtsilä, 2018). The tanker is assumed to operate 24 hours per day during ocean transport. Full cruise fuel use is calculated using 100% load factors, ramp up/ramp down 75% load factor, and idling/maneuvering 50% load factor (Wärtsilä, 2018). While it is possible for BOG to be generated at any time on the ship, due to the transient conditions and uncertainty in BOR, model limitations do not allow for the estimate of these volumes over short time frames. For simplification, BOG is assumed to be generated only during ramp up/down and full cruise, and combusted only when the ship is at full cruise. Diesel is assumed to be the only fuel used during non-full cruise operations. Roundtrip travel is accounted for in this unit process (i.e., emissions reported represent total emissions generated during the laden and ballast voyage). The following assumptions were made about the ship's operations: the ship is idling during loading and unloading times, the ship spends one day in maneuvering mode, and the ship spends one day ramping up and one day ramping down for both the laden and ballast journey (4 days total). The distance traveled during ramping up and down counts towards the total distance traveled for the journey. Distance traveled during maneuvering and idling is assumed to be negligible. Travel distances for different scenarios were calculated using SEA-DISTANCES (Sea-Distances.org, 2016). The functional unit for this unit process is taken to be the mass of LNG delivered to the regasification terminal (import terminal). This is taken to be 98% of the ship capacity, minus BOG generation during the laden voyage, minus the 2.5% volume heel that will be left on the ship for the ballast voyage.

B.4 REGASIFICATION

The regasification UP accounts for the operation of a regasification terminal located in either Europe or Asia. The UP is based on Open Rack Vaporization (ORV) technology, which is utilized in ~100% of Asian and ~60% of European regasification terminals (Agarwal et al., 2017). After unloading from the ship, the LNG is placed in temporary storage for between 1.33 and 1.60 days (EIA, 2017; IGU, 2017). The BOG generated during temporary storage is assumed to be captured and re-liquefied before being sent through the ORV. The BOR is 0.02% of storage volume/day (Dobrota et al., 2013). The required energy for regasification is assumed to be sourced from grid mix electricity. In ORV, the LNG is passed through a heat exchanger with sea water. Emissions results account for emissions from fugitives. Combustion emissions are accounted for in a separate combustion UP. The functional unit of this unit process is the mass of LNG that is regasified.

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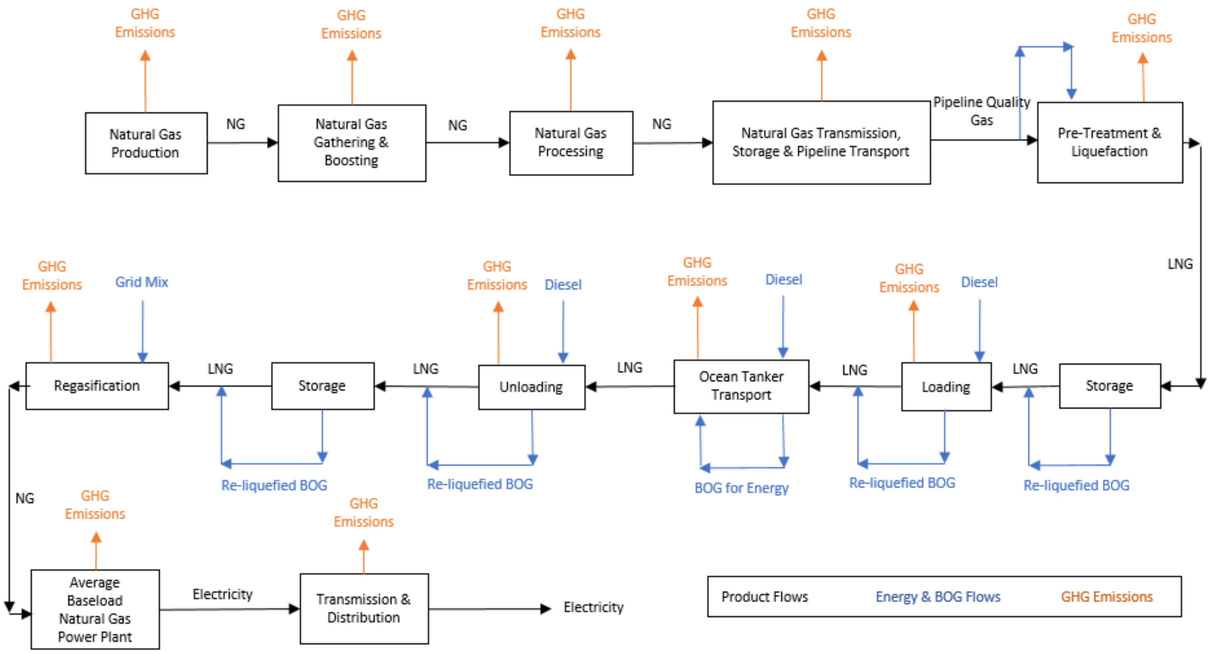
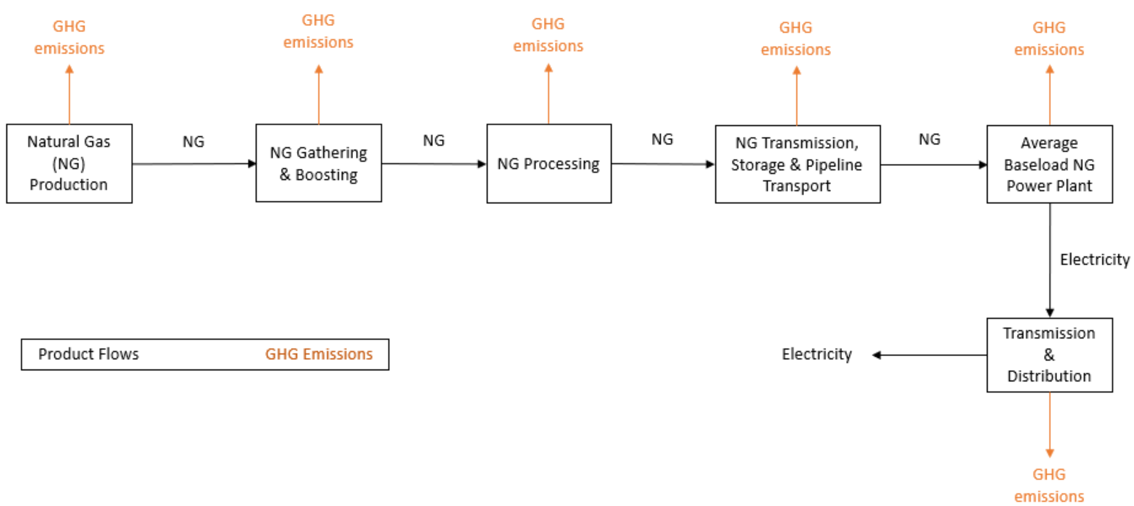
Appendix C: Flow Diagrams

Note: The energy flows shown in the following flow diagrams represent energy flows specifically modeled in the LNG analysis. Other unit processes require energy, but have the energy requirements accounted for within the unit process and thus contain the GHGs from energy use.

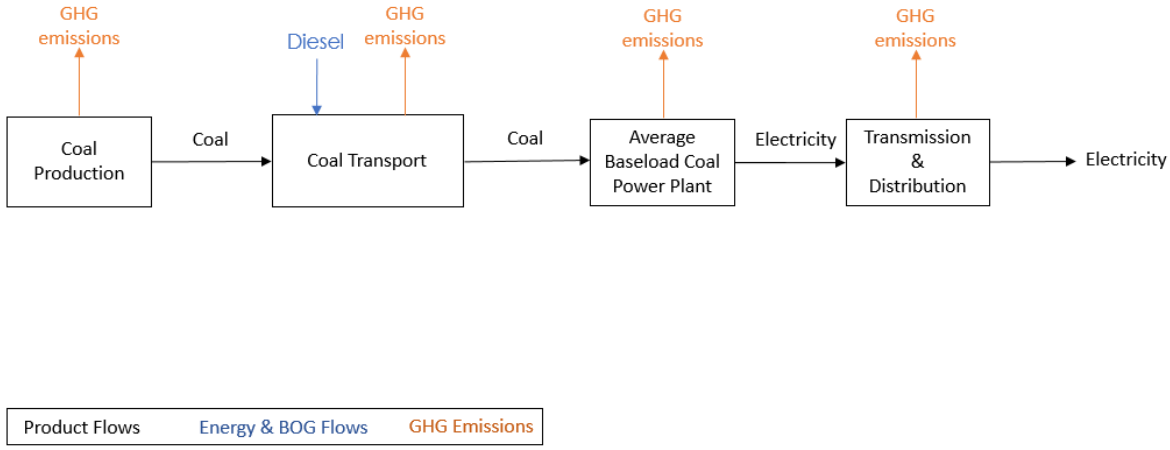
C.1 U.S./Regional Liquefied Natural Gas



C.2 Russian Natural Gas



C.3 Regional Coal



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$8.29B	$2.69B	$2.69B	-1.47
WORLD RNK 1 / 68; RNK 6 / 1194	CHINA	CHINA	RNK 945 / 1025

2022 IMPORTS	2022 ORIGIN	2021 - 2022 FASTEST GROWING ORIGIN	2022 ECONOMIC COMPLEXITY OF INDONESIA
$254K	$152K	$152K	-0.012
WORLD RNK 47 / 114; RNK 1135 / 1206	INDIA	INDIA	RNK 67 / 133

LATEST TRENDS HISTORICAL DATA POTENTIAL EXPORTS

About

Exports In 2022, Indonesia exported $8.29B in Lignite, making it the 1st largest exporter of Lignite in the world. At the same year, Lignite was the 6th most exported product in Indonesia. The main destination of Lignite exports from Indonesia are: China ($7.94B), South Korea ($95.9M), Pakistan ($66.9M), Singapore ($58.9M), and Spain ($22.2M).

The fastest growing export markets for Lignite of Indonesia between 2021 and 2022 were China ($2.69B), South Korea ($95.9M), and Pakistan ($53.2M).

Imports In 2018, Indonesia imported $254k in Lignite, becoming the 47th largest importer of Lignite in the world. At the same year, Lignite was the 1135th most imported product in Indonesia. Indonesia imports Lignite primarily from: India ($204k), United States ($36k), Singapore ($7.36k), Japan ($6.2k), and China ($150).

The fastest growing import markets in Lignite for Indonesia between 2021 and 2022 were India ($152k), Japan ($6.2k), and United States ($3.39k).

COMPANIES In 2023, leading companies such as Cinmar (1) were at the forefront of shipping Lignite from Indonesia to the United States.

LATEST TRENDS

MAY 2024

Subnational Monthly Trade

VIEW: LinePlot | StackedArea

FLOW: Exports | Imports

Y-AXIS SCALE: Linear | Log

VALUE: TRADE VALUE

For a full breakdown of trade patterns, visit the

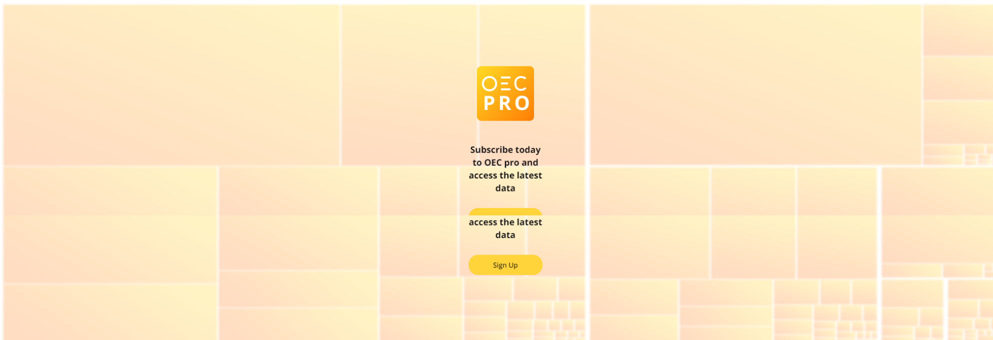
VALUE: TRADE VALUE

For a full breakdown of trade patterns, visit the trend explorer or the product in country profile.

The following visualization shows the latest trends on Lignite. Countries are shown based on data availability.

*** Using January 2020 exchange rates when trade data is reported in local currency.**

Explore Latest Trends



HISTORICAL DATA

Trade Balance

COLOR: Trade Value | Growth | Growth (%)

YEAR: 2022

EXPORTS (2022) $8.29B

IMPORTS (2022) $254k

NET TRADE (2022) $8.28B

In 2022, Indonesia exported $8.29B in Lignite. The main destinations of Indonesia exports on Lignite were China ($7.94B), South Korea ($95.9M), Pakistan ($66.9M), Singapore ($58.9M), and Spain ($22.2M).

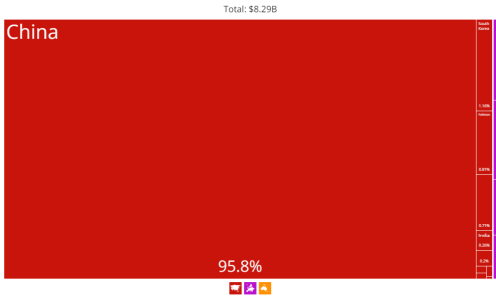
In 2022, Indonesia imported $254k in Lignite, mainly from India ($204k), United States ($36k), Singapore ($7.36k), Japan ($6.2k), and China ($150).

Explore Visualizations

Data from BACI HS6 REV. 1992 (1995 - 2022).

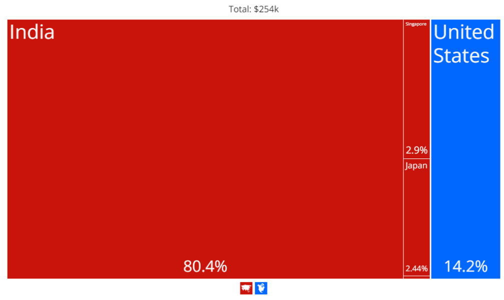
Export Destinations (2022)

Total: $8.29B



Import Origins (2022)

Total: $254k



Market Growth

FLOW: Exports | Imports

STARTING: 2021

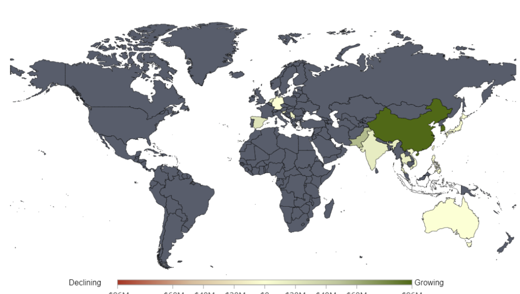
ENDING: 2022

THE FASTEST GROWING LIGNITE EXPORT MARKETS FOR INDONESIA WERE (2021 - 2022):	THE FASTEST DECLINING MARKETS FOR THE EXPORT OF LIGNITE BY INDONESIA WERE (2021 - 2022):
China $2.69B (51.3%)	Chinese Taipei -$3.95M (-47.3%)
South Korea $95.9M (1%)	Slovenia -$2.89M (-19.2%)
Pakistan $53.2M (391%)	Hong Kong -$2.47M (-100%)

Explore Visualizations

Data from BACI HS6 REV. 1992 (1995 - 2022),. and BACI HS6 REV. 1992 (1995 - 2022).

Change in Exports by Market (2021 - 2022)



Market Concentration

VIEW: LinePlot | StackedArea

FLOW: Export | Import

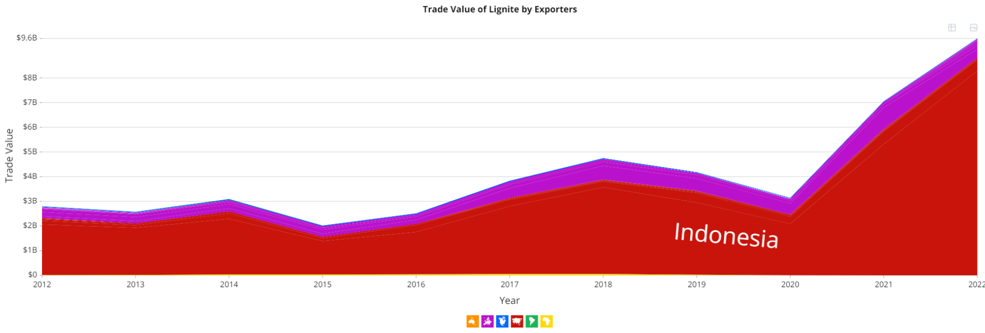
TYPE: Value | Share

IN 2022, INDONESIA'S MAIN EXPORTING COMPETITORS IN LIGNITE WERE:	IN 2022, INDONESIA'S MAIN IMPORTING COMPETITORS IN LIGNITE WERE:
Philippines $450M	China $8.75B; Serbia $141M
Russia $348M	South Korea $96M

Explore Visualizations

Data from BACI HS6 REV. 1992 (1995 - 2022).

Trade Value of Lignite by Exporters



POTENTIAL EXPORTS

Potential Exports

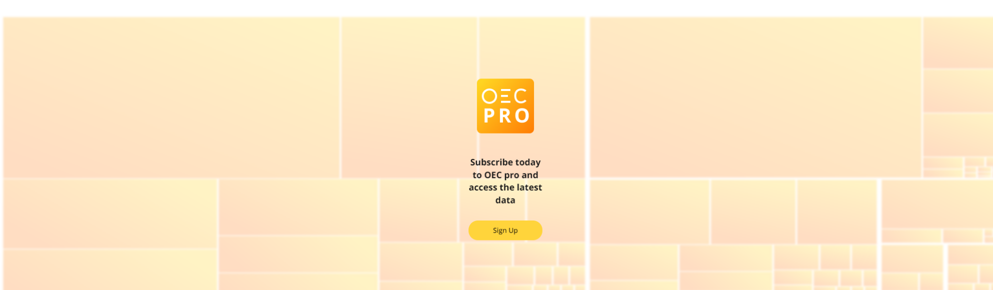
FLOW: Exports | Imports

VIEW: World Map | Bar Chart

TOP EXPORT POTENTIAL	TOP IMPORT POTENTIAL
India + $9.25M	United States + $12K

Lignite's highest export potential is India. With an export gap of $9.25M. Lignite's highest import potential is United States with an import gap of $12k.

See methodology.



Keep Exploring

Energy Sustainable Markets Regulatory Oversight Governance Grid & Infrastructure

China's new coal plants set to become a costly second fiddle to renewables

By David Stanway and Muyu Xu

March 22, 20237:08 PM EDTUpdated a year ago

[1/2]A worker walks past coal piles at a coal coking plant in Yuncheng, Shanxi province, China January 31, 2018. REUTERS/William Hong/File Photo *Purchase Licensing Rights*

SINGAPORE, March 23 (Reuters) - China's plans for some 100 new coal-fired power plants to back up wind and solar capacity have sparked warnings that the world's second-biggest economy is likely to end up lumbered with even more loss-making power assets.

Analysts question the logic of policies that intend to reduce the role of the dirtiest fossil fuel but at the same time require more coal-fired power plants to be built - especially given that only a small number of older plants are typically retired each year.

The plans also highlight how local government interests have impeded the development of an effective nationwide power market that would allow surplus power to be delivered to regions that need it, they add.

"The reality is that China has more coal power capacity than it needs," said Zhang Shuwei, director at Draworld Energy Research Centre. "It doesn't make sense to give more incentives for more coal-fired power investments."

China is the world's largest and fastest-growing producer of renewable energy, which is expected to account for a third of all power supplied to its grid by 2025, up from 28.8% in 2020.

But it was scarred by a record drought last year that slashed hydropower output, forcing factories throughout the southwest to shut down and raising concerns that power shortages could undermine its post-COVID economic recovery. The experience increased its determination not to be too reliant on the intermittent nature of wind and solar power and has made China the only major economy building new coal-powered plants.

The construction of 106 gigawatts of coal-fired power was approved last year - four times more than in 2021 and the highest amount since 2015, according to research published last month by the Centre for Research on Energy and Clean Air (CREA) and Global Energy Monitor (GEM).

That's equivalent to about a hundred large coal-fired plants and enough to supply the whole of Britain. At least 50 GW of that capacity began construction in 2022, the report said.

China's National Development and Reform Commission (NDRC) has also flagged that at least 200 GW of coal capacity is expected to be deployed to support renewable power.

China's big jump in coal power approvals has sparked fears that there will be backsliding on its climate goals.

