UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** For the fiscal year ended December 31, 2024

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** For the transition period from to .

Commission file number 001-42486

VENTURE GLOBAL, INC.

(Exact Name of Registrant as Specified in Its Charter)

DELAWARE	**95-3539083**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification Number)

1001 19TH STREET NORTH, SUITE 1500
ARLINGTON, VIRGINIA 22209
(Address of Principal Executive Offices)

(202) 759-6740
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Trading Symbol	Name of Each Exchange on Which Registered
Class A common stock, $ 0.01 par value	VG	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☐ No ☒
Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files such files). Yes ☒ No ☐
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐ Accelerated filer ☐	Smaller reporting company ☐
Non-accelerated filer ☒ (Do not check if a smaller reporting company)	Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐
Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☐
If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐
Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒
The registrant was not a public company as of the last business day of its most recently completed second fiscal quarter and, therefore, it cannot calculate the aggregate market value of its voting and non-voting common equity held by non-affiliates as of such date.
As of February 14, 2025, the number of shares of the registrant's Class A common stock outstanding was 450,937,393, and the number of shares of the registrant's Class B common stock outstanding was 1,968,604,458.

DOCUMENTS INCORPORATED BY REFERENCE

Certain portions of the definitive proxy statement for the registrant's Annual Meeting of Stockholders (to be filed within 120 days of the close of the registrant's fiscal year) are incorporated by reference into Part III of this Annual Report on Form 10-K. Except with respect to information specifically incorporated by reference in this Annual Report on Form 10-K, such proxy statement will not be deemed to be filed as part hereof.

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GLOSSARY OF KEY TERMS

Unless otherwise indicated or the context otherwise requires, as used in this Form 10-K:

- *Bcf* means billion cubic feet;
- *Bcf/d* means billion cubic feet per day;
- *Bcf/yr* means billion cubic feet per year;
- *bolt-on expansion liquefaction capacity* means the incremental capacity that can be generated by our projects as a consequence of potential expansions to our existing or planned projects;
- *Calcasieu Funding* means Calcasieu Pass Funding, LLC;
- *Calcasieu Holdings* means Calcasieu Pass Holdings, LLC;
- *Class A common stock* means our Class A common stock, par value $0.01 per share, entitled to one vote per share;
- *COD* means the commercial operations date, which is the first day of commercial operations at a project or a phase of a project, as applicable, as specifically defined in the relevant post-COD SPAs, and which does not occur unless and until: (i) all of the facilities comprising the relevant project, or phase thereof, have been completed and commissioned, including any ramp up period, (ii) the project or phase thereof is capable of delivering LNG in sufficient quantities and necessary quality to perform all of its obligations under such post-COD SPAs, and (iii) the applicable project company has notified the customer under the post-COD SPAs;
- *commercial operations* means the production period commencing after the occurrence of COD at a project or a phase of a project, as applicable;
- *commissioning* or *commissioning phase* means, with respect to our LNG projects, the phase of development where our facilities undergo certain required performance and reliability testing, which includes (i) the sequential start-up and testing of certain key equipment (e.g., liquefaction trains) as it is installed during construction and (ii) the testing and tuning of the full integrated LNG project after all key equipment and modules have passed their individual performance tests;
- *commissioning cargos* means the LNG cargos produced by us during the commissioning phase of an LNG project, which commences once a project produces its first quantities of LNG and ends once a project, or phase thereof, achieves COD. Proceeds from the sale of commissioning cargos are recognized in our financial statements as a reduction to the cost basis of construction in progress until assets are placed in service from an accounting perspective, the timing of which may differ from COD. After assets are placed in service from an accounting perspective, the proceeds are recognized through revenue;
- *Company* means Venture Global, Inc., but not its subsidiaries;
- *CP Express* means Venture Global CP Express, LLC;
- *CP2* means Venture Global CP2 LNG, LLC;
- *CP3* means Venture Global CP3 LNG, LLC;
- *CP3 Express* means Venture Global CP3 Express, LLC;
- *Delta* means Venture Global Delta LNG, LLC;
- *Delta Express* means Venture Global Delta Express, LLC;
- *DOE* means the United States Department of Energy;
- *DPU* means delivered at place unloaded, which, with respect to LNG SPAs, requires the seller to deliver and unload LNG at one or more designated destinations;
- *EIS* means Environmental Impact Statement;
- *EPC* means engineering, procurement and construction;
- *EPCM* means engineering, procurement, and construction management, which entails certain supervision, management, and co-ordination of EPC and other construction interface work;
- *excess capacity* or *excess LNG* means the amount of LNG that is produced by our liquefaction facilities that is in excess of the nameplate capacity;
- *FERC* means the Federal Energy Regulatory Commission;
- *FID* means the final investment decision with respect to the development of a project or a phase thereof, which, with respect to an LNG project, requires that the project has secured (i) all of the debt and equity financing arrangements necessary to fully construct, commission, and operate such project or phase thereof and (ii) all of the necessary permits to construct, operate, and export LNG;
- *FOB* means free on board which, with respect to LNG SPAs, requires the seller to deliver and load LNG onto the buyer's LNG tankers at the seller's export terminal;
- *FTA* means a free trade agreement;
- *Gator Express* means Venture Global Gator Express, LLC;