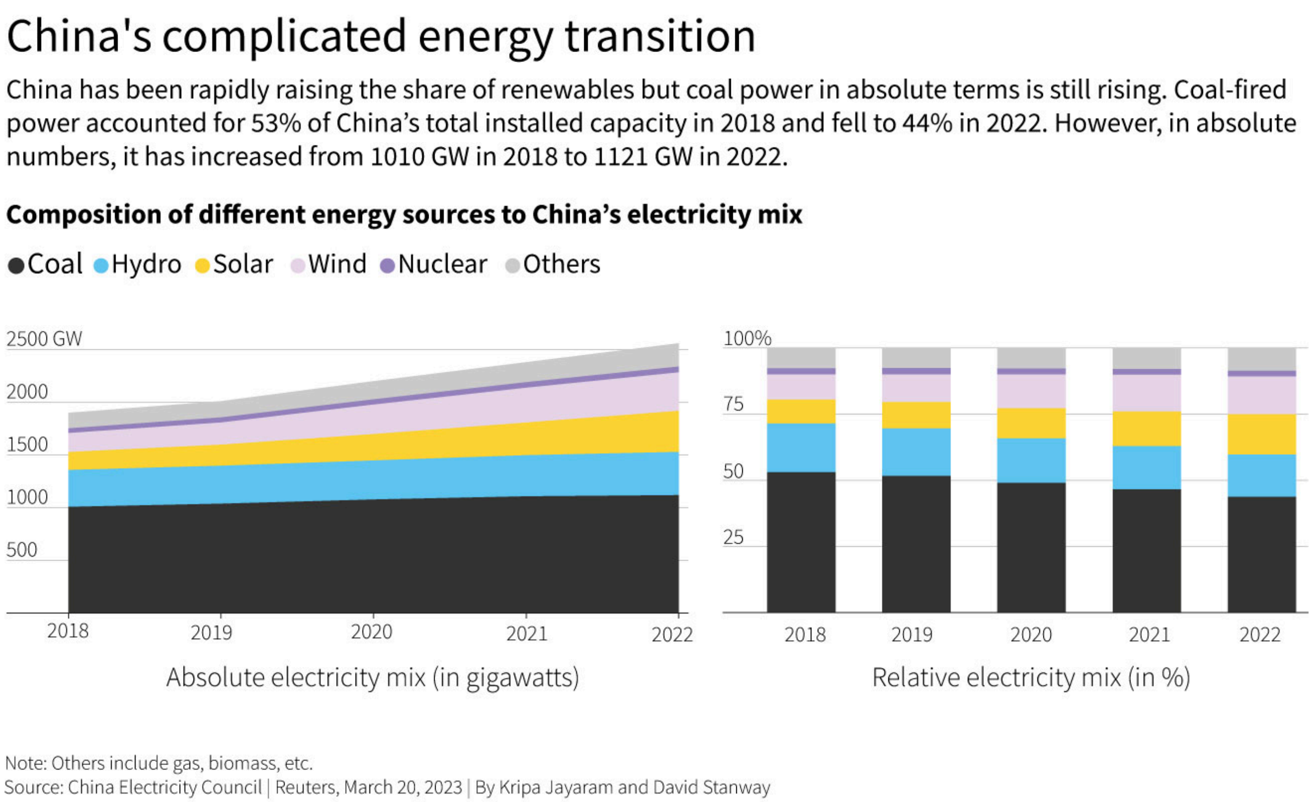
The CREA-GEM report says it won't necessarily mean the sector's coal use or carbon emissions will climb. But for China to make good on its goals - namely a peak in emissions before 2030 and becoming carbon neutral by 2060 - the loss-making sector's plant utilisation rates will probably have to slide further.

The NDRC's National Energy Administration did not respond to a request for comment.

LOSS-MAKING, UNDER-UTILISED

Coal accounted for 58.4% of China's total power generation last year, but high prices have meant many plants have suffered losses for years. More than half of the country's large coal power firms were loss-making in the first half of 2022, according to the China Electricity Council.

And even though many plants were producing more last year to compensate for the decline in hydropower output, the average utilisation rate inched down to 52.4%.



Share of coal in China's energy mix

Analysts note existing coal plants could provide sufficient backup for renewables if they were plugged into a nationwide market, but China's power sector remains fragmented.

Historically, power plants have been built to support local industry and local GDP growth rather than national power supplies, with provinces reluctant to rely on other provinces for their needs.

Power plants are also not motivated to maximise power output because prices are fixed for residential users while price hikes for business users are limited to 20% of the fixed tariff.

The NDRC has been working on capacity payment mechanisms that compensate coal power plants for the decline in earnings as they adjust to their new role as backup suppliers.

The drought-prone southwestern province of Yunnan, which depends on hydropower for most of its electricity, recently set up a capacity market in which coal plants are paid to be available to fulfil supply shortfalls. Other regions are also involved in pilot schemes.

"I think the expectation of these capacity payments is one motivation for coal power groups to pursue new projects despite the fact that power generation from coal is unprofitable at the moment," said Lauri Myllyvirta, lead analyst at CREA.

It is also unclear who will be paying for the subsidies, said Zhang at Draworld Energy, adding it would be "terrible news" if the costs were to be shouldered by renewable power generators.

Yunnan's provincial planning agency did not respond to a request for comment.

Instead of building expensive new plants, China could instead encourage existing plants with surplus capacity to deliver electricity to regions that need it the most, said Matt Gray, chief executive of think tank TransitionZero.

"It would be far cheaper... to incentivise provincial trading than incentivising new loss-making coal," he said.

Reporting by David Stanway; Additional reporting by Muyu Xu; Editing by Edwina Gibbs

China approved equivalent of two new coal plants a week in 2022, report finds

By Jessie Yeung, CNN

3 minute read Published 2:57 AM EST, Mon February 27, 2023

A bulldozer pushes coal onto a conveyor belt at the Jiangyou Power Station on January 28, 2022 in China's Sichuan province. Liu Zhongjun/China News Service/Getty Imsges/File

Hong Kong CNN — China is surging ahead with coal, a new report shows, rapidly approving and building new power plants despite its own promises to cut back on carbon as the world plunges ever deeper into the climate crisis.

Last year, the country approved the highest number of new coal-fired power plants since 2015, according to the report, released Monday by the Center for Research on Energy and Clean Air (CREA) and the Global Energy Monitor (GEM).

“China continues to be the glaring exception to the ongoing global decline in coal plant development,” said Flora Champenois, a research analyst at GEM.

“The speed at which projects progressed through permitting to construction in 2022 was extraordinary, with many projects sprouting up, gaining permits, obtaining financing and breaking ground apparently in a matter of months,” she added.

China's emissions are more than double those of the United States, and though the country's leaders have previously vowed to cut back on carbon, its reliance on coal poses a significant challenge.

China turns back to coal as record heatwave causes power shortages

Throughout 2022, China granted permits for 106 gigawatts of capacity across 82 sites, quadruple the capacity approved in 2021 and equal to starting two large coal power plants each week, said the report.

Last year, China experienced its worst heat wave and drought in six decades, dealing a blow to hydropower-reliant provinces -— and prompting authorities to turn toward coal instead.

To ease the power crunch, coal plants boosted their output, with daily thermal coal consumption hitting a record high in August.

2021 wasn't much better. Though Beijing had initially shut down hundreds of coal mines and pushed the remaining ones to curtail production, nationwide power shortages led the government to order mines to "produce as much coal as possible."

That push doesn't appear to be ending anytime soon, with the report authors warning that even China's simultaneous expansion in renewable energy won't be enough to offset the impact.

China added a record 125 gigawatts of solar and wind capacity last year, making up 2% of the country's electricity demand. And though that target is even higher this year, "even this increase won't be sufficient to supply all of the demand growth without increasing power generation from fossil fuels," said the report.

China mined a record amount of coal in 2021. It might produce even more this year

It added that for China to truly cut down on carbon emissions, it needs to start phasing out its "vast coal power plant fleet" rather than continue growing it. Besides the plants' environmental impact, their "politically influential owners … have an interest in protecting their assets," said the report.

Carbon neutral goal

China and the United States are the world's two biggest carbon emitters, with China's emissions tripling over the past three decades, one report found in 2021.

And though Chinese leader Xi Jinping had declared in 2020 that the country would become carbon neutral by 2060, activists and experts have said the government isn't taking swift or decisive enough action.

For instance, though China released a new plan in 2021 to cut its reliance on fossil fuels, it did not announce an updated emissions target. Later that year, the emission-cutting plan it submitted to the United Nations drew disappointment from other world leaders who had hoped for significantly higher pledges and an accelerated decarbonization timeline.

Xi himself softened his tone toward zero-carbon in the face of power outages, factory closures and compromised supply chains, saying early last year that "carbon peak and carbon neutrality cannot be realized overnight."

The country's climate efforts have also been hampered by geopolitics, with China suspending climate talks with the United States last year in response to US House Speaker Nancy Pelosi's trip to Taiwan — dismaying activists, who say the two countries' cooperation is crucial if the world is to avert climate catastrophe.

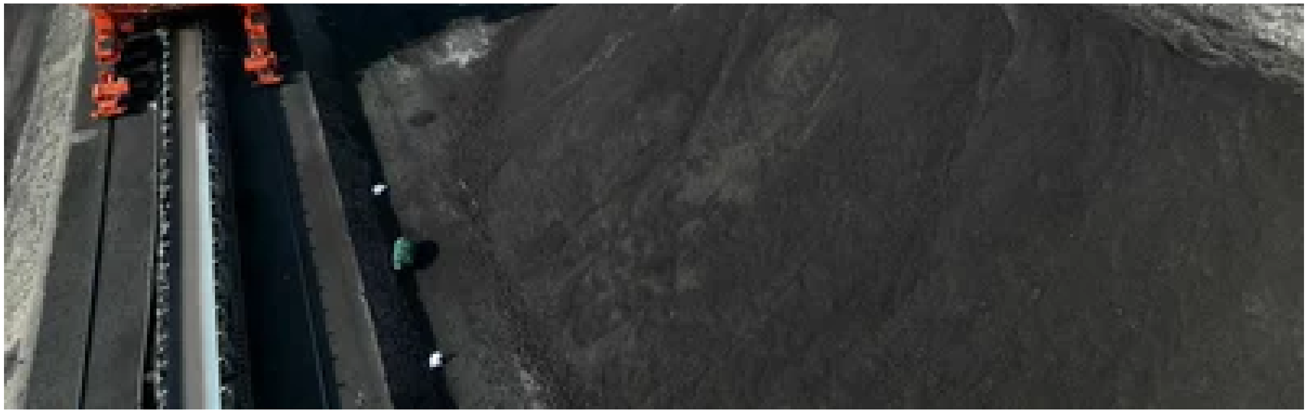
Negotiations restarted months later at the UN's COP27 summit in Egypt.

China is building six times more new coal plants than other countries, report finds

MARCH 2, 20236:00 AM ET

By Julia Simon

3-Minute Listen PLAYLIST



A new report finds that last year China permitted the equivalent of two coal plants per week. China's renewable sector is also booming.
VCG/VCG via Getty Images

China permitted more coal power plants last year than any time in the last seven years, according to a new report released this week. It's the equivalent of about two new coal power plants per week. The report by energy data organizations Global Energy Monitor and the Centre for Research on Energy and Clean Air finds the country quadrupled the amount of new coal power approvals in 2022 compared to 2021.

That's despite the fact that much of the world is getting off coal, says Flora Champenois, coal research analyst at Global Energy Monitor and one of the co-authors of the report.

"Everybody else is moving away from coal and China seems to be stepping on the gas," she says. "We saw that China has six times as much plants starting construction as the rest of the world combined."

What's driving the new permitting of Chinese coal plants?

The report authors found the growth of new coal plant permitting appears to be a response to ongoing drought and last summer's historic heat wave, which scientists say was made more likely because of climate change. The heat wave increased demand for air conditioning and led to problems with the grid. The heat and drought led rivers to dry up, including some parts of the Yangtze, and meant less hydropower.

"We're seeing sort of this knee-jerk response of building a lot more coal plants to address that," says

Champenois.

High prices for liquified natural gas due to the war in Ukraine also led at least one province to turn to coal, says Aiqun Yu, co-author of the report and senior researcher at Global Energy Monitor.

New coal plant approvals accelerated last summer as China saw historic heat waves that increased demand for air conditioning. The heat and an ongoing drought meant rivers dried up, including part of the Yangtze. China's grid struggled as hydropower went offline.

STR/AFP via Getty Images

Why is China building new coal plants while also increasing renewables?

China leads the world in constructing new solar and new wind, while also building more coal plants than any other country, the report finds.

There are government and industry arguments that the coal plants will be used as backup support for renewables and during periods of intense electricity demand, like heat waves, says Ryna Cui, the assistant research director at the Center for Global Sustainability at the University of Maryland School of Public Policy. "That's being used as an excuse for new projects," Cui says.

Last year's boom in new coal didn't come out of nowhere, says Yu, who notes that the domestic coal industry has long pushed the message that coal is a reliable form of energy security.

"When the energy crisis happened, when energy security is a big concern, the country just seeks solutions from coal by default," Yu says.

Champenois says the surge in permits last year could be China's coal industry seizing upon a last chance to get financing for new coal plants, which are increasingly uneconomical compared to renewables.

"We see it as a door opening, maybe one for one last time," she says. "If you're a power company, you're gonna try to put your foot in that door."

How does permitting new coal plants affect China's goals to reduce emissions?

China is the world's biggest emitter of fossil fuels and has pledged for its emissions to peak by 2030. But there are questions over how high that peak will get and how soon that peak will come, says Champenois.

The International Energy Agency recently reaffirmed there must be "no new development of unabated coal-fired power plants" to keep temperatures less than 1.5 degrees Celsius and avoid the worst effects of climate change.

It's too early to know how much the plants will run and how they will impact China's emissions, says Lauri Myllyvirta, lead analyst at the Centre for Research on Energy and Clean Air and one of the report's co-authors.

"The challenge though is going to be that all of these power plants have owners that are interested in making as much money as possible out of running them," he says.

What possible solutions may help speed China's green transition?

Myllyvirta says a lot of solutions come down to fixing the country's electric grid, including making the grid more efficient, and making it easier to share energy across China's regions if there are power shortages.

Champenois says shifting coal investments into renewables and storage would be the smart decision for China. That way they won't have "stranded assets" she says, investments that will end up losing money.

Appendix G
Relative Emissions

Appendix G

LNG exports can have significant environmental benefits as natural gas is cleaner burning than other fossil fuels. For example, the NETL's Life Cycle Greenhouse Gas study ("GHG") noted that under most scenarios analyzed in the report, "generation of power from imported natural gas [into both Europe and Asia] has lower life cycle GHG. "Perspective on Exporting Liquefied Natural Gas from the U.S.: 2019 Update" ("2019 GHG Report").[1] The 2019 GHG Report compared life cycle GHG emissions of exports of domestically produced LNG to Europe and Asia, compared with alternative fuel sources (such as regional coal and other imported natural gas) for electric power generation in the destination countries. The 2019 GHG Report Update demonstrated that the use of U.S. LNG exports for power production in European and Asian markets will not increase global GHG emissions from a life cycle perspective, when compared to regional coal extraction and consumption for power production, and in many scenarios, would decrease CO_2 emissions.[2]

"Rising emissions from China and India . . . could easily push warming past the 1.5° C goal, or even past the 2° goal." But "[a]ny reduction in emissions is beneficial," as federal regulators have recognized. "Does it matter how much the United States Reduces its Carbon Dioxide Emissions if China Doesn't Do the Same?" (http://www.climate.gov. (NOAA 8/20/23 attached hereto))

Accordingly, an increased supply of natural gas made possible through LNG exports can help countries move away from less environmentally friendly fuels by displacing the current consumption of coal in power generation and deterring the construction of additional coal-fired generation capacity. As noted in the Application, that prospect is now largely exhausted in the

1 Salina Roman-White, Srijama Rai, James Littlefield, George Cooney, Timothy Skone, P.E., DOE/FE NETL-2019/2041 (9/12/19).

2 *See id*. at 78, 85.

U.S.

Moreover, by using LNG produced in the U.S., stricter U.S. standards would apply to equipment used in wells, processing, gathering and transmission facilities, than would be the case of equipment located in other jurisdictions. For instance, in a document entitled "EPA Finalizes New Methane Rule That Will Cut Oil and Gas Pollution in Texas" (attached hereto), the Sierra Club on December 2, 2023 noted that the Environmental Protection Agency (EPA) had "finalized critical Clean Air Act protections against methane and other harmful pollution from the oil and gas industry, a major win for the climate and public health in Texas. These safeguards—which include first-ever standards for existing equipment while also strengthening standards for new equipment—are the culmination of years of advocacy by Sierra Club and its allies." The Sierra Club stated:

> According to EPA's analysis, the final standards are projected to avoid 58 million tons of methane emissions nationwide by 2038, as well as 16 million tons of volatile organic compounds and 590,000 tons of air toxins. These reductions will come from requirements for:
>
> Strengthened leak detection.
>
> Repair of all wells regardless of size or operation status . . . .
>
> Installation of non-polluting pneumatic equipment.
>
> A phased-in prohibition on routine flaring of gas at new wells.
>
> Program to leverage third-party monitoring data to identify and stop large emission events. [EPA Finalizes New Methane Rule That Will Cut Oil and Gas Pollution in Texas, 12/2/23]

> "Texas environment groups . . . praised the new regulation . . . Elizabeth Lieberknecht, a regulatory and legislative manager for the Environmental Defense Fund, called the regulation 'game changing in Texas'." [*Id.*]

The regulation requires companies to monitor their equipment for methane leaks.

> The "Administration has estimated that the regulation will cut 58 million tons of methane emissions between 2024 and 2038, which is nearly as much carbon dioxide emitted by the power sector in 2021."

Additionally, on April 10, 2024, new Bureau of Land Management rules were published that will reduce venting, flaring and leakage in the production and gathering of natural gas.[3] These regulations are not in effect in other natural gas-producing countries serving Asia, such as Russia and Indonesia. Additionally, if incremental facilities are constructed for LNG receipt, they will be modern and thus less susceptible to leaks.

[3] *See* "Waste Prevention, Production Subject to Royalties, and Resource Conservation", RIN 1004-AE79 Final Rule (89 Fed. Reg. 25378) 4/10/24, 43 C.F.R. §§ 3162.3-1, 3179.

Appendix H

Permitting Overview for Pipeline and Liquefaction Projects in Mexico

Appendix H
Pipeline Transportation

The natural gas that Applicant would supply would be transported over new pipelines such as the Roadrunner, Commanche Trail or Trans-Peco pipelines. The first phase of the Roadrunner pipeline was completed in 2016; additional stages were completed thereafter. The Comanche Trail Pipeline went into service on January 30, 2017. The Trans-Peco Pipeline began service in March 2017. In early 2024, the Saguaro project received approval to locate border-crossing facilities, at the Southern-most point in the U.S. of a 2.8 Bcf pipeline originating at Waha.[1] Thus there are several currently authorized means of transporting supplies from West Texas to the U.S.- Mexico border, which are not even nine years old.

The Trans-Pecos Pipeline is the northernmost segment of the Wahalajara pipeline network, which is designed to transport natural gas from Texas to Mexico. The Wahalajara system is named after the Waha oil field in Pecos County, Texas and the Mexican city of Guadalajara, which form the northern and southern extremities of the network. From north to south, the other pipelines included in the Wahalajara network are the Ojinaga-El Encino Gas Pipeline (completed in 2017), the El Encino-La Laguna Gas Pipeline (2018), the La Laguna-Aguascalientes Natural Gas Pipeline (2019), and the Villa de Reyes-Aguascalientes-Guadalajara Gas Pipeline (2020). Thus they are modern pipelines, built to the more rigorous standards currently in effect.

[1] *See Saguaro Connector Pipeline, LLC*, 186 FERC ¶ 61,114 (2024).

Appendix I

Additional Circumstances Associated With

Gato Negro Permitium Dos, S.A.P. 1 de C.V.

Appendix I
Additional Circumstances Associated With
Gato Negro Permitium Dos, S.A.P. 1 de C.V.

Midstream

- Pipeline age
  - o Pipeline system to Manzanillo relatively new and should have less methane slip
- Utilizing existing pipelines without any newbuilds

Downstream

- Power purchasing
  - o Purchasing power from the CFE -owned Manuel Alvarez Moreno natural gas plant.
  - o A combined cycle power plant that is relatively new and has an efficient heat rate for natural gas power plants.

- CryoSys (Technology Partner) is using best in class sealing technologies on compressor frames to minimize hydrocarbon leakages to negligible amounts.

- CryoSys are evaluating utilizing heat recovery coils to capture waste heat to pre-warm hot oil system for Acid Gas Removal, Heavy Hydro-Carbon recovery, and dehydration processes. This will reduce fuel gas usage and emissions.

- Going to Evaluate issues with boil off gas and flaring at existing KMS terminal and invest in minimizing these components. Options include:
  - o Proper utilization of Tank to minimize bog and flaring
  - o Reduction on N2 into the tank to minimize bog
  - o Capture system to re-liquefy boil off gas or send to fuel lines to offset fuel gas needs
  - o Investigate potential mechanical design issues with thermal insulation of existing tanks.

- High liquefaction efficiency
  - o CryoSys Process – Base high efficiency technology selection, with Technology upgrades weighed towards efficiency as opposed to capex concerns.
  - o Evaluation of Upgrades to overall system efficiency including Turbine Inlet Cooling and Secondary Mixed Refrigerant Cooling. Allocated design for future additions at a minimum.
- Evaluating carbon capture

Shipping

- Route to Asia
  - Closer to Asia markets
  - No need for traversing and waiting on Panama Canal delays
- LNG fuel vs. Petroleum fuel
  - Using LNG for ship fuel is lower intensity than petroleum marine fuels

Appendix J

E.I.A. U.S. Natural Gas Supply Disposition, and Prices Table 13

13. Natural Gas Supply, Disposition, and Prices

(trillion cubic feet, unless otherwise noted)

Supply, Disposition, and Prices	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	Average Annual Change 2022–2050
Production																														
Dry Gas Production 1/	36.47	36.49	35.57	35.73	36.18	36.14	36.44	36.68	37.04	37.47	37.97	38.55	39.05	39.50	39.86	40.22	40.49	40.73	40.87	40.99	41.16	41.28	41.35	41.51	41.34	41.54	41.61	41.69	42.07	0.5%
Supplemental Natural Gas 2/	0.07	0.07	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	-0.2%
Net Imports	**-4.18**	**-5.14**	**-5.47**	**-5.97**	**-6.57**	**-7.05**	**-7.56**	**-7.94**	**-8.55**	**-9.25**	**-9.90**	**-10.55**	**-11.12**	**-11.52**	**-11.82**	**-12.03**	**-12.09**	**-12.15**	**-12.06**	**-12.02**	**-12.02**	**-11.98**	**-11.94**	**-11.85**	**-11.80**	**-11.75**	**-11.71**	**-11.66**	**-11.61**	**3.7%**
Pipeline 3/	-0.25	-0.66	-0.93	-1.14	-1.30	-1.42	-1.62	-1.72	-1.73	-1.83	-1.85	-1.92	-1.99	-2.10	-2.18	-2.21	-2.16	-2.22	-2.11	-2.09	-2.09	-2.05	-2.00	-1.92	-1.87	-1.83	-1.77	-1.73	-1.69	7.0%
Liquefied Natural Gas	-3.93	-4.48	-4.54	-4.83	-5.27	-5.63	-5.94	-6.23	-6.83	-7.43	-8.04	-8.63	-9.13	-9.43	-9.64	-9.83	-9.93	-9.93	-9.94	-9.93	-9.93	-9.93	-9.94	-9.93	-9.93	-9.93	-9.94	-9.93	-9.93	3.4%
Total Supply	**32.35**	**31.42**	**30.16**	**29.82**	**29.68**	**29.15**	**28.95**	**28.80**	**28.55**	**28.28**	**28.14**	**28.07**	**27.99**	**28.04**	**28.10**	**28.25**	**28.46**	**28.65**	**28.88**	**29.03**	**29.21**	**29.36**	**29.48**	**29.72**	**29.60**	**29.85**	**29.97**	**30.10**	**30.51**	**-0.2%**
Consumption by Sector	**32.00**	**30.83**	**29.65**	**29.37**	**29.28**	**28.79**	**28.62**	**28.48**	**28.23**	**27.96**	**27.83**	**27.74**	**27.67**	**27.68**	**27.78**	**27.93**	**28.16**	**28.34**	**28.56**	**28.72**	**28.90**	**29.07**	**29.19**	**29.33**	**29.32**	**29.44**	**29.64**	**29.79**	**30.01**	**-0.2%**
Residential	4.96	4.99	4.76	4.79	4.81	4.83	4.84	4.83	4.82	4.81	4.79	4.78	4.77	4.76	4.75	4.75	4.74	4.73	4.73	4.72	4.72	4.72	4.72	4.72	4.71	4.71	4.71	4.71	4.71	-0.2%
Commercial	3.47	3.47	3.37	3.41	3.44	3.46	3.49	3.51	3.52	3.53	3.53	3.54	3.53	3.53	3.53	3.52	3.51	3.51	3.50	3.49	3.48	3.48	3.48	3.47	3.46	3.46	3.45	3.45	3.45	0.0%
Industrial 4/	10.48	10.23	10.13	10.28	10.52	10.65	10.79	10.85	10.90	10.92	10.98	11.02	11.09	11.15	11.24	11.31	11.37	11.47	11.52	11.60	11.68	11.76	11.85	11.91	11.92	12.00	12.12	12.21	12.33	0.6%
Other Industrial 4/	8.50	8.21	8.12	8.26	8.47	8.61	8.71	8.77	8.80	8.81	8.85	8.87	8.93	8.97	9.03	9.09	9.14	9.21	9.27	9.34	9.41	9.48	9.54	9.59	9.59	9.67	9.76	9.84	9.95	0.6%
Lease and Plant Fuel 5/	1.98	2.02	2.01	2.02	2.04	2.04	2.08	2.08	2.09	2.10	2.13	2.15	2.17	2.18	2.20	2.22	2.23	2.25	2.25	2.25	2.27	2.29	2.31	2.32	2.33	2.33	2.36	2.37	2.38	0.7%
Natural Gas-to-Liquids Heat and Power 6/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Natural Gas to Liquids Production 7/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	--
Transportation	1.30	1.27	1.23	1.21	1.23	1.22	1.21	1.24	1.29	1.34	1.39	1.45	1.50	1.53	1.55	1.57	1.59	1.60	1.61	1.63	1.64	1.65	1.67	1.68	1.70	1.72	1.74	1.76	1.78	1.1%
Motor Vehicles, Trains, and Ships	0.10	0.11	0.12	0.12	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.19	0.20	0.21	0.22	0.23	0.24	0.25	0.27	0.28	0.30	3.9%
Pipeline and Distribution Fuel	0.87	0.79	0.73	0.70	0.67	0.63	0.59	0.59	0.59	0.59	0.60	0.60	0.61	0.61	0.61	0.61	0.62	0.61	0.62	0.63	0.63	0.64	0.64	0.65	0.65	0.66	0.66	0.67	0.67	-0.9%
Fuel Used to Liquefy Gas for Export 8/	0.32	0.36	0.37	0.39	0.43	0.46	0.49	0.51	0.56	0.61	0.66	0.70	0.74	0.77	0.79	0.80	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	3.4%
Electric Power 9/	11.80	10.87	10.16	9.68	9.27	8.62	8.29	8.05	7.71	7.37	7.12	6.95	6.77	6.71	6.71	6.78	6.94	7.04	7.20	7.28	7.38	7.45	7.47	7.55	7.52	7.55	7.62	7.66	7.74	-1.5%
Discrepancy 10/	**0.35**	**0.58**	**0.52**	**0.46**	**0.41**	**0.36**	**0.32**	**0.32**	**0.31**	**0.32**	**0.31**	**0.32**	**0.32**	**0.36**	**0.32**	**0.32**	**0.31**	**0.31**	**0.31**	**0.32**	**0.31**	**0.30**	**0.29**	**0.39**	**0.29**	**0.42**	**0.32**	**0.31**	**0.50**	**--**
Natural Gas Prices																														
Natural Gas Spot Price at Henry Hub (2022 dollars per million Btu)	**6.52**	**5.27**	**4.07**	**3.49**	**3.07**	**2.85**	**2.80**	**2.83**	**2.91**	**3.04**	**3.21**	**3.42**	**3.57**	**3.68**	**3.69**	**3.74**	**3.87**	**3.79**	**3.94**	**4.02**	**4.01**	**3.95**	**3.91**	**3.91**	**3.91**	**3.87**	**3.85**	**3.78**	**3.77**	**-1.9%**
Delivered Prices (2022 dollars per thousand cubic feet)																														
Residential	14.85	14.61	13.32	12.57	11.94	11.52	11.24	11.30	11.34	11.45	11.54	11.70	11.82	11.93	11.99	12.07	12.22	12.22	12.32	12.42	12.45	12.43	12.39	12.45	12.77	12.76	12.72	12.73	12.76	-0.5%
Commercial	11.42	10.73	9.69	9.19	8.79	8.57	8.47	8.51	8.54	8.62	8.69	8.83	8.94	9.03	9.06	9.14	9.26	9.26	9.35	9.43	9.45	9.43	9.38	9.43	9.64	9.60	9.55	9.55	9.58	-0.6%
Industrial 11/	7.62	6.51	5.36	4.77	4.32	4.07	3.99	4.00	4.06	4.17	4.29	4.45	4.58	4.70	4.72	4.76	4.89	4.84	4.96	5.04	5.03	4.98	4.93	4.93	4.89	4.85	4.82	4.78	4.77	-1.7%
Transportation 12/	18.23	16.93	15.47	14.86	14.14	13.78	13.52	13.38	13.30	13.29	13.27	13.31	13.31	13.28	13.14	13.03	13.03	12.81	12.79	12.73	12.59	12.41	12.23	12.15	12.78	12.61	12.45	12.32	12.24	-1.4%
Electric Power 9/	7.26	5.81	4.63	4.00	3.50	3.19	3.07	3.06	3.10	3.18	3.26	3.39	3.51	3.63	3.67	3.72	3.86	3.83	3.97	4.05	4.03	3.98	3.91	3.90	3.87	3.84	3.82	3.77	3.76	-2.3%
Average 13/	**9.21**	**8.27**	**7.11**	**6.53**	**6.07**	**5.83**	**5.73**	**5.77**	**5.85**	**5.98**	**6.10**	**6.26**	**6.40**	**6.51**	**6.54**	**6.58**	**6.70**	**6.65**	**6.74**	**6.81**	**6.80**	**6.74**	**6.68**	**6.69**	**6.76**	**6.72**	**6.68**	**6.64**	**6.63**	**-1.2%**
Natural Gas Spot Price at Henry Hub (nominal dollars per million Btu)	**6.52**	**5.48**	**4.34**	**3.80**	**3.41**	**3.24**	**3.25**	**3.35**	**3.54**	**3.78**	**4.07**	**4.44**	**4.75**	**5.02**	**5.15**	**5.33**	**5.63**	**5.64**	**5.99**	**6.26**	**6.39**	**6.43**	**6.52**	**6.66**	**6.81**	**6.91**	**7.04**	**7.08**	**7.23**	**0.4%**
Delivered Prices (nominal dollars per thousand cubic feet)																														
Residential	14.85	15.22	14.21	13.70	13.29	13.10	13.06	13.41	13.77	14.21	14.66	15.21	15.74	16.26	16.71	17.20	17.79	18.20	18.75	19.32	19.80	20.23	20.63	21.21	22.28	22.78	23.26	23.83	24.47	1.8%

Appendix K
Excerpts from the latest Lazard Report

LAZARD

LCOE+

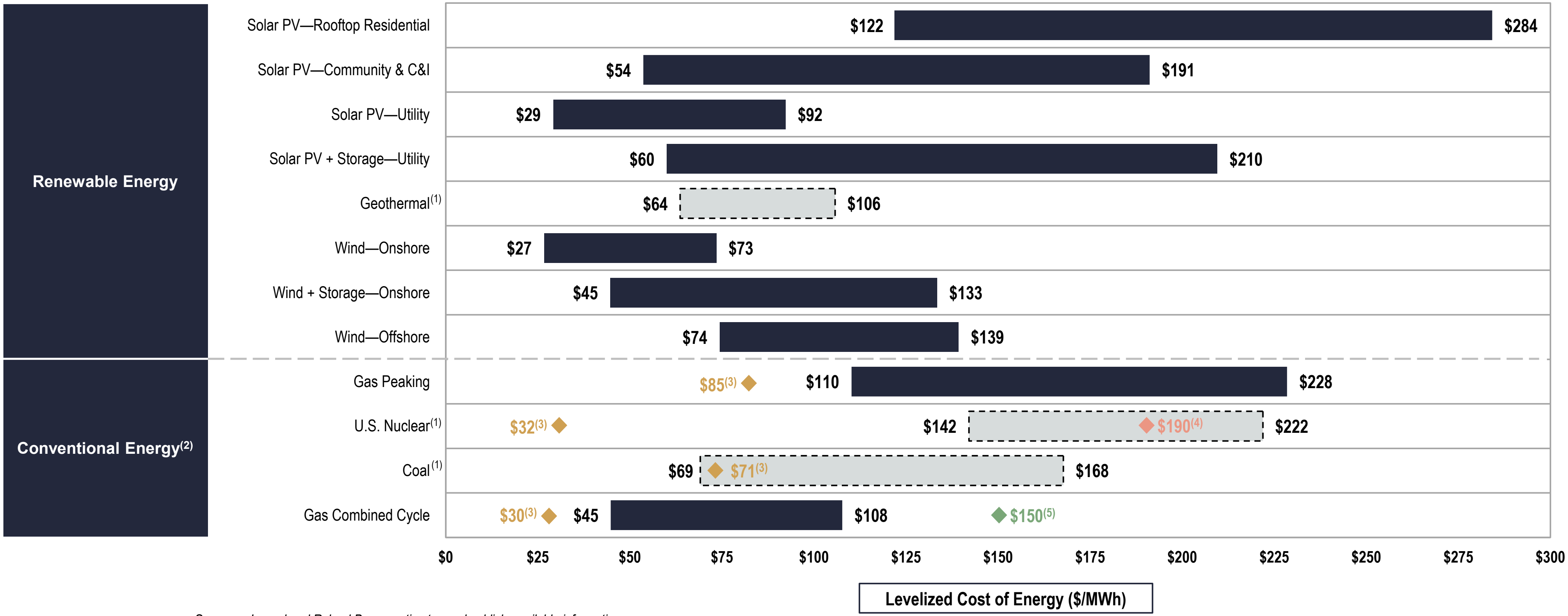
LEVELIZED COST OF ENERGY+

June 2024

WITH SUPPORT FROM Roland Berger

Levelized Cost of Energy Comparison—Version 17.0

Selected renewable energy generation technologies remain cost-competitive with conventional generation technologies under certain circumstances



Source: *Lazard and Roland Berger estimates and publicly available information.*

Note: Here and throughout this analysis, unless otherwise indicated, the analysis assumes 60% debt at an 8% interest rate and 40% equity at a 12% cost. See page titled "Levelized Cost of Energy Comparison—Sensitivity to Cost of Capital" for cost of capital sensitivities.

(1) Given the limited public and/or observable data available for new-build geothermal, coal and nuclear projects the LCOE presented herein reflects Lazard's LCOE v14.0 results adjusted for inflation and, for nuclear, are based on then-estimated costs of the Vogtle Plant. Coal LCOE does not include cost of transportation and storage.

(2) The fuel cost assumptions for Lazard's LCOE analysis of gas-fired generation, coal-fired generation and nuclear generation resources are $3.45/MMBTU, $1.47/MMBTU and $0.85/MMBTU respectively, for year-over-year comparison purposes. See page titled "Levelized Cost of Energy Comparison—Sensitivity to Fuel Prices" for fuel price sensitivities.

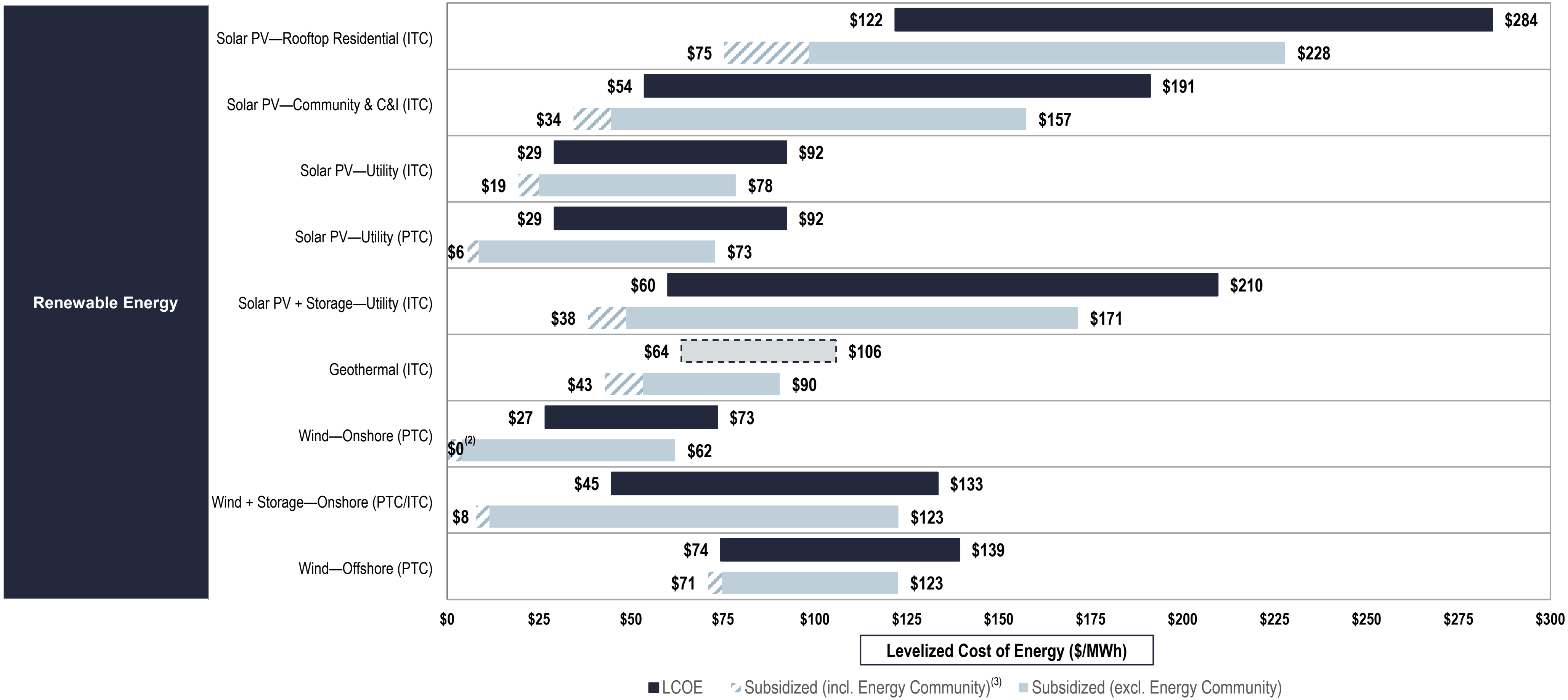
(3) Reflects the average of the high and low LCOE marginal cost of operating fully depreciated gas peaking, gas combined cycle, coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities. Analysis assumes that the salvage value for a decommissioned gas or coal asset is equivalent to its decommissioning and site restoration costs. Inputs are derived from a benchmark of operating gas, coal and nuclear assets across the U.S. Capacity factors, fuel, variable and fixed operating expenses are based on upper- and lower-quartile estimates derived from Lazard's research. See page titled "Levelized Cost of Energy Comparison—New Build Renewable Energy vs. Marginal Cost of Existing Conventional Generation" for additional details.

(4) Represents the illustrative midpoint LCOE for Vogtle nuclear plant units 3 and 4 based on publicly available estimates. Total operating capacity of ~2.2 GW, total capital cost of ~$31.5 billion, capacity factor of ~97%, operating life of 60 – 80 years and other operating parameters estimated by Lazard's LCOE v14.0 results adjusted for inflation. See Appendix for more details.

(5) Reflects the LCOE of the observed high case gas combined cycle inputs using a 20% blend of green hydrogen by volume (i.e., hydrogen produced from an electrolyzer powered by a mix of wind and solar generation and stored in a nearby salt cavern). No plant modifications are assumed beyond a 2% increase to the plant's heat rate. The corresponding fuel cost is $6.66/MMBTU, assuming ~$5.25/kg for green hydrogen (unsubsidized PEM). See LCOH—Version 4.0 for additional information.

Levelized Cost of Energy Comparison—Sensitivity to U.S. Federal Tax Subsidies(1)

The Investment Tax Credit ("ITC"), Production Tax Credit ("PTC") and Energy Community adder, among other provisions in the IRA, are important components of the LCOE for renewable energy technologies



Source: *Lazard and Roland Berger estimates and publicly available information.*

Note: Unless otherwise indicated, this analysis does not include other state or federal subsidies (e.g., domestic content adder, etc.). The IRA is comprehensive legislation that is still being implemented and remains subject to interpretation—important elements of the IRA are not included in our analysis and could impact outcomes.

(1) This sensitivity analysis assumes that projects qualify for the full ITC/PTC, have a capital structure that includes sponsor equity, debt and tax equity and assumes the equity owner has taxable income to monetize a portion of the tax credits.

(2) Results at this level are driven by Lazard's approach to calculating the LCOE and selected inputs (see Appendix A for further details). Lazard's LCOE analysis assumes, for year-over-year reference purposes, 60% debt at an 8% interest rate and 40% equity at a 12% cost (together implying an after-tax IRR/WACC of 7.7%). Implied IRRs at this level for Wind—Onshore (PTC) is 13% (i.e., the value of the PTC and Energy Community adder result in an implied IRR greater than the assumed 12%).

(3) This sensitivity analysis assumes that projects qualify for the full ITC/PTC and also includes an Energy Community adder of 10% for ITC projects and $3/MWh for PTC projects.

Appendix L
NREL 2023 Study, excerpt

Cost Projections for Utility-Scale Battery Storage: 2023 Update

Wesley Cole and Akash Karmakar

National Renewable Energy Laboratory

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

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Contract No. DE-AC36-08GO28308

Technical Report
NREL/TP-6A40-85332
June 2023

Executive Summary

In this work we describe the development of cost and performance projections for utility-scale lithium-ion battery systems, with a focus on 4-hour duration systems. The projections are developed from an analysis of recent publications that include utility-scale storage costs. The suite of publications demonstrates wide variation in projected cost reductions for battery storage over time. Figure ES-1 shows the suite of projected cost reductions (on a normalized basis) collected from the literature (shown in gray) as well as the low, mid, and high cost projections developed in this work (shown in black). Figure ES-2 shows the overall capital cost for a 4-hour battery system based on those projections, with storage costs of $245/kWh, $326/kWh, and $403/kWh in 2030 and $159/kWh, $226/kWh, and $348/kWh in 2050. Battery variable operations and maintenance costs, lifetimes, and efficiencies are also discussed, with recommended values selected based on the publications surveyed.

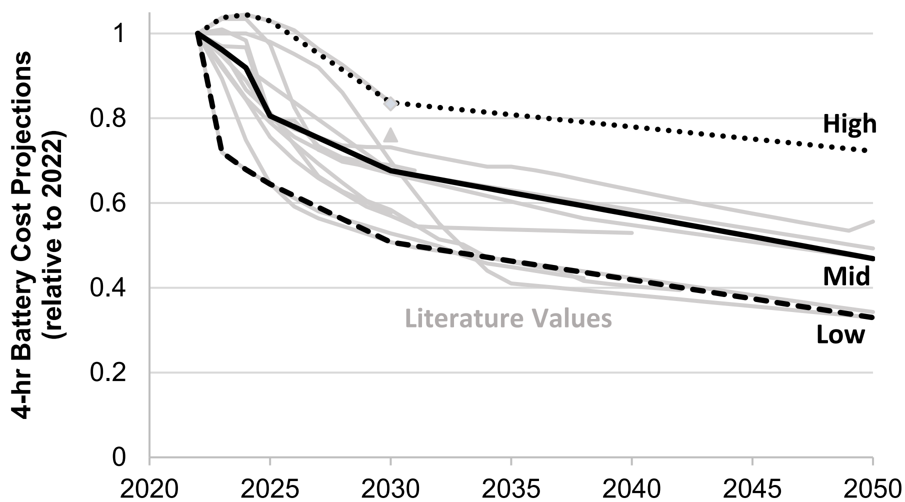

Figure ES-1. Battery cost projections for 4-hour lithium-ion systems, with values normalized relative to 2022. The high, mid, and low cost projections developed in this work are shown as bolded lines.