- *Henry Hub* means the final settlement price (in $ per MMBtu) for the New York Mercantile Exchange's Henry Hub natural gas futures contract for the month in which a relevant cargo's delivery window is scheduled to begin;
- *IPO* means our initial public offering of Class A common stock, par value $0.01 per share, that we completed on January 27, 2025;
- *Legacy VG Partners* means Venture Global Partners, LLC;
- *liquefaction train* or *train* means a liquefaction production unit that cools natural gas to a liquid state;
- *LNG* means liquefied natural gas, or methane, supercooled to -260°F and converted into a liquid state, which reduces it to 1/600th of its original volume, enabling large quantities of natural gas to be loaded and shipped by LNG tankers;
- *LNG Commissioning Sales Agreements* means short-term sales agreements under which commissioning cargos are sold at prevailing market prices when executed;
- *MMBtu* means million British thermal units;
- *mtpa* means million tonnes per annum, which is a common unit of measurement for annual LNG production;
- *MW* means one million watts, a unit of power;
- *nameplate capacity* means, unless the context otherwise requires, the conservative measure of LNG production capability, based on vendor guaranteed LNG output of each of our facilities;
- *natural gas* means any hydrocarbons that are gaseous at standard temperature and pressure;
- *NYSE* means the New York Stock Exchange;
- *peak production capacity* means the total combined amount of LNG that our liquefaction facilities are anticipated to produce, which is the sum of such facility's expected nameplate capacity and excess capacity (or excess LNG);
- *post-COD SPA* means an SPA for the sale and purchase of LNG after COD has occurred for a particular project or phase thereof;
- *Pre-IPO Stockholders* means VG Partners and each other holder of shares of our common stock outstanding immediately prior to consummation of our IPO;
- *regasification* means the process of heating LNG to convert it from a liquid to gaseous state after the LNG is offloaded from an LNG carrier;
- *SPA* or *LNG SPA* means LNG sales and purchase agreement;
- *stick-built* means a traditional labor-intensive construction method where raw materials, parts and components are delivered to site for on-site fabrication, assembly and construction by very large workforces;
- *Stock Split* means the approximately 4,520.3317-for-one forward stock split of our Class A common stock, which we effected in connection with our IPO;
- *TBtu* means trillion British thermal units;
- *TCP* means TransCameron Pipeline, LLC;
- *total contracted revenue* means, as of a particular date, the sum, for the remainder of the term for all of our post-COD SPAs then in effect, of (i) the volume weighted average of the fixed facility charge component for all such post-COD SPAs for each project or project phase, multiplied by the contracted volumes for all such post-COD SPAs for the applicable project or project phase, in each case adjusted for inflation (assuming that 17.5% of the fixed facility charge component increases by 2.5% annual inflation every year following the first full year after COD), and (ii) the lifting revenue that would be earned for all such post-COD SPAs, assuming, for illustrative purposes only, all volumes contracted under each such post-COD SPA are lifted at an assumed Henry Hub gas price per MMBtu of $4.00 per MMBtu, in each case using a conversion factor of MMBtu to mtpa of 52. See Item 1A.—*Risk Factors*—*Risks Relating to Our Business—Total contracted revenue is based on certain assumptions and is presented for illustrative purposes only and actual sales under our SPAs may differ materially from such illustrative operating results*;
- *Trigger Date* means the first time at which either (i) VG Partners and its permitted transferees, collectively, no longer beneficially own more than 50% of the combined voting power of our outstanding common stock entitled to vote generally in the election of directors, or (ii) we fail to qualify as a "controlled company" (or similar) under the applicable stock exchange rules;
- *TRIR* means total recordable incident rate;
- *Venture Global*, *we*, *our*, *us* or similar terms mean Venture Global, Inc. and its subsidiaries, collectively;
- *VG Commodities* means Venture Global Commodities, LLC;
- *VG Partners* means Venture Global Partners II, LLC, our controlling shareholder;
- *VGCP* means Venture Global Calcasieu Pass, LLC;
- *VGLNG* or *Venture Global LNG* means Venture Global LNG, Inc.; and
- *VGPL* means Venture Global Plaquemines LNG, LLC.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Form 10-K contains forward-looking statements. We intend such forward-looking statements to be covered by the safe harbor provisions for forward-looking statements contained in Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. All statements, other than statements of historical facts, included herein are "forward-looking statements." In some cases, forward-looking statements can be identified by terminology such as "may," "might," "will," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "predict," "potential," "pursue," "target," "continue," the negative of such terms or other comparable terminology.