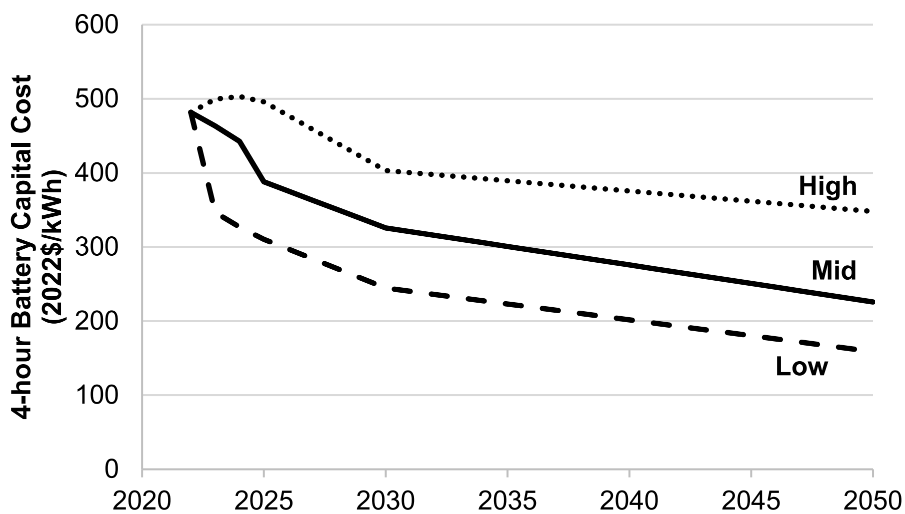

Figure ES-2. Battery cost projections for 4-hour lithium-ion systems.

Appendix M
Memorandum (LBNL-44698) memo to Skip Laiter,
EPA Office of Atmospheric Programs, from Jonathan Kooney, *et al)*

ERNEST ORLANDO LAWRENCE
BERKELEY NATIONAL LABORATORY

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MEMORANDUM (LBNL-44698)

December 9, 1999

To: Skip Laitner, EPA Office of Atmospheric Programs
From: Jonathan Koomey, Kaoru Kawamoto, Bruce Nordman, Mary Ann Piette, and Richard E. Brown
RE: Initial comments on "The Internet Begins with Coal"
cc: Mark P. Mills, Rob Bradley, Amory Lovins, Joe Romm, Alan Meier, Alan Sanstad, and Erik Brynjolfsson
Download this memo and related data at: http://enduse.lbl.gov/projects/infotech.html

SHORT SUMMARY

This memo explores the assumptions in Mark P. Mills' report titled *The Internet Begins with Coal* that relate to current electricity use "associated with the Internet". We find that Mills has significantly overestimated electricity use, in some cases by more than an order of magnitude. We adjust his estimates to reflect measured data and more accurate assumptions, which reduces Mills' overall estimate of total Internet-related electricity use by about a factor of eight.

INTRODUCTION

At your request, we have begun to explore some of the assumptions in Mark P. Mills' report titled *The Internet Begins with Coal* (Mills 1999). In this memo, we restrict our comments to a few key assumptions in Part 7 of Mills' report, where he estimated total current electricity demand associated with the Internet. We do not address in this memo any of Mills' assertions about future growth of Internet electricity use, nor do we address any comments he made about the types of electricity supply technologies that would support any such increases in electricity demand. As more data become available, we expect refine the estimates in this memo, which must at this time be treated as preliminary.

The existence of the Mills report highlights the critical need for comprehensive data on electricity used by office equipment and associated network related-hardware. The last time such a comprehensive report was done (Koomey et al. 1995) was prior to the Internet becoming such an important force in the U.S. economy. That report did not address energy used by network hardware, but it did deal explicitly with stocks, energy use per unit, and operating hours to estimate total electricity used by commercial sector office equipment in the U.S. It compiled measured data on many of these parameters, which guided the creation of the scenarios generated in that report. This kind of comprehensive analysis, updated to reflect recent market developments and encompassing a broader scope, would resolve many lingering questions on this issue.

From a methodological perspective, it is problematic to assess only one portion (e.g., the Internet portion) of electricity used by office equipment in the U.S. In the absence of a complete accounting for all office equipment (as found in the Koomey et al. report), the accuracy of the calculations cannot rely on the checks and balances that such a complete accounting would enforce. For example, the total number of personal computers (PCs) is known with much more precision than the number of PCs associated with the Internet, so trying to estimate the latter without first estimating the former will yield a much less certain result.

There are difficult boundary issues in this assessment as well.[1] Mills chose to estimate the electricity used by the Internet and associated equipment, but he did not attempt to assess the effects of *structural changes* in the economy that are enabled by the existence of the Internet. These structural changes will almost certainly affect electricity and energy use. Without assessing the effect of these changes, the *net* effect of the Internet cannot be calculated, yet that is really what we care about. Given the large productivity benefits induced by computer hardware when properly used, it is plausible to speculate that these changes will be large enough to matter.

Mills also makes the assumption that all usage associated with the Internet is incremental. Instead it is actually more likely that at least some of this usage is *substituting* for other energy consuming functions that preceded the Internet (the Internet is expanding uses for the PC at the expense of other energy-using devices). Private computer networks and fax machines, for example, are increasingly being displaced by the Internet. Computer use is substituting for other forms of entertainment, like TV. Even voice communications (formerly the province of the telephone network) are being carried over the net. Such displacement effects represent another difficult boundary issue not treated in Mills' analysis.

In addition, the definition of which hardware is "associated with the Internet" is at best an imprecise one. Is a home computer "associated with the Internet"? People might use it for writing, for doing calculations, for analyzing personal finances, for creating party invitations, or for accessing the net. Does that mean that ALL of its energy use can be attributed to the Internet, or just a part? If just a portion, how much should be allocated to Internet use? Many of the reasons for owning a computer are independent of the Internet, and taken together justify the purchase of a computer. The same conclusion holds even more strongly for PCs in offices, since there are many reasons beyond Internet access for companies to invest in PCs. This kind of arbitrary allocation makes for calculations that are at best limited in usefulness.

In some sense, Mills is asking the wrong question by focusing on the Internet-related portion of electricity use by office equipment. Future studies should analyze total electricity used by this equipment, and not focus on what is Internet related, because these boundary issues are so difficult to resolve.

We turn now to specific assumptions that Mills made in his analysis. There are only a small number of assumptions that drive his results. Table 1 shows that of the 295 TWh that Mills calculates for Internet-related electricity use, more than half is in just three categories: Mainframe computers that serve "Major dot com company" web sites, Web sites using

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[1] The ISO 14000 standards documents (particularly ISO 14040 and 14041) deal with the methodological issues surrounding such boundary issues. See http://www.iso.ch.

smaller servers, and telephone central offices. An additional 25% of Mills' total energy use is associated with use of PCs in offices and homes, and another 8% of Mills' total energy use is associated with routers. The rest (10%) is associated with the embodied energy to manufacture the equipment. We treat each of these categories in turn.

Table 1: Summary of Mills' estimates of current electricity use associated with the Internet circa 1998

	# of units Millions	*Elect. Used TWh/year*	*% of total*	*Cumulative %*
1) Major dot-com companies	0.033	72	24%	24%
2) Web sites	4	52	18%	42%
3) Telephone central offices	0.01	43	15%	57%
4) PCs in offices for all purposes	40	44	15%	71%
5) PCs at home for all purposes	41	31	10%	82%
6) Routers on Internet	2	16	5%	87%
7) Routers in LANS and WANs	1	8	3%	90%
8) Energy to manufacture equipment	19.5	29	10%	100%
Total		295	100%	

1) MAINFRAME COMPUTERS FOR 'MAJOR DOT COM COMPANIES'

Mills takes the number of mainframe computers in the U.S. from the ITI data book, which is the industry source for such numbers. He assumes that 10% of all mainframe computers in companies other than the major Internet companies are devoted solely to serving web sites. We have no way to judge the plausibility of this assumption, but we note that many such computers serve multiple functions (it is their multitasking abilities that make them so useful). Mills' choice to add the 10% of total mainframe installations to the number of mainframes/web farms in "Major dot-com" companies is an arbitrary one, but one with which we do not have the data to quibble.

Definitions of mainframe computers are not well established, and it appears that Mills did not use the same definitions for his stock and power estimates. The stock estimates rely on the ITI data book numbers, which count any computer costing more than $350,000 as a mainframe. The power estimates he used appear to be inconsistent with this definition.

Mills assumes that each mainframe uses 250 kW, 8760 hours per year. Half of this is assumed to be direct electricity used by the computer, and half for cooling. If the computer's direct consumption is 125 kW, this would place it in the ballpark of LBNL's Phase I supercomputer, installed in July 1999, which draws 150 kW (actual, not rated). It has about 600 processors, and is one of the most powerful in the world. The LBNL supercomputer cost tens of millions of dollars, but such supercomputers number only in the hundreds in the U.S. The bulk of mainframe installations are nowhere near the computing power of a supercomputer, yet that is the power use Mills chose for the typical mainframe.

For LBNL's Phase I supercomputer, the actual power use is about 0.25 kW per CPU.[2] If we use this consumption per CPU, the 125 kW Mills assumes is equivalent to a supercomputer

[2] Note that the LBNL Phase II Supercomputer, now under construction, will use about 0.1 kW per CPU. Source: Howard Walter at LBNL, who is designing the power systems for the new LBNL NERSC building. He generously provided numbers on the power requirements of supercomputers and their associated cooling loads.

with 520 processors. This represents far more processing power than a typical mainframe computer.

The IBM S/390 Enterprise server, which Mills' report cites as an example of the latest mainframe technology, has a rated (maximum) power of up to 6.4 kVA (roughly equivalent to 6.4 kW), depending on the number of processors. For the reasons described in Nordman (1999), the *actual* power use of almost all types of electronic equipment is typically one-half to one-third of the rated power (the rated power is the maximum power that the power supply will consume under fully loaded, worst case conditions). If the actual power is half of the rated power, this machine would use 3.2 kW for typical installations. Of course, IBM's server is relatively new and it relies on CMOS technology to reduce power use, so it probably uses less power than an older mainframe. The rated power may also not include peripheral equipment that would be included in a typical mainframe installation.

It is clear that 125 kW is a much larger power number than has been used in such analyses in the past. The Koomey et al. (1995) report estimates power used by older (1985-1990) mainframes at 25 kW, declining to 10 kW by 1999 (an estimate for 1999 which is validated by the S/390 data described in the previous paragraph). The recent Swiss study by Meyer and Schaltegger (1999) used 30 kW for the average power of each of the roughly 1000 mainframes in Switzerland.

We checked the price of the S/390 on the IBM web site and found that its cost is well above ITI's $350k cutoff for mainframes (S/390s cost millions of dollars). We believe, as Mills also does, that this machine is representative of mainframe computers now being installed. If we accept the 3.2 kW direct power use of the S/390 and quadruple it to account for peripheral equipment, that still leaves our estimate of power used per mainframe (12.8 kW) at about one tenth of what Mills assumes.

Cooling is at most 50% of direct power consumption, not 100% as Mills assumes. This result follows from the compressor-based cooling technologies commonly used in commercial buildings and computer rooms, which have Coefficients Of Performance (COPs) of 2.0 or better. A COP of 2.0 implies that 1 unit of electricity is consumed to move 2 units of heat out of the conditioned space. We consulted with the supercomputer team at LBNL, who use 50% additional power for cooling as their best guess for maximum cooling loads when designing a new supercomputer (although in actual practice, 30% is more typical in the Bay Area).

Using our 12.8 kW direct power use estimate, combined with a 50% multiplier for cooling energy, leaves us at 19.2 kW per mainframe. If we replace Mills' assumption of 250 kW with this new estimate, total electricity used by the Major dot-com companies becomes 5.5 TWh, a reduction of 66.5 TWh or about a factor of thirteen. By itself, this correction reduces Mills' estimate of electricity used by the Internet by 22%.

2) WEB SERVERS

Mills refers to an article titled "WWW Hosts 5 Million Web Sites" (http://www.nua.ie/surveys) to justify his assumption of the number of web servers. He takes 70% of 5 million, which rounds to 4 million servers. The problem is that the article to which Mills refers talks about web sites NOT servers. One server can host dozens of web sites (a fact that Mills acknowledges in his report), so the number of servers is much lower than the number of sites. We assume, for purposes of these calculations, that each server hosts 5 sites (although that is likely to be an underestimate). In practice, some servers will have just one site, and others will have many. This correction factor alone reduces Mills' estimate of electricity use for this component by 80%.

The power used by mini-computers and workstations is assumed by Mills to equal 1.5 kW, 1 kW of which is direct power used by the computer, and 0.5 kW is from peripherals, "especially data backup". Data backup only runs once a day, and services many CPUs. It is unlikely that 0.5 kW per CPU is a reasonable estimate for this service.

Based on the discussion of PC power use below, we reduce Mills’ 1.5 kW estimate by a factor of 5, to 0.3 kW. With both corrections (for number of units and power per unit), total power used by U.S. web servers is reduced by a factor of 25, to 2.1 TWh.

3) TELEPHONE CENTRAL OFFICES

Telephone central offices are the next most important item in Mills' list, but much more information and documentation is needed to justify the calculations, particularly the number of such offices and the power use per office.

Mills' estimates that central offices each use 500 kW. His table indicates that there are 25,000 such central offices in the U.S. In fact, most of these central offices are significantly smaller than Mills' assumes (between 30 and 50 kW). We are working on getting an accurate distribution of such central offices by power level, but in the absence of those data, we took another tack.

Our contact at a major phone company reports that a central office uses about 3.3 kWh per thousand minutes of so called "dial equipment minutes" or DEQ (a standard measure of phone connect time). FCC (1999) reports total DEQ for the U.S. of 3,612 billion minutes in 1997. These two numbers together imply electricity used by all central offices of 12 TWh/year. To make this number comparable to Mills' estimate, we multiply this figure by 40%, to get 4.8 TWh/year.

With this revised estimate, power used by central offices is reduced by 37 TWh, or about a factor of nine.

4) OFFICE PCs

The power used by most personal computers is assumed by Mills to equal 1 kW. This estimate is assumed to include all peripheral equipment associated with PCs, as well as some unspecified other equipment. Without a detailed accounting of his assumptions about this equipment, it is difficult to determine what he assumed. However, there is a large body of literature on actual power used by such equipment. A recent power measurement of a 500 MHz Pentium III PC that had no power management showed average power over the course of a day of about 40 W for the CPU.[3] A typical 17" monitor uses about 90 W in active mode.

Of course, most PCs and monitors now are capable of power management (which neither of the above measurements include), so that over the course of a day, these power numbers would be reduced. ENERGY STAR PCs power down to less than 30 W, and typical ENERGY STAR monitors power down to less than 10 W. Whether power management is enabled in many cases is an open question (recent surveys found roughly a third of PCs and monitors had power management correctly enabled in offices), but for the sake of argument, we ignore it.

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[3] Personal communication with Bruce Nordman, LBNL, November 1999.

Peripheral equipment is often shared. In our office, 20 people share a workgroup printer (HP 8000 DN). We metered this printer, and it draws about 163 W in active mode (when printing), and about 120 W in standby mode. In sleep mode it draws about 30 W, and on average, including sleep modes and printing, it uses about 50 W. Even ignoring the power management of the printer, and assuming it is constantly printing, it would add only 8 W per CPU to our estimate of average PC power. For home PCs, most printers will be inkjets, which typically draw less than 30W even in active mode.

It is not clear what other equipment Mills is referring to in his 1 kW estimate, but we feel it is unlikely to push the average power used by PCs and peripherals to greater than 200 W (and with power management, we feel strongly that 200 W average power is an overestimate). For purposes of these calculations, we use 200 W instead of Mills' 1 kW estimate, and recalculate electricity used by PCs to reflect this revised estimate. If he believes that other "behind-the-wall" components account for a significant amount of power use (800 W/CPU in this case), he needs to specify, item by item, the number and power use of all these components. We examined the "behind the wall" components of the LBNL computer network, but we were unable to figure out how these components, most of which serve multiple CPUs, could possibly add up to 800 W per CPU (tens of watts per CPU over and above router power use is more like it. See Nordman 1999 for details).

The power used by high end personal computers is assumed by Mills to equal 2 kW. We reduce this estimate also by a factor of five, to 400 W, even though this is almost certainly an overestimate (doubling the CPU power for the 500 MHz Pentium III above and assuming a 21 inch monitor at about 120 Watts only leads to actual power use of 200 Watts, without considering power management).

For usage of PCs at the office, Mills assumes twelve hours per week, which is the same as that assumed for home PCs (see point 5, below). It is important to note the inherent arbitrariness of attempting to calculate what part of office PC use is "associated with the Internet". We have no data for what portion of office computer use is "associated with the Internet". The only adjustment we make to Mills' usage numbers in this category is to reduce usage for typical office PCs to seven hours per week from 12 hours per week, to reflect our revision in the home PC usage number below (this adjustment preserves consistency between our methodology and that of Mills). We do not change usage assumptions for PCs at offices behind a firewall or PCs used in commercial Internet services.

With these corrections, PCs in offices use about 7.2 TWh, a reduction of 84% from Mills' estimate.

5) PCS AT HOME

Mills' assumption of 1 kW power draw for home PCs is subject to the same issues examined under point 4, and hence we reduce his 1 kW by a factor of 5, to 0.2 kW. Even though peripheral equipment in a home is associated typically with one PC instead of many in a work environment, that equipment is not always on when the computer is on, and it is likely to be lower power versions of that equipment (e.g. ink jets instead of laser printers, low end scanners, etc.).

We now turn to usage of home PCs. Mills assumes twelve hours per week of usage for these computers, based on an Intelliquest study of home users, but he acknowledges that "other surveys show lower averages". He cites the Neilson/NetRatings March 1999 survey at seven hours per month (less than two hours per week). Another quite recent study (7 December 1999) shows usage of five to eight hours per month, which is also about two hours per week (http://www.nua.ie/surveys/?f=VS&art_id=905355453&rel=true). With this great a range in estimates of usage, it is important to be cautious in drawing conclusions. We were unable to locate any studies that indicated that average U.S. Internet users were logged on more than 12 hours per week, so we feel justified in treating this as an upper bound, with the likely average possibly as low as two hours per week. Even choosing seven hours per week (the midrange between those two estimates) would reduce Mills' estimates for electricity associated with home Internet use substantially.

Mills claims he is being conservative by assuming that

> every single PC and all its relevant peripherals accessing the Net is physically turned on and operating only the 12 hours per week from the Forrester Research (IntelliQuest) survey, and otherwise completely off. As a practical matter many (possibly most) are on at least 50 hours per week, many 24 by 7. A 'realistic' weekly 'on' time of 50 hours yields about the same rough kWh for a 200-300 W duty-cycle compensated PC as the conservative 12 hour/wk duty cycle does for a 1,000 peak W device (footnote 53, in Mills 1999).

The claim of conservatism is spurious. People use their computers for many other things besides Internet access, which is why at least some people have their computers on for 50 hours per week or more (though we doubt many home users do). According to the surveys cited below, the Internet-related component of home PC use is between two and 12 hours per week. That some people keep their home PCs on for more hours than that is irrelevant to Mills stated purpose, that of calculating electricity use "associated with the Internet".

Based on the surveys cited above, we choose usage of seven hours per week for typical home PC users, instead of 12 hours per week. We do not change hours of usage for PC power users or PCs in home offices.

With these corrections for power and usage, PCs in homes use about 5 TWh, a reduction of 84% from Mills’ estimate.

6) ROUTERS ON THE INTERNET

Mills' assessment of the number of routers seems inconsistent with our review of the market for these products. It is not clear why there would be twice as many high end routers as low end ones, when in fact the low end ones must be more numerous in any network with central nodes feeding dispersed nodes. We did not correct for this observation, but simply note it for future research. It is also not clear if Mills' stock estimates include switches and routers together, or just routers alone. This issue also must await further research.

Cisco’s very highest-end router, which is used in the highest throughput applications, has a rated power of 1.5 to 2 kW. The actual power used for this device will then be 0.75 to 1 kW, because rated power is typically two times the actual power (see text under item 1 above). Unfortunately for Mills’ argument, there are very few of these large routers sold every year. Based on a review of the high-end routers sold by Cisco systems, we find that more typical high end routers have rated power of 0.3 to 0.8 kW in typical use (actual power of 0.15 to 0.4 kW). We therefore reduce power use to 0.3 kW, from 1 kW.

Once we correct the power use, routers on the Internet show total consumption of 4.8 TWh, a reduction of 70% from Mills’ estimate.

7) ROUTERS ON LANS AND WANS

Routers on Local Area Networks and Wide Area networks (LANs and WANs) use much less power than Mills assumes. In the text of his report, he states that he uses 0.5 kW for the smaller routers, and 1 kW for the larger (Internet) routers. The total TWh calculations do not support this assertion--they imply that the 1 kW assumption was also used for the LAN and WAN routers (divide 8 TWh by 1 million routers, and then by 8760 hours, and you get just under 1 kW).

Mills therefore assumes 1 kW average power draw for all routers. Cisco's typical lower end routers (which account for the majority of all routers) range in rated power from 0.04 to 0.2 kW. We therefore reduce Mills' estimate by a factor of twenty, to reflect a rated power of 0.1 kW and an actual average low-end router power of 0.05 kW (this last factor of two correction from rated power to actual is the same as that used under points 1 and 6 above).

Once we correct the power use, routers on LANs and WANs show total consumption of 0.4 TWh, a reduction of 95% from Mills' estimate.

8) MANUFACTURING ENERGY

Manufacturing energy for computers on the Internet is the most difficult of these categories to analyze, because of the lack of data. The life-cycle assessment needed to calculate embodied electricity use of electronic equipment is a complicated exercise, and one that has only rarely been carried out. The most recent data we examined come from NEC, the largest computer manufacturer in Japan (Tekawa 1997).

NEC estimates total greenhouse gas emissions from manufacturing a desktop PC to be 128 kg/CO_2 equivalent (unfortunately, we don't at this time have much detail on the components of this calculation). Some of these emissions are non-CO_2 greenhouse gases, and some are from non-electricity related fuel use. Nevertheless, we can get an estimate for the upper bound to electricity used for manufacturing all parts of the PC by assuming all of these emissions come from electricity (electricity is more carbon intensive per unit of energy consumed than direct use of fuels). The average emissions factor for Japanese electricity production is about 0.42 kg CO_2 per kWh (115 g C per kWh). This factor implies total electricity use of about 300 kWh per desktop PC, which is an upper bound, as described above. NEC states that the electricity used to assemble their PCs is about 120 kWh per unit,[4] so total electricity use is between 120 kWh and 300 kWh per PC. We chose 300 kWh per PC, which is one fifth of Mills' estimate. This is an absolute upper bound. The true number is almost certainly lower than this.

With this factor of five correction, Mills estimate of 29 TWh for manufacturing energy is reduced to 6 TWh.

CONCLUSIONS

Table 2 shows Mills' estimates corrected as described above. In every category, his estimates must be reduced substantially (by factors of 3 to 25) to reflect more accurate assumptions. For all categories taken as a whole, Mills' estimates are reduced by 88%.

Mills' report does not contain enough detailed documentation to assess the reasonableness of many assumptions, but it is clear from the review of assumptions conducted above that he has vastly overestimated electricity use associated with the Internet. In addition, the value of such estimates is questionable, given the difficult boundary and allocation issues described above. It would be more useful to estimate total electricity used for all office equipment and

[4] Both Compaq and Dell appear to use significantly less electricity than NEC to assemble their PCs, and we are investigating this difference.

associated network equipment, because that number is inherently more reliable than deriving what fraction of such devices are "associated with the Internet".

Finally, the structural and substitution effects alluded to above are almost certainly large enough to matter. Future estimates of the impacts of the information technology revolution (which are larger in scope than those of just the Internet) should explicitly account for these effects.

Table 2: Corrected estimates of current electricity use associated with the Internet

	# of units Millions	*Elect. Used TWh/year*	*% of total*	*Cumulative %*
1) Major dot-com companies	0.033	5.5	15%	15%
2) Web sites	0.8	2.1	6%	21%
3) Telephone central offices	0.01	4.8	13%	35%
4) PCs in offices for all purposes	40	7.2	20%	55%
5) PCs at home for all purposes	41	5.0	14%	69%
6) Routers on Internet	2	4.8	13%	82%
7) Routers in LANS and WANs	1	0.4	1%	83%
8) Energy to manufacture equipment	19.5	6.0	17%	100%
Total		36	100%	

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Appendix N
Solar Learning Center document

Solar Learning Center > Solar Rebates & Incentives > Solar Incentives by State > The California Solar Mandate: Everything You Need to Know

The California Solar Mandate: Everything You Need to Know

By Shawn Showkati | Dec 28, 2023

Many states are paving the way towards a cleaner, emissions-free, and sustainable future. They are actively addressing climate change and innovating new solutions to fit their circumstances. This widespread support for climate action proves the dire need to protect and preserve our land for future generations to come. Many states have adopted different policies to reduce greenhouse gas emissions such as developing clean energy resources, promoting electric vehicles and other alternative fuel vehicles, and the like.

California, among many other states, has introduced specific goal-oriented targets, such as the 100% Renewable Portfolio Standard (RPS), 100% renewable power by 2045. One of the state's policies includes the California Solar Mandate that begins on January 1, 2020. This initiative by the California Energy Commission requires California to produce 50% of its energy through clean energy sources by 2030.

Whether you're a developer or a homebuyer, here's everything you need to know about the California Solar Mandate.

What is the California Solar Mandate?

The California Energy Commission introduced the California solar mandate which requires rooftop solar photovoltaic systems to be equipped on all new homes built on January 1, 2020 and beyond. This progressive ruling is the first of its kind in the US and is leading the nation to a cleaner energy future. This initiative by the CEC aims to spearhead California's milestone goal of producing 50% of the state's energy through clean energy sources by 2030.

Commissioner Andrew McAllister of California Energy Commission (CEC):

"The buildings that Californians buy and live in will operate very efficiently while generating their own clean energy. They will cost less to operate, have healthy indoor air and provide a platform for 'smart' technologies that will propel the state even further down the road to a low emissions future."

The 2019 Building Energy Efficiency Standards

The 2019 Building Energy Efficiency Standards requires that all new single-family homes and multi-family buildings that are under three stories must conform to the new solar code standards and is climate zone-specific depending on the sizing of a home's floor area. This applies to all houses, condos, and apartments that obtain building permits on or after January 1, 2020.

The amendment would also require an additional $9,500 in upfront costs to equip the new homes with the systems. However, due to the significantly reduced electric bills, it is assumed that the lifetime energy savings will offset these upfront costs.

The Building Energy Efficient Standards also encourages home batteries and heat-pump water heaters installed to the home's electrical system to improve the comfort of homes while also reducing energy costs.

The size of the equipped system will be determined by the ability to offset 100% of the home's electricity usage. Homes do not need to offset 100% of their home's energy with solar. In fact, homes can still rely on other energy sources that do not need to be offset by solar such as: gas stoves and central heating.

Related reading: What is SCE's New Home Energy Storage Pilot Incentive?

Who is exempt from the mandate?

Homes that are located in areas where the sun is often shaded are exempt from this mandate. This list also includes residents of high rise apartment buildings in larger new developments.

Who does it affect?

This mandate primarily affects the following: solar companies, housing developers, and potential homebuyers. As this mandate aims to increase the use of clean energy, the costs of solar is expected to continue to decrease decade after decade, as it already has.

As potential homebuyers make new home purchases with equipped solar, solar companies no longer have a need to acquire this category of customers and can concentrate on penetrating the market of homeowners with homes built before 2020. The costs of solar is expected to be reduced because housing developers can utilize their own workforce to complete the labor of the installation process. According to the CEC, potential homebuyers can expect new homes with PV systems to cost an additional $9,500. However, they can also expect to save an average of $19,500 over the life of the system.

In fact, a new study from a market research firm, CITE Research, shows that 70% of Americans would support a similar nationwide mandate.

As the fifth largest economy in the world, California has a lot of influence over other states and countries and as it continues to be the market leader for residential photovoltaic solar, it makes sense that the state is the first of its kind to implement this mandate. Limited research suggests that 70% of Americans would support a similar nationwide mandate. The cost of solar continues to decrease significantly, as a result, many states may take notice and adopt similar policies to reach their carbon-neutral goals. With the mandate in place, non-solar customers may be influenced by their solar neighbors as they notice more and more new housing developments include the technology. There's hope that this mandate will help promote climate action and normalize the use of clean energy such as solar, wind, and electric vehicles to reduce the consumption of fossil fuels and greenhouse emissions.

The Best Time to Go Solar is Now

If you're a homeowner looking to go solar in the near future, now is the best time. 2022 is the last year to claim your 26% solar tax credit. 2024 onwards, it'll be eliminated entirely. Solar.com's online solar marketplace helps homeowners easily gather free solar designs and multiple quotes from different companies so you don't have to. Use our solar calculator to assess your home's solar viability 100% online. If you have questions, our team of dedicated, unbiased, expert Energy Advisors will remotely guide you through the process to ensure you make the best choice.

Appendix O
NYSERDA web page

From Natural Gas to a Low-Carbon Future: Leading a Phased and Just Transition Off Fossil Fuels

> *New York is working to achieve a carbon-neutral economy by 2050 as envisioned by the Climate Act.*

To achieve New York's climate goals, we're working to move away from our reliance on natural gas – a fossil fuel that contributes to climate change – to heat homes and businesses, generate electricity, and power industrial processes. Methane – a greenhouse gas with significant global warming potential – is emitted during the production, processing, storage, transmission, and distribution of natural gas.

The transition from natural gas to energy sources that produce low levels of greenhouse gas emissions, such as wind and solar, may be one of the most challenging pieces of New York's efforts to decarbonize. As we increase our renewable energy resources, New York must also reduce energy demand by scaling up energy efficiency and electrification for heating. In certain hard-to-electrify sectors, we're pursuing research and development to prove and deploy deep decarbonization innovations to replace natural gas with alternatives with lower climate impact, such as green hydrogen and renewable natural gas.

This shift to a greener power grid and economy will bring new economic opportunities, and it's essential that displaced fossil fuel workers receive training and support to participate in the clean energy transition.

How We're Advancing Decarbonization for a Sustainable Future

Implementing a phased and just transition from natural gas requires creating inclusive opportunities to participate in and benefit from New York's climate mitigation efforts and clean energy future. It also means ensuring a good quality of life for all New Yorkers by prioritizing safety, equity, reliability, and affordability as we move towards a decarbonized economy.

NYSERDA is building market and workforce capacity, expanding product availability, and driving cost reduction for electrification and clean energy alternatives to replace natural gas.

NYSERDA's key strategies include:

- **Developing and publishing long-term plans** and roadmaps for advancing all-electric clean homes and buildings and green hydrogen as alternatives to fossil natural gas.
- **Phasing out support for natural gas and other fossil fuels** in all programs within two years and reorient investments around building shell improvements, electrification, and development of deep decarbonization alternatives.
- **Providing thought leadership** for gas system transition and engage in transition-related proceedings.
- **Proving-out solutions for low-to-moderate income electrification** – tailored to building stock and housing energy affordability needs.
- **Finalizing and implementing the 2 Million Climate-Friendly Homes Action Plan** to accelerate the transition of homes, including at least 40% LMI households, off inefficient and fossil-based heating systems.
- **Maintaining energy affordability for all New Yorkers**, prioritizing low- to moderate-income (LMI) households and strategies that can limit energy cost burden to below 6% of income.
- **Focusing on reducing the cost of clean heating and cooling through innovation** – demonstrate heat pump technologies and other low-carbon solutions in large commercial and multifamily buildings by working with property owners and manufacturers to deliver tailored solutions.
- **Supporting cutting-edge innovations** to reduce dependence on natural gas for heating, process loads, and peak demand needs, including long-duration storage.
- **Building understanding of and momentum for deep decarbonization technologies**, including clean hydrogen, carbon capture, and other forms of carbon-neutral tech, leveraging federal funding opportunities, such as the proposed Northeast Regional Clean Hydrogen Hub.

- **Evaluating holistic impacts from deep carbonization technologies**, including ongoing work to assess air pollution, land use and affordability impacts, and advancing opportunities with the greatest decarbonization potential.
- **Through the Hydrogen Roadmap, studying the decarbonization potential of clean hydrogen** across the key areas of energy efficiency, industrial electrification, low-carbon fuels, and carbon capture and storage and pursue federal funding to accelerate the deployment of innovative technologies within New York.
- **Supporting the development of thermal energy districts** that can deliver affordable, resilient heating and cooling to buildings while providing employment opportunities to support the transition of the gas workforce and establishing a regulatory framework for these systems.

Achieving a Just Transition Off Natural Gas

A carbon-neutral economy will create healthier communities and economic opportunities across the state. New York's electric grid will be zero-emission by 2040, improving local air quality and delivering reliable clean energy through an extensive network of wind, solar, hydro power, and energy storage. Residents and businesses will continue receiving support to adopt clean energy technologies, such as heat pumps, to promote affordable electrification while phasing out the use of natural gas.

Many New York buildings will electrify their heating and cooling through community heat pump systems and thermal energy networks. These scalable systems connect multiple buildings into a shared thermal network, which can leverage multiple sources of heat, such as geothermal energy and waste heat from industrial processes or electricity generation. The development of thermal networks will create quality jobs in New York's growing decarbonization sector, especially for those workers displaced in the transition to clean energy.

Appendix P

October 27, 2021 letter from D. Whitehead, Director of Environmental Permits, NY State Dept. of Environmental Conservation to Ms Brenda Collela.

NEW YORK STATE DEPARTMENT OF ENVIRONMENTAL CONSERVATION

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October 27, 2021

VIA EMAIL AND CERTIFIED MAIL

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Re: Notice of Denial of Title V Air Permit
DEC ID: 3-3346-00011/00017
Danskammer Energy Center – Town of Newburgh, Orange County
Title V Air Permit Application

Dear Ms. Colella and Ms. Mettler-LaFeir:

On December 3, 2019, Danskammer Energy, LLC (the Applicant or Danskammer) submitted a Clean Air Act Title V air permit modification application (Title V Application) to the New York State Department of Environmental Conservation (Department or DEC). Danskammer is seeking authorization to construct and operate a new natural gas-fired combined-cycle power generation facility having an optimal capacity of 536 net megawatts (MW) (the Project) at the current site of its existing 532 MW [nameplate capacity] generating facility (Danskammer Generating Station) located in the Town of Newburgh, Orange County, New York.

The Department has reviewed information submitted by Danskammer, including in the initial Title V Application as well as in its application to the New York State Board on Electric Generation Siting and the Environment (Siting Board) pursuant to Article 10 of the Public Service Law (PSL) (Article 10), and supplemental materials submitted in response to three Notices of Incomplete Application (NOIA) issued by the Department (collectively, the Application). Lastly, the Department has also reviewed the over 4,500 public comments it received during the public comment period.[1]

[1] The Department received over 4,500 public comments from individuals or organizations during the public comment period on the Title V Application, which ran from June 30, 2021 through September 13, 2021.

As described further below, and as initially indicated by the Department in the Notice of Complete Application,[2] the Project would be inconsistent with or would interfere with the attainment of the Statewide greenhouse gas (GHG) emission limits established in Article 75 of the Environmental Conservation Law (ECL).[3] Moreover, Danskammer has not demonstrated that the Project is justified as it has failed to show either a short term or long term reliability need for the Project. Nor has Danskammer identified adequate alternatives or GHG mitigation measures. Accordingly, given that the Department is unable to satisfy these elements required by Section 7(2) of the Climate Leadership and Community Protection Act (CLCPA or Climate Act),[4] the Department is compelled to deny the Title V Application.[5] As required by Title 6 of the New York Codes, Rules, and Regulations (6 NYCRR) Section 621.10, a statement of the Department's basis for this permit denial is provided below.

I. PROCEDURAL BACKGROUND ON TITLE V APPLICATION

In addition to a Title V permit from the Department, pursuant to Article 10, the Project requires a Certificate of Environmental Compatibility and Public Need (Certificate) from the Siting Board. The Project is subject to review under Article 10 by the Siting Board pursuant to a separate parallel administrative proceeding.

In conjunction with its Title V Application, Danskammer filed an application with the Siting Board pursuant to Article 10. On February 10, 2020, John Rhodes, then-Chairman of the Siting Board, sent a letter to the Applicant identifying a number of deficiencies in the Article 10 application. Thereafter, Danskammer filed four supplements to its Article 10 application with the Siting Board on March 11, April 21, July 8, and November 18, 2020. On February 26, 2021, then-Chairman Rhodes advised the Applicant that the Article 10 application, as supplemented, was compliant with PSL § 164, thereby commencing the Siting Board's one-year Article 10 public review process.[6] Separate and apart from the Department's obligation to apply the Climate Act in reviewing the Title V Application, the Project's consistency with the Climate Act, including the GHG emissions associated with the Project and the potential need for the Project, is also an issue for resolution before the Siting Board. Given that a Title V air permit from DEC is a prerequisite for the Siting Board to issue an Article 10 Certificate for the Project, the Siting Board will be unable to issue an Article 10 Certificate as a result of the Department's action herein.[7]

Contemporaneously with, but independent from, its Article 10 application to the Siting Board, the Applicant submitted, among other things, the Title V Application to DEC on December

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[2] Notice of Complete Application, June 30, 2021 (Complete Notice), Available at: https://www.dec.ny.gov/enb/20210630_reg3.html (last visited October 27, 2021).

[3] ECL § 75-0107(1). *See also* 6 NYCRR Part 496, Statewide Greenhouse Gas Emission Limits.

[4] Chapter 106 of the Laws of 2019.

[5] 6 NYCRR § 621.10(f) ("An application for a permit may be denied for failure to meet any of the standards or criteria applicable under any statute or regulation pursuant to which the permit is sought"). Danskammer's other applications to the Department regarding the Project – including for a State Pollutant Discharge Elimination System (SPDES) permit modification and a Clean Air Act Title IV permit – remain pending before the Department and are not addressed herein.

[6] *See* Application of Danskammer Energy, LLC for a Certificate of Environmental Compatibility and Public Need Pursuant to Article 10 for Approval to Repower its Danskammer Generating Station Site Located in the Town of Newburgh, Orange County, Siting Board Case No. 18-F-0325.

[7] PSL § 172(1).

3, 2019. The Project cannot be constructed or operated without a valid Title V air permit issued by DEC, and the Title V air permit must be issued by DEC prior to the Siting Board's issuance of an Article 10 Certificate. *See* PSL §§ 168(3)(e) and 172(1); *see also* ECL Articles 19, 70 and 75; and 6 NYCRR Parts 200 – 317, 496, and 621.

On January 31, 2020, DEC issued a NOIA (First NOIA) to the Applicant identifying a number of items which required additional information, including information related to the Project's consistency with the CLCPA, to be furnished in support of the Title V Application in order for DEC to determine the Title V Application complete pursuant to DEC regulations. *See* 6 NYCRR Part 621.Among other things, the First NOIA sought from Danskammer "an assessment of how the issuance of a Title V permit modification by the Department would be consistent with the [Statewide] greenhouse gas emission limits established in Article 75 of the [ECL], as required by Section 7(2) of the [Climate Act]."

On February 13, 2020, the Applicant provided DEC with a partial response to the First NOIA. And on July 8, 2020, the Applicant provided DEC with additional information in response to the First NOIA addressing the Project's purported consistency with the CLCPA. In particular, the Applicant submitted a "Supplemental Greenhouse Gas Analysis of the Danskammer Energy Center," prepared by its consultant ICF (the Danskammer July 2020 GHG Supplement).

On August 18, 2020, DEC requested the Applicant to provide additional air pollution modeling information in support of the Title V Application. Following this request, on September 8, 2020, DEC issued a second NOIA to the Applicant on its Title V Application and identified items which required additional information, including information related to the Project's consistency with the CLCPA (Second NOIA), for DEC to continue its review. The Second NOIA requested additional information from the Applicant related to the Danskammer July 2020 GHG Supplement and, among other items, specifically sought information regarding: (1) "direct GHG emissions from the facility itself, as well as upstream GHG emissions associated with the extraction and transmission of the natural gas to be combusted at the facility"; and (2) "the feasibility of utilizing renewable natural gas (RNG), including analysis to support the assumption that all combustion of RNG would result in zero on-site GHG emissions."

On November 17, 2020, the Applicant submitted additional information in response to DEC's August 18, 2020 request for information and the Second NOIA, which included an ICF-prepared supplement to the Danskammer July 2020 GHG Supplement (collectively, the Danskammer November 2020 GHG Supplement).

Finally, on January 19, 2021, DEC issued a third NOIA to the Applicant on its Title V Application and identified items which required additional information for DEC to continue its review and assess the Project's consistency with the Climate Act (Third NOIA).[8] In particular, the Third NOIA requested data on projected Nitrogen Dioxide (NO_2) emissions as well as alternative plans to address an event where not all RNG needed for the Project could be obtained. On February 9, 2021, the Applicant and ICF submitted additional information to DEC in response to the Third

[8] On January 26, 2021, the Siting Board issued a letter indicating that the Applicant had agreed to a four-week extension of the Article 10 deficiency review as of January 19, 2021 – the same date as DEC's Third NOIA to the Applicant on its Title V Application.

NOIA, further supplementing the Title V Application (collectively, the Danskammer February 2021 GHG Supplement).

Pursuant to DEC regulations, DEC would have had until April 9, 2021 to determine whether the Applicant's Title V Application was complete. *See* 6 NYCRR § 621.6. As noted, DEC's three separate NOIAs issued to the Applicant focused almost exclusively upon the Project's compliance with the Climate Act because compliance with the Climate Act is a key requirement of DEC's Title V air permit determination. *See* CLCPA § 7.

On April 8, 2021, the Applicant submitted a letter to DEC agreeing to a two-month (60 day) extension to June 8, 2021 for DEC to determine whether the Applicant's Title V Application was complete. On June 8, 2021, the Applicant submitted a letter to DEC agreeing to an additional two-week (14 day) extension to June 22, 2021 for DEC to determine whether the Applicant's Title V Application was complete. On June 21, 2021, the Applicant submitted a letter to DEC agreeing to an additional nine (9) day extension to June 30, 2021 for DEC to determine whether the Applicant's Title V Application was complete.