These forward-looking statements, which are subject to risks, uncertainties and assumptions about us, may include projections of our future financial performance, expectations regarding the development, construction, commissioning and completion of our projects, estimates of the cost of our projects and schedule to construct and commission our projects, our anticipated growth strategies and anticipated trends impacting our business. These statements are only predictions based on our current expectations and projections about future events. There are important factors that could cause our actual results, level of activity, performance or achievements to differ materially from the results, level of activity, performance or achievements expressed or implied by the forward-looking statements. Those factors include the following:

- our potential inability to maintain profitability, maintain positive operating cash flow and ensure adequate liquidity in the future, including as a result of the significant uncertainty in our ability to generate proceeds and the amount of proceeds that will regularly be received from sales of commissioning cargos and excess cargos due to volatility and variability in the LNG markets;
- our need for significant additional capital to construct and complete some future projects, and our potential inability to secure such financing on acceptable terms, or at all;
- our potential inability to construct or operate all of our proposed LNG facilities or pipelines or any additional LNG facilities or pipelines beyond those currently planned, including any of the bolt-on expansion opportunities which we have identified, and to produce LNG in excess of our nameplate capacity, which could limit our growth prospects, including as a result of delays in obtaining regulatory approvals or inability to obtain requisite regulatory approvals;
- significant operational risks related to our natural gas liquefaction and export projects, including the Calcasieu Project, the Plaquemines Project, the CP2 Project, the CP3 Project, the Delta Project, any potential bolt-on expansions, any future projects we develop, our pipelines, our LNG tankers, and our regasification terminal usage rights;
- our potential inability to accurately estimate costs for our projects, and the risk that the construction and operations of natural gas pipelines and pipeline connections for our projects suffer cost overruns and delays related to obtaining regulatory approvals, development risks, labor costs, unavailability of skilled workers, operational hazards and other risks;
- potential delays in the construction of our projects beyond the estimated development periods;
- our potential inability to enter into the necessary contracts to construct the CP2 Project, the CP3 Project, the Delta Project, or any potential bolt-on expansion on a timely basis or on terms that are acceptable to us;
- our potential inability to enter into post-COD SPAs with customers for, or to otherwise sell, an adequate portion of the total expected nameplate capacity at the CP2 Project, the CP3 Project, the Delta Project, any potential bolt-on expansions, or any future projects we develop;
- our dependence on our EPC and other contractors for the successful completion of our projects and delivery of our LNG tankers, including the potential inability of our contractors to perform their obligations under their contracts;
- various economic and political factors, including opposition by environmental or other public interest groups, or the lack of local government and community support required for our projects, which could negatively affect the timing or overall development, construction and operation of our projects;
- the effects of FERC regulation on our interstate natural gas pipelines and their FERC gas tariffs;

- our potential inability to obtain, maintain or comply with necessary permits or approvals from governmental and regulatory agencies on which the construction of our projects depends, including as a result of opposition by environmental and other public interest groups;
- the risk that the natural gas liquefaction system and mid-scale design we utilize at our projects will not achieve the level of performance or other benefits that we anticipate;
- potential additional risks arising from the duration of and the phased commissioning start-up of our projects;
- the potential risk that our customers or we may terminate our SPAs if certain conditions are not met or for other reasons;
- potential decreases in the price of natural gas and its related impact on our ability to pay the cost of gas transportation, the payment of a premium by us for feed gas relative to the contractual price we charge our customers, or other impacts to the price of natural gas resulting from inflationary pressures;
- the potential negative impacts of seasonal fluctuations on our business;
- our current and potential involvement in disputes and legal proceedings, including the arbitrations and other proceedings currently pending against us and the possibility of a negative outcome in any such dispute or proceeding and the potential impact thereof on our results of operations, liquidity and our existing contracts;
- the risks related to the development and/or contracting for additional gas transportation capacity to support the operation and expansion capacity of our LNG projects;
- the risks related to the management and operation of our LNG tanker fleet and our future regasification terminal usage rights;
- the uncertainty regarding the future of international trade agreements and the United States' position on international trade, including the effects of tariffs;
- the potential effects of existing and future environmental and similar laws and governmental regulations on compliance costs, operating and/or construction costs and restrictions;
- our indebtedness levels, and the fact that we may be able to incur substantially more indebtedness, which may increase the risks created by our substantial indebtedness; and
- risks related to other factors discussed under Item 1A.—*Risk Factors* of this Form 10-K.