On June 30, 2021, DEC tentatively determined the Applicant's Title V Application, among others, "complete" for purposes of 6 NYCRR Part 621 and published for review and comment a draft Title V air permit for the Project in the Department's Environmental Notice Bulletin (ENB) for a 60-day time period.[9] As noted above, the Department explicitly indicated at the time of public notice that the Project, as proposed, was inconsistent with the requirements of the Climate Act. As a result of heightened public interest in the draft permits noticed for the Project, the public review and comment period was subsequently extended by an additional fifteen (15) days to September 13, 2021.

On August 23 and 25, 2021, DEC's Office of Hearings and Mediation Services (OHMS) conducted a total of four (4) separate virtual public legislative hearings held pursuant to 6 NYCRR Part 621 to receive statements from members of the public on the draft permits for the Project. OHMS conducted the hearings virtually due to ongoing concerns with COVID-19 infection and transmission in the county where the Project is proposed to be located. A total of 195 individuals provided oral statements at the four (4) public legislative hearings.

The Department's public comment period on the draft permits for the Project closed on September 13, 2021. As of that date, DEC received more than 4,500 separate and timely-filed written public comments on the draft permits; DEC also received about 20 separate written comments on the draft permits after the public comment period closed.

II. BASIS FOR DENIAL OF TITLE V APPLICATION

The Department has completed its review of information submitted by the Applicant, specifically the Application, which includes the initial Title V Application and each of the supplemental materials submitted in response to the NOIAs subsequently issued by DEC, as well as the Article 10 application and public comments. As detailed further below, the Project would

[9] *See* Complete Notice. In addition to a draft Title V air permit, DEC also published a draft SPDES permit for the Project in the ENB on June 30, 2021.

be inconsistent with or would interfere with the attainment of the Statewide GHG emission limits established in Article 75 of the ECL.[10] Consequently, in light of the requirements of Section 7(2) of the Climate Act,[11] the Department has made a determination to deny the Title V Application. 6 NYCRR § 621.10(f).

a. General Climate Act Requirements

The Climate Act, effective January 1, 2020, establishes economy-wide requirements to reduce Statewide GHG emissions. Article 75 of the ECL establishes Statewide GHG emission limits of 40% below 1990 levels by 2030, and 85% below 1990 levels by 2050.[12] As set forth in the Climate Act, Statewide GHG emissions include all emissions of GHGs from anthropogenic sources within the State, as well as upstream GHGs produced outside of the State associated with either: (1) the generation of electricity imported into the State; or (2) the extraction and transmission of fossil fuels imported into the State.[13] In the case of a fossil fuel-fired electric generating facility such as the proposed Project, this includes the upstream GHG emissions associated with the production and transmission of the natural gas or other fossil fuel to be combusted at the facility.

As required by the Climate Act,[14] on December 30, 2020, the Department finalized its regulation to translate these statutorily required Statewide GHG emission percentage reduction limits into specific mass-based limits, based on estimated 1990 GHG emission levels.[15] Pursuant to 6 NYCRR Part 496, the 2030 and 2050 Statewide GHG emission limits are, respectively, 245.87 and 61.47 million metric tons of carbon dioxide equivalents (CO_2e), measured on a 20-year Global Warming Potential (GWP) basis.[16]

CO_2e provides a measure of the relative GWP of each individual type of GHG to that of carbon dioxide (CO_2) over a specific time frame. CO_2 is assigned a value of one (1) and all other GHGs have a GWP greater than that of CO_2 when measured on a pound-for-pound basis. For example, the GWP of methane on a 20-year basis (GWP20) is defined in 6 NYCRR Part 496 as 84, meaning that one ton of methane emissions has the same global warming impact as 84 tons of CO_2. Equating the GWP of various GHGs to that of CO_2 provides a uniform basis for the analysis of the relative climate impact of different compounds. The GWP of a compound is also dependent on the timeframe used for measurement. Under the Climate Act, as required by ECL Article 75, GHGs must be measured using GWP20, rather than the one-hundred-year timeframe (GWP100) most typically used by the federal government and the United Nations.[17] The CO2e, using GWP20, of each GHG under the Climate Act is listed in a table in the Department's regulations at 6 NYCRR Section 496.5.

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[10] ECL § 75-0107(1). *See also* 6 NYCRR Part 496, Statewide Greenhouse Gas Emission Limits.
[11] Chapter 106 of the Laws of 2019.
[12] ECL § 75-0107.
[13] ECL § 75-0101(13).
[14] ECL § 75-0107(1).
[15] *See* 6 NYCRR Part 496, Statewide GHG Emission Limits.
[16] 6 NYCRR § 496.5.
[17] ECL § 75-0101(2).

In addition to these Statewide GHG emission reduction requirements established in the ECL and particularly relevant for this proposed Project, the Climate Act includes a new PSL Section 66-p. This provision requires the Public Service Commission (PSC) to implement programs to ensure that, subject to certain limited exceptions, 70% of electricity is renewable by 2030 and all electricity generation in the State is emission-free by 2040.[18] In addition to the currently effective requirements of Section 7, the Climate Act also established the Climate Action Council, which is currently developing a Scoping Plan that will provide recommendations for how the State will achieve the Statewide GHG emission limits as well as net zero GHG emissions by 2050.[19] Finally, by January 1, 2024, the Department must promulgate substantive and enforceable regulations on all GHG emission sources that reflect the Scoping Plan recommendations and ensure compliance with the Statewide GHG emission limits.[20]

b. Requirements of Section 7(2) of the Climate Act

While the State is currently in the process of implementing the CLCPA, including through the development of the Scoping Plan and regulations described above, the requirements of Section 7 of the Climate Act, as noted, are already in effect and applicable to Danskammer's Title V Application for the Project. Among other requirements, the Department cannot issue a Title V permit to Danskammer for the Project, unless the Department can ensure compliance with all requirements of CLCPA Section 7.

Section 7(2) of the Climate Act has three elements.[21] First, as is relevant here for purposes of the Department's review of the Title V Application, the Department must consider whether a Title V permit for the Project would be inconsistent with or interfere with the attainment of the Statewide GHG emission limits established in ECL Article 75. Second, if the issuance of a Title V permit for the Project would be inconsistent with or would interfere with the Statewide GHG emission limits, then the Department must also provide a detailed statement of justification for the Project notwithstanding the inconsistency. Third, in the event a sufficient justification is available, the Department must also identify alternatives or GHG mitigation measures to be required for the Project.

As the Department initially indicated in the Complete Notice, there are substantial GHG emissions associated with the Project. Based on the information available at the time of the Complete Notice, the Department indicated that it appeared that the proposed Project would be inconsistent with or would interfere with the attainment of the Statewide GHG emission limits established in ECL Article 75.[22] Similarly, based on the information provided to that point, the Department noted that it was not currently able to satisfy either of the other two elements of Section 7(2) with respect to the proposed Project – that is, (1) a detailed statement of justification notwithstanding the inconsistency; and (2) alternatives or GHG mitigation measures to be required.

[18] PSL § 66-p(2).
[19] ECL § 75-0103.
[20] ECL § 75-0109.
[21] In addition to the requirements of CLCPA Section 7(2) regarding consistency with the Statewide GHG emission limits, prior to issuing any Title V permit or other permit for the Project, the Department would also need to ensure compliance with the requirements of Section 7(3) of the Climate Act with respect to potential disproportionate impacts on disadvantaged communities.
[22] Complete Notice; ECL Article 75; 6 NYCRR Part 496.

Since the time of the Complete Notice, the Department has not received any information from Danskammer or otherwise that alters these preliminary conclusions.

c. <u>Determination of Inconsistency</u>

Based on the information available in the Application, which includes the responses to DEC's three separate NOIAs as submitted by the Applicant, the Department hereby determines that the Project as proposed would be inconsistent with or would interfere with the attainment of the Statewide GHG emission limits established in Article 75 of the ECL.

This determination of inconsistency is based primarily on the fact that the Project would be a new source of a substantial amount of GHG emissions, including both direct and upstream GHG emissions, and that the Project would constitute a new and long-term utilization of fossil fuels to produce electricity without a specific plan in place to comply with the requirements of the Climate Act.[23] On the other hand, Danskammer's assertions of compliance with the Climate Act are based on electricity sector modeling projections that are uncertain and that rely on potential reductions in GHG emissions at other facilities. As explained further below, this alone is insufficient to determine consistency with the Statewide GHG emissions limits under the Climate Act.

i. <u>Direct GHG Emissions</u>

First, as acknowledged in the Title V Application, the Project would result in significant direct GHG emissions. According to Danskammer's Title V Application, the Project's overall potential to emit (PTE) GHGs would be 1,954,952 short tons of CO_2e per year utilizing a GWP100.[24] By any metric, this is a substantial amount of potential direct GHG emissions from a new source in the State. An *increase* of this amount due to this one new fossil fuel-fired power plant project is inconsistent with the achievement of the Statewide GHG emission limit for 2030, or at a minimum would interfere with the attainment of such Statewide GHG emission limit, especially given that achieving such limit requires a substantial overall *reduction* in GHG emissions.

The Applicant also included other direct GHG emission figures in the Application. For example, for purposes of the Prevention of Significant Deterioration/Nonattainment New Source Review (PSD/NNSR) Netting Analysis and the calculation of Emission Reduction Credits, Danskammer provided a baseline actual GHG emission figure. This provides actual GHG emissions from the existing facility located at the site of the proposed Project. Danskammer calculated baseline actual GHG emissions of 47,304 short tons of CO_{2e} per year (GWP 100) from the existing facility.[25] By subtracting this amount from the Project's PTE for GHGs, the Applicant calculated a Project net GHG emissions increase of 1,907,648 short tons of CO_2e per year.[26]

[23] Ch. 106 of the Laws of 2019.
[24] Title V Application. Table 2-1, pp. 2-8. Notably, this CO_2e figure is based on GWP100 values, rather than the GWP20 values required by the Climate Act and included in 6 NYCRR Part 496. Thus, the GHG PTE of the Project would be even higher if measured using the required GWP20 values set forth in 6 NYCRR Part 496.
[25] Title V Application, Table 3-4, pp. 3-24.
[26] *Id.* As previously noted, this calculation utilizations GWP100 values for CO_2e as required for purposes of PSD/NNSR, rather than the GWP20 values required by the Climate Act and set forth in 6 NYCRR Part 496.

In addition, in the Danskammer November 2020 GHG Supplement, the Applicant included different estimates for the increase in direct GHG emissions in the State from electric generation by the Project. Unlike the PTE figures noted above, these estimated amounts are based on the projected dispatch of the new facility over time. According to the Applicant, the Project would not be expected to operate one hundred percent of the time, but Danksammer and ICF projected that the Project would have a much higher capacity factor than the existing facility located at the Project site. Based on projected dispatch of the Project, according to Danskammer, the increase in direct GHG emissions from the Project is projected to be 1.577 million short tons of GHGs per year in 2025, 1.085 million in 2030, and 1.104 million in 2035.[27]

The Department is not able to, nor does it need to, address or evaluate all of the methodological assumptions or analytical decisions made by Danskammer or ICF for purposes of their own estimates of GHG emissions from the Project. Moreover, as estimated by the Applicant, there is a range of estimates of projected GHG emissions from the Project. Generally speaking, PTE is calculated by assuming that a facility operates at its maximum capacity 24 hours per day, 365 days per year, whereas projected actual GHG emissions reflect a facility's expected hours of operation considering any planned downtime for maintenance or other periods where the facility's capacity may be reduced from its design maximum. Thus, as stated by Danskammer in its Application, direct GHG emissions from the Project in 2030 may range from 1.085 million short tons of CO_2e (GWP20) to 1.955 million short tons of CO_2e (GWP100). Regardless of where in this range GHG emissions ultimately fall, this would constitute a substantial and direct source of new GHG emissions in the State. As a result, even before considering the other issues noted below, the Project is inconsistent with or would interfere with the attainment of the Statewide GHG emission limit for 2030, as established by ECL Article 75 and reflected in 6 NYCRR Part 496.

ii. Upstream GHG Emissions

Importantly, this substantial amount of GHG emissions only includes the direct GHG emissions from on-site fossil fuel combustion at the Project. In other words, it is before even considering the upstream GHG emissions associated with the extraction and transmission of the fossil fuels to be combusted at the Project. As indicated above, upstream out-of-state GHG emissions associated with such fossil fuel imports are considered part of Statewide GHG emissions under the Climate Act.[28] Therefore, such GHG emissions must be considered by the Department for the Project pursuant to Section 7(2) of the Climate Act. Moreover, pursuant to the Climate Act, GHG emissions must be calculated using a GWP20 for CO_2e.[29]

In response to the First NOIA and the Second NOIA, the Applicant provided estimates of upstream GHG emissions associated with the Project. The Danskammer November 2020 GHG Supplement estimated an increase of 476,000 short tons of GHGs (using GWP20 for methane) in 2030 attributable to the upstream GHG emissions from generation by the Project.[30] This estimate

[27] Danskammer November 2020 GHG Supplement, Table 2-3, p. 6.
[28] ECL § 75-0101(13).
[29] ECL § 75-0101(2).
[30] Danskammer November 2020 GHG Supplement, Table 2-3, p. 6.

is based on Danskammer and ICF's projected dispatch of the Project and does not correspond to the full PTE provided in the initial Title V Application. In other words, if the Project were to operate more frequently than projected by Danskammer and ICF, then the upstream GHG emissions associated with the Project would increase accordingly.

Just as with direct GHG emissions from on-site combustion, the upstream GHG emissions associated with the Project are substantial. Even presuming the Applicant and ICF's projections of upstream GHG emissions are correct, 476,000 additional short tons of GHG emissions in 2030 from a new facility like the Project would be inconsistent with or would interfere with the attainment of the Statewide GHG emission limit for 2030, as established by ECL Article 75 and reflected in 6 NYCRR Part 496.

iii. Total Project GHG Emissions

To determine the total amount of GHG emissions attributable to the Project, the upstream GHG emissions need to be added to the direct GHG emissions from the Project. Thus, according to the Applicant, total GHG emissions from the Project would be between 1.561 and 2.4231 million short tons of CO_2e in 2030.

By any metric, but particularly under the Climate Act, the range of estimated GHG emissions from the Project provided by the Applicant represents a substantial amount of GHG emissions. While achieving the Statewide GHG emissions limits requires an overall *reduction* in GHG emissions from current levels, the Project itself would result in a substantial *increase* in GHG emissions from just this one single GHG emission source in 2030.[31] Moreover, the Project would constitute a wholly new and fossil fuel-fired electric generation source. Therefore, the Project would make meeting the Statewide GHG emission limits established in ECL Article 75 substantially more difficult. Thus, under Section 7(2) of the Climate Act, the issuance of a Title V permit for the Project would be inconsistent with or would interfere with the attainment of the Statewide GHG emission limits.

iv. New and Long-term utilization of Fossil Fuel

In addition to the substantial GHG emissions from the Project, the Project is also inconsistent with other longer-term requirements of the Climate Act, given that it would be a new facility which would use fossil fuels to produce electricity. To achieve the State's climate change and clean energy policies as outlined in the CLCPA, the State needs to continue to accelerate its ongoing transition away from natural gas and other fossil fuels. Constructing and operating a new fossil fuel-fired power plant accomplishes the exact opposite and perpetuates a reliance on fossil fuels. As explained above, in addition to the Statewide GHG emission reduction requirements established in ECL Article 75, the Climate Act includes a requirement that all electricity in the

[31] Title V facilities are required to report annual actual emissions of various air contaminants to the Department on an annual basis. This information is used to prepare an inventory of Statewide emissions for program planning and other purposes. The most recent complete inventory available is based on 2019 emissions data. Comparing the reported 2019 emissions data for other electric generating facilities to the projections prepared by Danskammer for the Project suggests that the Project would be among the highest GHG emitting electric generating facilities in the State.

State be emissions-free by 2040.[32] The continued long-term use of fossil fuels to produce electricity – as proposed by Danskammer for the Project – is inconsistent with the State's laws and objectives, including the statutory requirement that all electricity in the State be emission-free by 2040.[33]

In other words, subject to certain limited exceptions, none of which are applicable here, the Climate Act contains a statutory mandate to ultimately cease the use of fossil fuels to produce electricity in the State by 2040. Particularly in the absence of any justification for the Project or the identification of alternatives or appropriate GHG mitigation measures, a new fossil fuel-fired electric generation facility like this Project could exacerbate and extend the use of fossil fuels to produce electricity, contrary to the requirements of the Climate Act. In this manner, the Project would delay, frustrate, or increase the cost of the statutorily mandated transition away from the use of natural gas and other fossil fuels to produce electricity in the State. The construction of a new fossil fuel-fired major electric generation facility, which would otherwise be expected to have a useful life beyond 2040, is inconsistent with the CLCPA's requirement for emission-free electricity generation by 2040.[34]

v. Emission-Free by 2040 Requirement

In its Application, Danskammer recognizes the emission-free electricity generation by 2040 requirement, but acknowledges that it is "not proposing any specific approach at this time" to meet the CLCPA's emission-free electricity by 2040 requirement.[35] The Applicant provides several potential options for how it might meet this requirement in the future, including: (1) converting the Project to utilizing hydrogen or RNG, if such fuels are available in sufficient quantities and deemed to be zero emission fuels under the Climate Act; (2) continuing to operate to the extent authorized by PSC under the CLCPA; or (3) other solutions that are not currently identifiable.[36] Only if these options are not feasible might the Applicant shut down the Project.

Overall, the Applicant's plan for compliance with the Climate Act's emission-free by 2040 generation requirement is uncertain and speculative in nature. With respect to the first potential compliance pathway – utilizing RNG or hydrogen as a potential compliance pathway – Danskammer has not established its feasibility from either a supply or GHG emission perspective.

For example, there is uncertainty surrounding the feasibility of firing hydrogen in existing combustion turbines. Nascent testing of hydrogen combustion at certain facilities is partially intended to address some of this uncertainty. While existing combustion turbines are generally capable of firing mixtures of hydrogen and natural gas, these fuel blends raise other concerns. When compared to natural gas, hydrogen has a higher explosive potential, a higher leak potential, a lower volumetric heating value, and a higher flame temperature. A lower volumetric heating

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[32] PSL § 66-p.
[33] *Id.*
[34] *See also* DEC Notice of Denial of Water Quality Certification, Northeast Supply Enhancement Project, May 15, 2020, at pp. 14-16, Available at: https://www.dec.ny.gov/docs/permits_ej_operations_pdf/nesewqcdenial05152020.pdf (last visited October 27, 2021).
[35] Danskammer November 2020 GHG Supplement, p. 4.
[36] *E.g.*, Danskammer February 2021 GHG Supplement.

value means that more fuel needs to be fired to achieve the same output. The additional volume of fuel fired, combined with the higher flame temperature when firing hydrogen, is expected to cause higher emissions of Oxides of Nitrogen (NOx) without the installation of additional NOx controls. An existing combustion turbine facility may be required to modify its fuel feed system, fuel firing system, and/or emission control system to facilitate hydrogen firing in the combustion turbine while maintaining compliance with its permitted emission limits. Further, if a blend of hydrogen and natural gas is combusted, some amount of GHG emissions would still be generated from the natural gas component of the fuel mixture, potentially jeopardizing the facility's compliance with the zero emissions by 2040 requirement in the CLCPA.

With respect to RNG, while it may be technically feasible to operate the Project on RNG, Danskammer, in the ICF report, acknowledges that a transition to RNG is predicated on the availability of RNG in existing pipeline infrastructure by 2040.[37] For this capacity to be realized, third parties would need to pursue approval for the necessary infrastructure to generate and deliver RNG in sufficient quantities to allow the Project to continue to operate. That approval process – which would likely also be subject to Section 7(2) of the Climate Act by the relevant agency or agencies – may affect the ability to commence construction and operation on a schedule that meets the needs of the Project. Further, neither the Department, the Siting Board, nor the PSC have yet determined the extent to which RNG combustion may be an acceptable means of meeting the zero-emission by 2040 requirement of the CLCPA.

The other two options – continuing to operate based on approval by the PSC or some other solution that is not currently identifiable – are indeterminate and rely on potential future action by PSC or additional developments. Regardless, at this time, Danskammer is not specifically proposing to transition to either hydrogen or RNG. While the Application discusses and assumes that the Project will ultimately transition to hydrogen or RNG, these are essentially aspirational references, as the Application at issue before the Department here contemplates firing fossil fuels at the Project. While the overall implementation of the Climate Act by the State is ongoing and some details may be uncertain, it is already clear that the construction and operation of a new fossil fuel-fired power plant is inconsistent with the Climate Act, unless an adequate justification, assessment of alternatives, and GHG mitigation are provided.

vi. Projected Displacement of Other Electric Generation

The Applicant's assertions that the Project would be consistent with the Climate Act are primarily based on the projected displacement of other less efficient and higher emitting electric generation sources. In other words, while the Application describes substantial direct and upstream GHG emissions attributable to the Project itself, the Applicant also claims that other electric generation sources in the State would reduce GHG emissions by an even greater amount once the Project is operating. Thus, the Applicant relies upon projected actions at other locations by owners and operators of other electric generation sources to reduce the GHG impact of its facility, rather than specifically addressing the GHG emissions directly attributable to the Project or Danskammer.

[37] Danskammer November 2020 GHG Supplement, pp. 8-9.

The purported displacement of less efficient fossil fuel generators by the Project is based on electricity sector modeling performed for the Applicant by ICF. As with any such electricity sector modeling, its outputs are largely determined by chosen inputs and assumptions. The Department cannot address or evaluate all the methodological assumptions or analytical decisions made by Danskammer or ICF for purposes of their own estimates of GHG emissions associated with the Project. The Department will not rely exclusively on such electricity sector modeling for purposes of assessing compliance with Climate Act Section 7(2). Electricity sector modeling, particularly to the extent it is utilized to project GHG emission from sources other than the Project at issue here, may not provide the level of precision necessary to serve as the primary basis for the Department to determine consistency with the Climate Act.

The fact that chosen assumptions used in electricity sector modeling can drastically change its results is illustrated by the fact that the Applicant itself initially projected the operation of the Project would result in Statewide GHG emission *increases* in 2030. The Applicant's own analysis initially projected that, in 2030, the Project would result in 191,000 short tons of additional direct CO_2 emissions in the State, along with 84,000 short tons of CO_2e of additional upstream GHG emissions associated with the Project.[38] Only after DEC's Second NOIA did Danskammer update its modeling analysis such that the November 2020 GHG Supplement projected Statewide GHG emission *decreases* in 2030.

In the case of a new fossil fuel-fired electric generation facility, the projected displacement of other less-efficient and higher-emitting electric generating units is not a sufficient basis to determine consistency with the Statewide GHG emission limits established in ECL Article 75 pursuant to CLCPA Section 7(2). The Project itself would result in substantial direct and upstream GHG emissions due to the production, transmission, and combustion of fossil fuels. The extent to which the Project might displace other electric generating units is uncertain and dependent upon a number of factors that are not fully controlled by Danskammer, including the relative dispatch of the Project and other sources, as well as future market conditions. Regardless, Climate Act Section 7(2) requires the Department to make a determination in the context of a permitting action for an individual facility. As part of this review, because the Department is taking action with respect to one particular source – in this case, the Project – the Department does not specifically take into account actions that may or may not occur at other GHG emission sources. Other GHG emission sources are generally subject to requirements pursuant to separate Departmental permits and may require their own reviews pursuant to Section 7(2) of the Climate Act.

Overall, because it is at best uncertain whether the Project would actually displace other electric generation sources to the extent necessary to offset the direct and upstream GHG emissions attributable to the Project, the projected displacement of other electric generation is not a sufficient basis to determine consistency for a new fossil-fuel fired electric generation facility like the Project.

vii. Project Need and Justification

As indicated above, a determination of inconsistency is only the first of three elements required pursuant to Section 7(2) of the Climate Act. That is, when, as here, a permit decision

[38] Danskammer July 2020 GHG Supplement, Tables 4-4 and 4-5, pp. 20-21.

would be inconsistent with or would interfere with the Statewide GHG emission limits established in ECL Article 75, the agency must also: (1) provide a detailed statement of justification notwithstanding the inconsistency; and (2) if such a justification is available, identify alternatives or GHG mitigation measures to be required. Thus, in order to ensure compliance with the Climate Act, the Department must address these two additional elements as part of its determination on the Title V Application for the Project.

Danskammer has not offered a sufficient basis for the Department to justify the Project notwithstanding its inconsistency with the Statewide GHG emission limits established in ECL Article 75 and the Climate Act. However, based upon publicly available studies and reports by the New York Independent System Operator (NYISO), any previous reliability deficiency has been resolved. Therefore, at least through 2030, there is no demonstrated reliability need or justification for the Project.

In New York State, NYISO studies and evaluates the long-term reliability needs of the State. In order to evaluate State reliability needs, NYISO has a Comprehensive Reliability Planning Process comprised of four components: (1) the Local Transmission Planning Process; (2) the Reliability Planning Process (RPP) along with parts of the Short Term Reliability Process; (3) the Congestion Assessment and Resource Integration Study; and (4) the Public Policy Transmission Planning Process. Under the RPP, NYISO conducts a Reliability Needs Assessment (RNA), which is a biennial study that evaluates the resource adequacy and transmission system security of New York's bulk power transmission facilities.

NYISO published its last RNA report in 2020, which covers the study period years 2024 through 2030.[39] The 2020 RNA initially found loss of load expectation (LOLE) violations occurred in years 2027 through 2030 of the study period. The identified deficiencies were driven by the compound effect of the increasing load forecast and loss of generation in Zone J (New York City). The 2020 RNA found that potential solutions to address the identified resource deficiency in Zone J could include a combination of increased transfer capability into Zone J, increased resources located within Zone J, or demand-side solutions.

The deficiencies identified in the 2020 RNA were resolved by the post-RNA Base Case updates as identified by NYISO in early 2021. These updates included a reduced peak load forecast in Zone J, decreasing peak load by 392 MW in 2030, updates submitted by Con Edison to its Local Transmission Plan, and operation procedures.[40] With these updates and resolved deficiencies, according to NYISO, up to 800 MW in zonal capacity can be removed from Zone G – where the Project is to be located – in 2030 without causing any LOLE violations.[41] As indicated above, the existing electric generating facility at the site of the Project has a capacity of 532 MW, while the proposed Project would have a capacity of 536 MW. Consequently, there is no demonstrated reliability need or justification for the Project.

[39] NYISO 2020 RNA, Available at: https://www.nyiso.com/documents/20142/2248793/2020-RNAReport-Nov2020.pdf/64053a7b-194e-17b0-20fb-f2489dec330d (last visited October 27, 2021).
[40] NYISO Reliability Planning Process, Post-RNA Base Case Updates, February 23, 2021 Presentation, slide 13, Available at: https://www.nyiso.com/documents/20142/19415353/07%202020-2021RPP_PostRNABaseCaseUpdates.pdf/ (last visited October 27, 2021).
[41] *Id.* at slide 16.

viii. GHG Mitigation and Alternatives

Because there is no justification for the Project notwithstanding its inconsistency with the Statewide GHG emission limits established in ECL Article 75, the Department need not reach this element of the Climate Act Section 7(2) analysis. In any case, Danskammer has not proposed any additional GHG mitigation measures pursuant to the CLCPA, beyond those required by other existing regulations.

III. CONCLUSION

For all of the reasons described above, the Department hereby denies the Title V Application for the Project (DEC ID: 3-3346-00011/00017).

Pursuant to 6 NYCRR Section 621.10(a)(2), Danskammer has the right to request an administrative adjudicatory hearing regarding the denial of its Title V Application. Pursuant to this provision, any such request for a hearing must be made in writing within thirty (30) days of the date of this letter.

If you have any questions regarding this denial, you may contact me or Michael Higgins in my office, or Mark D. Sanza, Esq. in the Office of General Counsel. Thank you.

Sincerely,

Daniel Whitehead

Daniel Whitehead, Director
Division of Environmental Permits

cc: M. Keller, TRC
T. Berkman, OGC
M. Sanza, OGC
J. Binder, OGC
M. Higgins, DEP
S. Hagell, OCC
M. Lanzafame, DAR

Appendix Q

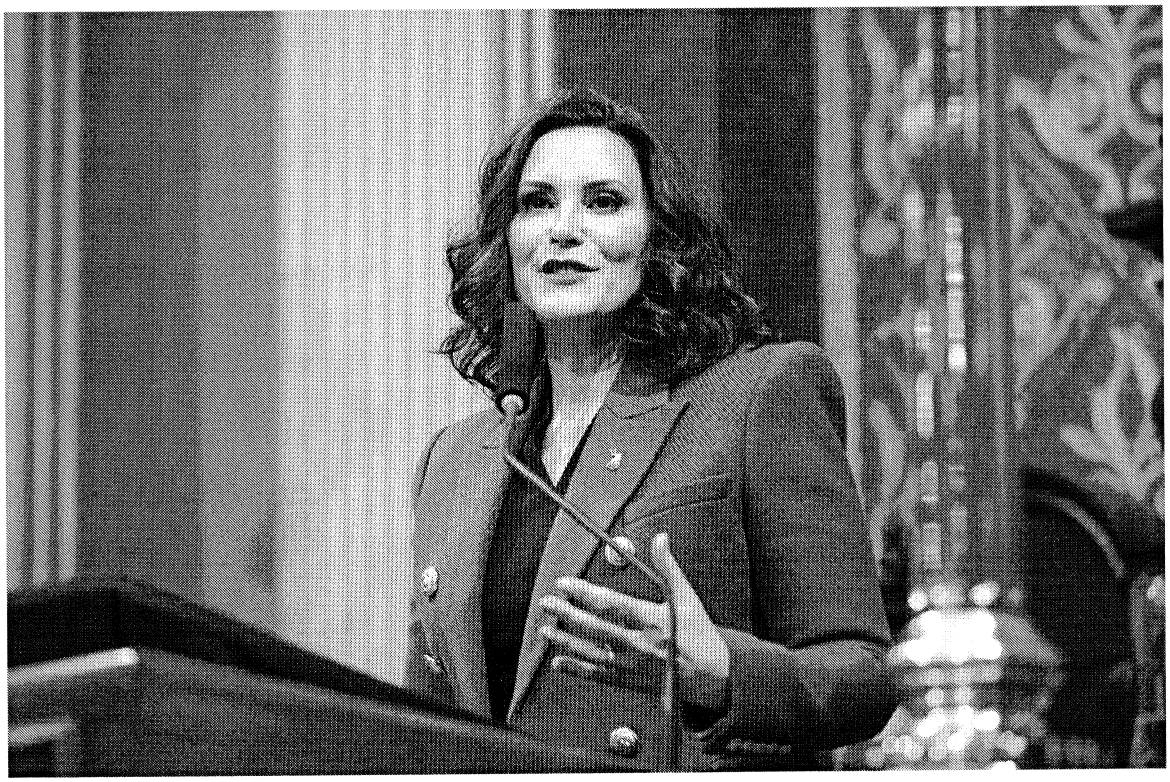
CLIMATEWIRE: Michigan sets deadline to get all power from clean energy [Climate Wire 11/29/23]: Mich. City offers New model for 100% clean power [EEnews 11/5/21]

CLIMATEWIRE

Michigan sets 2040 deadline to get all power from clean energy

Seven climate bills signed Tuesday by Gov. Gretchen Whitmer commits the state to an aggressive timeline to decarbonize electricity.

BY: **ADAM ATON** | 11/29/2023 06:49 AM EST



Michigan Gov. Gretchen Whitmer (D) delivers her State of the State address Jan. 25. | Al Goldis/AP

CLIMATEWIRE | Michigan will require all its electricity to come from "clean energy" by 2040 under a package of climate laws Gov. Gretchen Whitmer signed Tuesday.

Her approval caps a monthslong effort by Michigan Democrats to pass the legislation. And the package of seven climate bills commits Michigan to one of the most aggressive timelines of any state to decarbonize electricity. Utilities will have to source half their power from renewable sources by 2030, rising to 60 percent by 2035.

The new laws empower the Michigan Public Service Commission to bypass local restrictions on building utility-scale renewable energy projects. They also elevate climate and equity in regulatory decisions, incentivize energy efficiency, and create a state office for workers in the energy transition.

The laws are a political triumph for Whitmer. The Democratic governor outlined a climate plan just a few months before the midterms, in which she won reelection and Democrats took narrow majorities in the Michigan Legislature for the first time since the 1980s.

"We've been working toward this day for a long time," Whitmer said at a rally in Detroit before signing the seven climate bills. "Once I sign these bills, Michigan becomes a national leader on clean energy, bringing billions of federal tax dollars home and private investment into our communities."

With almost no room for error, Democrats' climate legislation idled in committee for most of the year while lawmakers tackled issues with more internal consensus, such as abortion rights and LGBTQ+ protections. Some lawmakers worried that a big climate package could cost them support from unions or worsen the cold-weather state's already unreliable grid.

In August, Whitmer gave a speech calling for lawmakers to pass climate legislation, but she didn't wade into specific details. Then, after weeks more of negotiations, Democrats quickly moved the legislation through both chambers. Those bills were among the last to pass the Statehouse before lawmakers adjourned for the year.

"This was a massive undertaking," Whitmer said. "A lot of people doubted we could ever do something like this anywhere in the country — especially in a state like Michigan."

Michigan environmental justice advocates have criticized the clean energy standard because it allows utilities to count biomass, trash incinerators and natural gas with carbon capture toward their clean energy targets. Lawmakers also backed away from their original clean energy goal of 100 percent by 2035.

Big green groups, though, have hailed the entire climate package as a watershed in U.S. climate action. And policy analysts expect the new laws to drive meaningful decarbonization in a heavily industrialized state.

"Michigan is now at the center of the nation's transition to clean energy," said Lisa Wozniak, executive director of the Michigan League of Conservation Voters.

Minnesota, another state where Democrats took total control of state government in 2022, earlier this year enacted a sprawling climate package, including a clean electricity standard mandating carbon-free electricity by 2040.

And states across the country this year have passed clean energy subsidies in hopes of attracting federal funds under the Inflation Reduction Act. The climate package Whitmer signed Tuesday promises to help steer some of that money toward Michigan.

Courtney Bourgoin, Midwest senior policy and advocacy manager at Evergreen Action, said the legislation would "help secure billions of dollars from the Inflation Reduction Act to directly benefit Michigan's businesses, families, and environment for generations to come."

Bills in the climate package are:

- S.B. 271, setting the clean electricity standard.
- H.B. 5120 and H.B. 5121, empowering the Public Service Commission to preempt local restrictions to approve renewable energy projects.
- S.B. 273, incentivizing utilities to reduce energy waste and encourage electrification.
- S.B. 502, directing the Public Service Commission to more fully account for greenhouse gases and environmental justice.
- S.B. 519, creating a Community and Worker Economic Transition Office.
- S.B. 277, codifying solar power generation as a permitted use of farmland.

Michigan Republicans have blasted the climate bills as progressive overreach that will raise prices for electricity and other goods and services.

In a statement to the *Detroit Free Press*, Senate Minority Leader Aric Nesbitt said the new laws amounted to "far-left, unworkable energy mandates that will further increase energy costs and make Michigan energy less reliable."

But that's a fight Democrats are leaning into. Whitmer and other officials have emphasized the new laws' potential to save Michiganders money. During Tuesday's signing ceremony, Whitmer said the new laws would save families an average of $145 a year and create 160,000 jobs.

Almost all of Michigan's fossil fuel-generated electricity is imported from other states, said Martin Kushler, senior fellow with the American Council for an Energy Efficient Economy.

Paying for those fossil fuels means Michiganders are sending billions of dollars each year to other states, he said. By curbing that flow, this package of laws could strengthen the state's economy.

"By increasing energy efficiency and Michigan-based renewable energy, this package of bills will reduce that financial drain and help keep those dollars here in Michigan," Kushler said.

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Mich. city offers new model for 100% clean power

By Jeffrey Tomich | 11/15/2021 07:09 AM EST

In what could be a national model, a Michigan city is aiming to become carbon neutral within a decade even as the state remains tethered to coal and natural gas.

Downtown Ann Arbor, Mich. JuwanGOAT/Wikipedia

When Ann Arbor, Mich., passed a plan a little over a year ago to make the city carbon-neutral by 2030, it meant pivoting as quickly as possible to clean energy, including across the campus of the University of Michigan.

The carbon-neutral goal for the city of 120,000, dubbed A2ZERO, means outpacing Gov. Gretchen Whitmer's (D) plan for the state of Michigan to achieve the same target in 2050. And it means moving faster than Ann Arbor's electricity provider, DTE Electric, which also has a 2050 net-zero emissions target.

So how does a progressive, midsize city go green while the state and the power company remain tethered to coal and natural gas? For Ann Arbor, the answer is: If the monopoly utility won't speed up the energy transition, do it yourself.

The city is looking to compete with DTE by forming what's called a sustainable energy utility, or SEU, a municipal model hatched in academia and first put into practice in Delaware in 2007. The idea is to build a nonprofit, community-based electric company whose mission is to generate renewable power and to conserve energy.

But in this instance, Ann Arbor has a more sweeping concept in mind. The city wants to incorporate battery storage and tie homes and businesses to micro- and nanogrids. The city wants to encourage energy efficiency and the use of geothermal heat pumps as an alternative to heating homes with natural gas. It wants to populate the streets with electric cars.

Ann Arbor wants to reimagine what a local power company can be, as cities increasingly push for more ambitious carbon reductions than the midcentury net-zero emissions goals that have become the language of climate mitigation in America.

"It's a nice sentiment to set goals, but how are we going to achieve them?" said Missy Stults, Ann Arbor's sustainability director.

New models: Minneapolis to Boulder

Ann Arbor has found it difficult to leverage DTE's franchise agreement with the city to meet the type of clean electricity goals adopted by Minneapolis and Boulder, Colo. The reason is a century-old Michigan law that gives DTE a perpetual right to provide the city with electricity.

Yet there's a hitch: DTE's franchise isn't exclusive, which means the city could compete with its incumbent utility.

While building a duplicate distribution grid was a nonstarter, Stults wondered what the city could do without relying on poles and wires.

"With distributed energy resources, I thought maybe this is actually possible. Maybe we could provide a supplemental utility in which we don't actually focus on distribution, or we focus on limited distribution. And instead, we focus on the generation."

The city had local experts work on a technical and legal analysis to determine if it was doable. She said the answer to both questions was "yes."

"What our modeling shows is that it is affordable, at least cost-competitive," she said.

Stults acknowledges there's still a lot of work to be done and questions that need answers, but everything so far points to a parallel utility being a viable pathway for Ann Arbor to meet its climate goals.

To be sure, other cities will be watching.

Ann Arbor is among dozens of U.S. cities of all sizes that are looking to push the pedal on slashing energy sector emissions. While President Biden and Democratic governors, including Michigan's Whitmer, have sought to make addressing climate change a priority, Congress and state legislatures haven't moved as quickly, if at all.

But pledging to transition to 100 percent renewable energy and achieving it on a communitywide basis (versus just city-owned buildings) is easier said than done, said Lacey Shaver, who helps cities meet renewable and decarbonization goals at the World Resources Institute.

In deregulated states such as California, New York and Ohio, cities can choose to buy green energy through community choice aggregation programs. But so-called CCAs aren't allowed in most states, such as Michigan, though Ann Arbor has urged the Legislature to change that.

In fully regulated states, where utilities own the power plants, cities are becoming more actively involved in regulatory proceedings that help determine the electricity fuel mix.

"Cities can really push in these proceedings and try to advance the uptake and saturation of renewables maybe beyond what is the status quo," said Alex Dane, manager of city renewable energy solutions for WRI.

A good example, he said, is Minneapolis, which pushed Xcel Energy Inc. to drop plans for a large new natural gas plant at the site of an existing coal plant outside the Twin Cities. Just this month, Minneapolis also filed comments at the state Public Utilities Commission urging Xcel to deploy battery storage as a substitute for two gas peaking plants that Xcel chose as an alternative.

A small but growing number of cities are also looking to incorporate their clean energy goals and other policy objectives into municipal franchise agreements.

Jeff Cook of the National Renewable Energy Laboratory in Boulder, helped conduct a 2019 national study of utility franchise agreements — contracts that give a utility the right to provide service within a jurisdiction — and how incorporating clean energy goals could help accelerate renewable deployment.

The study found "immense opportunity to leverage franchise agreements to achieve renewable energy objectives," but also that it requires cities and utilities to work together.

"I would argue it is the starting point, it is not an endpoint to achieve these goals," Cook said. "It has been used to foster dialogue, start partnerships and work toward the common end in the context of trying to reach 100 percent renewable goal."

Cook said Minneapolis; Denver; and Sarasota, Fla., are examples of cities that have successfully incorporated their goals into utility franchise agreements. Salt Lake City even worked alongside its utility, Rocky Mountain Power, to get legislation passed.

Generally, renewable energy goals aren't included in utility franchise agreements, but are part of companion agreements. Sometimes cities will commit some part of franchise fees, often a percentage of revenue generated within the city, to achieving clean energy goals.

Some cities have looked at going even further — the municipal takeover.

Often, as in the case of Chicago recently, it doesn't get very far. Taking over a utility's distribution system generally means a long, costly battle as poles, wires, substations and other assets must be acquired through eminent domain proceedings.

The Windy City did a study and found that municipalization would lead to electric rates that were 43 percent higher than they paid incumbent provider Commonwealth Edison Co. Instead, Chicago issued a request for information in April to evaluate alternative electricity providers.

Mayor Lori Lightfoot said the request doesn't mean the city wouldn't negotiate a new franchise agreement with ComEd. Instead, she called it is a "due diligence effort" to get the best deal possible for Chicago residents and the city's policy goals, which include clean energy.

Building a 'parallel utility'

Back in Ann Arbor, Stults, the sustainability director, is focused on the next steps if the city decides to move forward, including figuring out a governance structure and financing. The City Council would also need to pass an ordinance to create the SEU. And if the city is going to incur debt, a vote would be required to authorize it.

The city held a Zoom meeting in early November with interested residents to explain the concept and answer questions.

One interested party with many questions? Detroit-based DTE, which would still own the poles and wires and be responsible to supplying whatever power the Ann Arbor SEU doesn't generate locally.

About half of DTE's electricity supply was generated from coal in 2020, according to the utility, with about 10 percent generated from wind and solar power.

Brian Calka, DTE's director of renewable solutions, said the utility has a long history of working with Ann Arbor and only recently got approval from Michigan regulators to build a 20-megawatt community solar project on a capped landfill site and greenfield site owned by the city.

Calka said the energy produced will be used to help Ann Arbor and a neighboring township meet their renewable energy goals.

DTE and the city have also discussed a much larger solar development: a 440-MW project sized to offset all of Ann Arbor's communitywide energy use, he said.

How, or if, a large solar project fits with the city's vision for a parallel utility is unclear at this point.

Calka said DTE was initially unaware the city was looking at the concept of an SEU. "It caught us by surprise," he said.

Even after the city issued a 40-page report last month, DTE still has unanswered questions. They include whether the utility would be responsible for maintaining enough generation capacity to meet 100 percent of the city's energy needs, and how city-owned generation would interact with DTE's local grid.

"We've been in a phase of trying to better understand some of the finer details of what it means to them and what it means to DTE," Calka said.

Stults said the idea for a parallel utility that would compete with DTE isn't about trying to disrupt a century-old business model. It's about achieving the city's policy goals.

"If our utility offered these services, we wouldn't have to," she said. "If they had the same ambition and the same options on the table as what we're talking about, we wouldn't be having this conversation. So offer what we want, offer it at an affordable price and equitable manner. And maybe we don't have to pursue this."

Appendix R

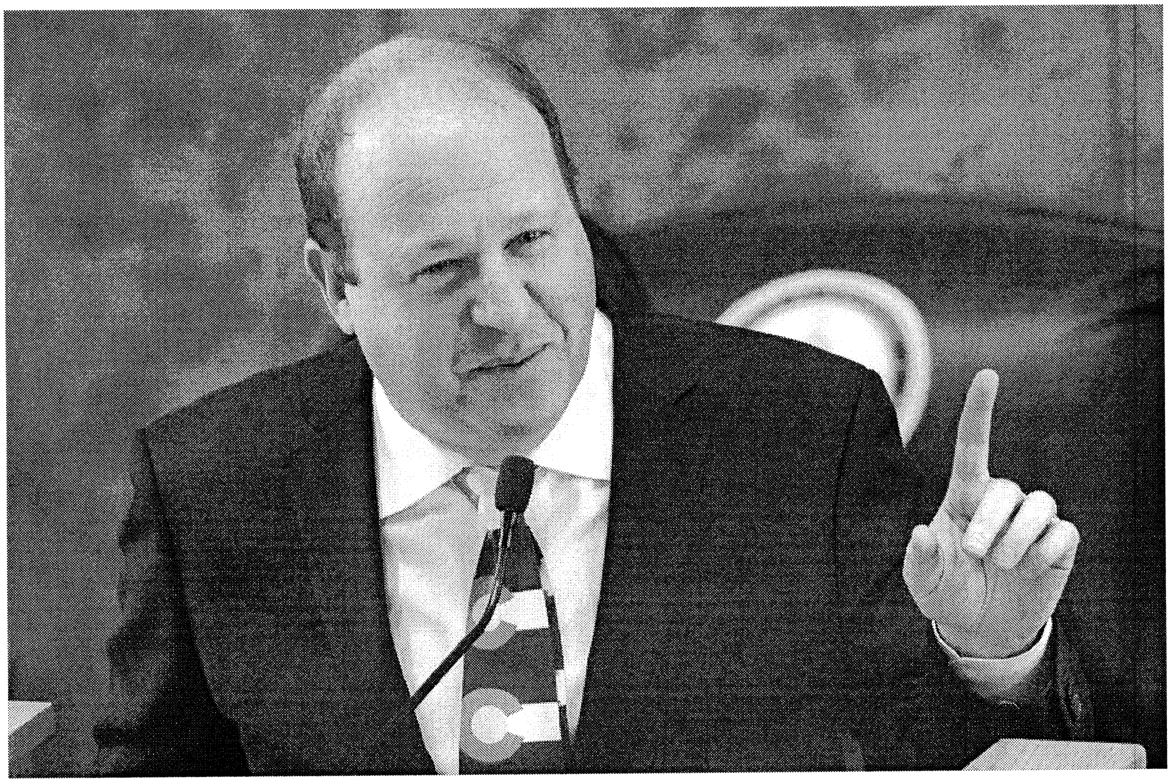
"Colorado is on track to nearly zero out power emissions -report" [Energy Wire 11/2/23]

ENERGYWIRE

Colo. on track to nearly zero out power emissions — report

A new analysis examines how the state could slash climate-warming emissions from electricity.

BY: **JASON PLAUTZ** | 11/02/2023 06:46 AM EDT



Colorado Gov. Jared Polis (D) speaks to lawmakers earlier this year in Denver. | David Zalubowski, File/AP

ENERGYWIRE | Colorado can cut greenhouse gas emissions from its power sector by 98.5 percent by 2040 without adding costs for consumers or enacting major policy changes, according to a new analysis commissioned by the state.

The draft findings — which project that the state can meet its energy needs primarily through wind, solar and energy storage — offer a potential model to other states as they balance grid needs against phasing out fossil fuels, said Will Toor, the head of the state's energy office.

The nearly 100 percent drop in climate-wa ming en ssions for Colorado electricity is based on a comparison with 2005 levels.

"To me, the big takeaway is that the lowes cost eco omic deployment of resources gets us so much further than we expected," To said in a interview. "That's going to be the case in many other places as well."

Under Gov. Jared Polis (D), Colorado has set a goal of reducing power-sector greenhouse gas emissions by 80 percent of 2005 levels by 2030 and to achieve economywide net-zero emissions by 2050. The new study conducted by Ascend Analytics was designed to model scenarios for achieving zero or near-zero emissions from the power sector by 2040 and identifying any new policies to help achieve that goal.

The study, however, found that the lowest-cost option would get the state nearly there, relying solely on existing technologies. That scenario sees the state meet more than 98 percent of its needs in 2040 through a combination of wind, solar and batteries, as well as energy efficiency upgrades.

It also keeps 8,215 megawatts of gas plants online. However, those plants would be kept in reserve as backup power and would account for an estimated 1 percent of the state's electricity. Gas provided about 26 percent of the state's electricity in 2022, according to the U.S. Energy Information Administration.

In all, that scenario would slash the state's electricity-related greenhouse gas emissions to 565,000 metric tons in 2040, down from more than 40 million in 2005. All told, the plan would cost about $37.5 billion through 2040 based on current costs, which is in line with what Colorado ratepayers would be expected to pay already for capital, operating and maintenance cost.

Toor said that the findings show the potential of a rapid energy transition. That's in a state that got more than 60 percent of its power from coal a decade ago.

"Our utilities are able to move forward with big plans that are good for customers and putting us on the pathway to very low — almost no — pollution," Toor said. "They can think ambitiously about the next decade, while still maintaining a reliable electric system and minimizing costs to consumers."

The full findings will be publicly released before the end of the year.

Gwen Farnsworth, deputy director of state advocacy at Western Resource Advocates, said in an email that the analysis informs a "'no regrets' pathway" to meet the state's goals.

"By guiding near term utility investment decisions based on a 98.5% emissions reduction glidepath by 2040, we're not requiring utilities to make all their 2040 investment decisions now," Farnsworth said. "We need to see what new clean energy technical developments emerge over the next few years, particularly for long-duration storage and potentially clean dispatchable options that we don't have commercially available today."

Xcel Energy spokesperson Michelle Aguayo said in a statement that the company — which has the largest electric utility operations in Colorado — is analyzing the study and is "encouraged" by the findings.

"We agree there is a need for new 24/7 carbon-free technology to achieve deep carbon reductions," Aguayo said. "The state's policies will enable us to reduce carbon emissions greater than 80% by 2030 and will inform our future investments into the local infrastructure necessary to move clean energy reliably into our customers' homes — while keeping bills low."

Xcel has had regulatory plans approved that would cut its carbon emissions in Colorado by 80 percent from 2005 levels by the end of the decade, while closing its final coal plant by the end of 2031.

In September, the utility filed an updated clean energy plan for Colorado that proposes doubling the amount of renewable energy on its system through 2030 to transition more than 80 percent of the power supply to renewables. That plan — which will have to be approved by the state — is projected to increase average electricity rates 2.3 percent per year, according to Xcel.

Still, according to the new state study, achieving the final 1.5 percent emissions cut could be costly. One scenario in the analysis put the cost of a 100 percent emissions cut at $9 billion above the current scenario, a roughly 25 percent increase. That scenario would replace gas with new sources like geothermal energy and hydrogen power.

Despite the fact that those emerging technologies — as well as carbon capture on gas plants — would not be needed under the low-cost scenario, Toor said the state is still interested in exploring their potential. Polis led a study of the potential for geothermal energy in the West through the Western Governors' Association, and the state teamed with two neighbors to apply for federal hydrogen funding, although that application was not successful.

Toor said that Colorado remains "excited" about supporting early deployments of those technologies, pointing to the rapid drop in price of wind and solar over the previous two decades.

"Those were not the cheapest sources of electricity, but it was important to begin deploying them and learn by doing," Toor said. "That early deployment was important to getting to where we are today. So supporting near-term deployment of geothermal and hydrogen is good policy if we want to maximize our opportunities."

Appendix S

Citizen's Utility Board Analysis of CEJA

CUB

1-800-669-5556

WHAT IS THE CLIMATE & EQUITABLE JOBS ACT?

An in-depth look at the latest energy legislation

The Climate & Equitable Jobs Act (CEJA) is historic legislation the Illinois General Assembly passed in 2021. If implemented correctly, this 900-page law could be a national model on how states can fight the most devastating and expensive consequences of climate change while controlling costs for energy customers.

WHAT DOES THE CLIMATE & EQUITABLE JOBS ACT DO?

The Climate & Equitable Jobs Act…

- Moves Illinois to 100 percent carbon-free power by 2045.
- Expands energy efficiency and other cost-saving opportunities for consumers.
- Implements the toughest utility ethics standards in state history.
- Launches a major expansion of cleaner, more affordable modes of transportation.
- Implements equity programs that help bring benefits of the clean energy economy to all communities.

WHAT ARE THE MAIN COMPONENTS OF CEJA?

Cost-Saving Measures:

- Sets the stage for lower "capacity" charges, hidden fees on our electric bills that pay big generators for reserve power. ComEd customers pay too much for capacity: about $1.7 billion a year—much of that to support fossil fuels. But federal regulators are reforming the system to support cleaner energy, so CEJA's historic expansion of low-cost clean energy opens the door to lower capacity costs.
- Extends electric energy efficiency programs beyond a 2030 end-date mandated by past legislation. Those programs have already saved consumers billions.
- Requires utilities to pass through the savings from recent federal corporate tax cuts over the next few years, rather than the decades the utilities favored.
- Creates a process for state regulators to consider a new low-income rate and prohibits late fees and customer deposits for lower-income customers.

Utility Accountability Reforms:

- Replaces the unfair formula-rate system with a rate-setting system that provides more oversight by the Illinois Commerce Commission (ICC).
- Launches a long-range, inclusive and transparent planning process to cost-effectively clean up the power-grid. The ICC will develop performance and tracking metrics and incentives to get electric utilities to prioritize pro-consumer benefits like cost-effective investment and affordability.
- Creates an independent ethics monitor, hired by the ICC, to help watchdog utilities. Major utilities must have a compliance officer at their headquarters to ensure the companies are following ethics guidelines—including restrictions on utility lobbying—and cooperating with the independent monitor.
- Requires public officials to disclose if immediate family members work for utilities.
- Prohibits ComEd from forcing customers to pay for any criminal penalties associated with its corruption scandal that was uncovered in 2020.

Promoting cleaner, more affordable transportation:

- Increases support for electric transportation, aiming to put 1 million battery-powered cars and trucks on the road by 2030.
- Includes incentives for electrifying public transit, school buses and city-owned vehicles.
- Creates rebates of up to $4,000 for customers who buy electric vehicles. Promotes creative programs such as EV car-sharing and lower-income EV rebates.

- Requires utilities to launch ICC-approved programs to help ensure that the electrification of transportation is done in a way that benefits all consumers, not just those who own EVs.

Promoting clean, affordable energy:

- Achieves a carbon-free power grid by 2045, closing all fossil-fuel power plants.
- Increases support for renewable energy to reach 40 percent by 2030 and 50 percent by 2040.
- Immediately opens the closed solar incentive programs to save solar jobs, and creates thousands of new jobs in renewable energy.
- Increases funding for the Illinois Solar for All program—which gives lower-income customers access to solar power—from $30 million a year to $70 million a year.

Making sure all Illinois benefits from clean energy:

- Establishes a $40 million grant program to support communities impacted by power plant closings, including towns where the fossil fuel industry has abandoned the community.
- Protects more than 2,000 jobs in nuclear power plants by giving a subsidy to Exelon. (CUB note: Keeping carbon-free nuclear power plants open is the fastest, cheapest way for Illinois to fight climate change. The company pushed for a much bigger subsidy but got billions of dollars less.)
- Targets $80 million per year for clean energy workforce and contractor development programs in Black and Brown communities. CEJA creates a "Green Bank" to finance clean energy projects.

HOW MUCH WILL CEJA COST?

CUB estimates the legislation will cost customers an average of between $3 and $4 per month over the next five years. That cost estimate does not include savings made possible by this legislation (for example, savings from energy efficiency, low-cost solar energy or lower capacity and energy prices). With proper implementation, CEJA should lead to consumer savings over time.

WHY DOES CUB SUPPORT CEJA?

While CUB doesn't agree with every provision in this compromise legislation, the overall act is a good deal for Illinois consumers. It is the most cost-effective way for the state to fight climate change. The worst, most expensive outcome for Illinois consumers would have been if the state failed to pass a bill. A climate change report by the United Nations in 2021 was described as a "code-red for humanity," meaning volatile weather will only get worse and more costly for consumers in Illinois, the country and the world in years to come. For example, CUB's research team found that hotter weather could cause ComEd electric bills to increase by nearly $11 billion in the next few decades just because of higher air conditioning costs. CUB supported CEJA because fighting climate change is necessary to reduce consumers' future costs.

FOR MORE INFORMATION:

Keep track of CEJA's implementation by visiting **CitizensUtilityBoard.org**.

Appendix T

Spectrum News 10/13/21 (HB 9510;

"North Carolina has a clean energy law. Here’s what’s in it"

Flanked by Republican and Democratic leaders fromt he General Assembly, North Carolina Gov. Roy Cooper signed the clean energy bill into law Wednesd Duncan)

POLITICS

North Carolina has a new clean energy law. Here’s what’s in it

BY CHARLES DUNCAN RALEIGH
PUBLISHED 4:20 PM ET OCT. 13, 2021

By the end of this decade, North Carolina will cut carbon emissions by 70% — at least that's the mandate in the new clean energy bill signed into law by the governor Wednesday.

House Bill 951, titled Energy Solutions for North Carolina, gives the state Utilities Commission the ability to shutter dirty coal-fired power plants and to work with energy companies and others to get power producers to carbon neutrality by 2050, based on 2005 levels.

What You Need To Know

- Gov. Roy Cooper signed a new clean energy bill into law Wednesday, which passed with strong bipartisan support

- The law requires the Utilities Commission to cut emissions by 70% by 2030 and get to carbon neutrality by 2050, based on 2005 levels
- Coal-fired power plants will be replaced by solar and other renewable energy sources
- Consumers could see electricity rates increase under the new law

"Today, North Carolina moves strongly into a reliable and affordable clean energy future. This new bipartisan law requires the North Carolina Utilities Commission to take steps needed to get North Carolina a 70% reduction in carbon emission by the year 2030 and to carbon neutrality by 2050," the governor said at a signing ceremony Wednesday.

"For the first time ever, the Utilities Commission has the authority and the duty to cut carbon emissions," Cooper said.

The bill had been stalled out for months in the General Assembly, but a bipartisan deal on clean energy sent it sailing through committee and to the governor's desk in a matter of weeks.

Republican and Democratic leaders from both the North Carolina Senate and House joined Cooper for the ceremony on the south lawn of the Governor's Mansion at noon Wednesday.

The bill had been through 49 different versions since it was first introduced. But leaders from the General Assembly all celebrated how they could negotiate a bill that passed with strong bipartisan support.

"It's great to see a bipartisan, bicameral bill that can pass like this," Republican House Speaker Tim Moore said.

Dan Blue, leader of the Senate Democrats, said, "Democrats and Republicans understand we have to curb the effects of climate change."

What the law does

The new law will retire some coal-fired power plans. The Utilities Commission will decide which Duke Energy power plants need to be shuttered.

The state will replace the power from those plants with new renewable energy sources. The law requires the commission to pick the lowest-cost options to keep people's power bills as low as possible.

Large-scale solar and other renewable energy sources will become key sources of power for North Carolina’s electric grid.

For solar, the law says utility companies will be required to buy 45% of their solar power from smaller solar producers. Utilities, like Duke Energy, could generate 55% of the solar power on their own.

Electric rates could go up for consumers under the new bill, according to the Associated Press.

The bill gives Duke Energy the ability to ask for rate increases in three-year blocks instead of having to ask for rate increases every year.

The Utilities Commission estimated that Duke Energy customers could see rates go up by 4.5% by the end of this decade under the House bill, according to the AP. An industrial customers group said the price increase could be several times what was estimated for the House bill, the AP reports.

Appendix U
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Strong economic development tool

North Carolina was one of the first states in the Southeast to implement mandatory reliability standards, Kendal Bowman, North Carolina state president with Duke Energy, said in an interview with S&P Global. In 2021, bipartisan legislation was passed for carbon neutrality by 2050.

"I really think the policymakers here in the state recognize that providing companies with a clear path for clean energy, ultimately with that net-zero goal would be a strong economic development tool for our state," Bowman said. "We're really seeing a lot of companies wanting to come to North Carolina. And I think it's because North Carolina does have this clear path to clean energy and that net-zero goal."

North Carolina is the No. 1 state to do business in the country for two years in a row, Bowman said, adding there's been tremendous economic development in the past year.

State policy changes

The latest state to strive for 100% clean power is Michigan after lawmakers finalized legislation Nov. 8 to establish a 100% carbon-free energy standard by 2040 for the state. The plan stems from an executive order that Governor Gretchen Whitmire, who is expected to sign the measure into law, issued in 2020 to achieve economy-wide carbon neutrality no later than 2050.

US State Clean Energy Goals, Political Affiliations and Renewables Rankings[1]

Demoratic Split Republican

State	Ultimate Clean Energy Goals, Standards	Political Trifecta	Q3 2023 Renewables Rank
California	100% carbon-free power by 2045	D	2
Colorado	100% clean energy by 2050	D	8
Minnesota	100% carbon-free power by 2040	D	10
New York	100% carbon-free power by 2040	D	11
Oregon	50% renewables by 2040; 100% GHG emissions cut from 1990 levels by 2040	D	12
Michigan	100% carbon-free power by 2040; Economy-wide carbon neutral by 2050	D	17
Washington	100% carbon-free power by 2030	D	20
Maine	100% clean energy by 2050	D	29
Massachusetts	Net-Zero GHG emissions by 2050	D	32
Illinois	100% clean energy by 2050	D	34
New Mexico	100% carbon-free power by 2045	D	35
Maryland	100% clean electricity by 2040	D	37
Hawaii	100% renewable energy by 2045	D	38
Connecticut	100% carbon-free power by 2040	D	41
Rhode Island	100% fossil fuel-free power by 2033	D	42
New Jersey	100% clean energy by 2035	D	46
Delaware	40% clean energy by 2035; 90% GHG emissions cut from 2005 levels by 2050	D	49
Kansas	20% renewables by 2020 (voluntary)	No	6
North Carolina	Carbon-neutral power by 2050	No	15
Nevada	100% carbon-free power by 2050	No	16
Vermont	90% renewables by 2050; 80% GHG emissions cut from 1990 levels by 2050	No	24
Pennsylvania	18% renewables by 2021; 80% GHG emissions cut from 2005 level by 2050	No	28
Wisconsin	100% carbon-free power by 2050	No	36
Alaska	50% renewables by 2025	No	39
Arizona	15% renewables by 2025	No	43
Virginia	100% carbon-free power by 2045 (Dominion); 2050 (Appalachian Power)	No	45
Kentucky	No Goal	No	50
Texas	10,000 MW of renewables by 2025, which ends Sept. 1, 2025	R	1
Idaho	No Goal	R	3
Oklahoma	15% renewables by 2015	R	4
Indiana	10% renewables by 2025 (voluntary)	R	5
Florida[2]	No Goal	R	7
Nebraska	No state goals, but utilities have goals of net-zero emissions by 2050	R	9
Iowa	No Goal	R	13
Arkansas	No Goal	R	14
North Dakota	10% renewables by 2015 (Governor requests carbon neutrality by 2030)	R	18
Georgia	No Goal	R	19
New Hampshire	25.2% renewables by 2021	R	21
South Dakota	10% renewables by 2015 (voluntary)	R	22
Wyoming	20% low-carbon power by 2030	R	23
Mississippi	No Goal	R	25
Utah	20% renewables by 2025	R	26
Ohio	8.5% renewables by 2026	R	27
Montana	15% renewables by 2015	R	30
West Virginia	No Goal	R	31
South Carolina	2% renewables by 2021 (voluntary)	R	33
Tennessee	No Goal	R	40
Missouri	15% renewables for IOUs by 2021	R	44
Alabama	No Goal	R	47
Louisiana[3]	Net-zero GHG emissions by 2050 (aspirational executive order)	R	48

1) Combined capacity of wind, utility-scale solar and battery storage. 2) Florida's Department of Agriculture set a goal for the state of 100% renewable energy for utilities by 2050, but the goal was not endorsed by the state's government. 3) In 2020, Louisiana's governor set a climate action plan with a net-zero goal by 2050.
Includes the results of fall 2023 elections.
A government trifecta is a political situation in which the same political party controls the executive branch and both chambers of the legislative branch.

Source: ACP, S&P Global Platts, EIA, National Conference of State Legislatures, individual state agencies, S&P Global Market Intelligence, US Energy Information Administration