In addition, new risks emerge from time to time as we operate in a very competitive and rapidly changing business environment. It is not possible for our management to predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements we may make. Given these uncertainties, you should not place undue reliance on these forward-looking statements.

All such factors are difficult to predict, contain uncertainties that may materially affect actual results and may be beyond our control. New factors emerge from time to time, and it is not possible for management to predict all such factors or to assess the impact of each such factor on us.

Any forward-looking statement speaks only as of the date on which such statement is made, and we do not undertake any obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made except as required by the federal securities laws. If one or more of these or other risks or uncertainties materialize, or if our underlying assumptions prove to be incorrect, our actual results may vary materially from what we may have expressed or implied by these forward-looking statements. We caution that you should not place undue reliance on any of our forward-looking statements. Furthermore, new risks and uncertainties arise from time to time, and it is impossible for us to predict those events or how they may affect us.

SUMMARY OF MATERIAL RISKS ASSOCIATED WITH OUR BUSINESS

Our business is subject to numerous risks and uncertainties that you should be aware of in evaluating our business. These risks include, but are not limited to, the following:

- Our ability to maintain profitability and positive operating cash flows is subject to significant uncertainty.
- We have only a limited track record and historical financial information, and there is no assurance that our business will be successful over the long term.
- Historical proceeds from commissioning cargo sales at the Calcasieu Project, which has had an extended commissioning period due to unanticipated challenges with equipment reliability that we are in the process of remediating and which began producing LNG in a high-price environment, may not be indicative of the duration of the commissioning period or the amount of proceeds for any future period or for any of our other projects, including bolt-on expansions thereof.
- Our ability to generate proceeds from sales of commissioning cargos is subject to significant uncertainty and volatility in such proceeds, given significant volatility in spot-market prices.
- We have not entered into SPAs with customers for the total expected nameplate capacity at the CP2 Project, the CP3 Project, the Delta Project, or any potential bolt-on expansions, and our failure to enter into final and binding contracts for an adequate portion of, or to otherwise sell, the expected nameplate capacity of any of our projects, including any phases or expansions thereof, could impact our ability to take FID for such projects.
- Our revenues and operating margins may be adversely affected if we are unable to produce and sell liquefaction capacity in excess of the nameplate capacity of our facilities.
- Our customers or we may terminate our SPAs if certain conditions are not met or for other reasons.
- Our ability to generate cash under our post-COD SPAs is substantially dependent upon the performance by a limited number of our customers, and we could be materially and adversely affected if certain of these customers fail to perform their contractual obligations for any reason.
- Our operating margins may be adversely affected if the price of natural gas decreases, if we pay a premium for feed gas relative to the contractual spot price we charge our customers, or as a result of inflationary pressures.
- We may not be able to purchase or receive physical delivery of sufficient natural gas to satisfy our delivery obligations under the SPAs, which could have a material adverse effect on us.
- Our limited diversification could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.
- We are dependent on the strategic direction of Michael Sabel, our Chief Executive Officer, Executive Co-Chairman of the Board and Founder, and Robert Pender, our Executive Co-Chairman, Executive Co-Chairman of the Board and Founder.
- We and our contractors, including our EPC contractors, may experience increased labor costs, and the unavailability of skilled workers or our failure to attract and retain qualified personnel could adversely affect us.
- We will require significant additional capital to construct and complete certain of our projects, and we may not be able to secure such financing on time with acceptable terms, or at all, which could cause delays in our construction, lead to inadequate liquidity and increase overall costs.
- We may not construct or operate all of our proposed LNG facilities or pipelines or any additional LNG facilities or pipelines beyond those currently planned, and we may not pursue some or any of the bolt-on expansion opportunities we have identified at our current projects, which could limit our growth prospects.
- We are dependent on our contractors for the successful completion of our projects and any bolt-on expansion opportunities at our projects that we may pursue, and any failure by our contractors to perform their contractual obligations could have a material adverse impact on our projects.

- We have not entered into all of the definitive agreements for the CP2 Project, the CP3 Project or the Delta Project, and there can be no assurance that we will be able to do so on a timely basis or on terms that are acceptable to us.
- Certain of our contractual arrangements relating to development and construction of our projects include termination rights that, if exercised, could have a material adverse impact on our projects.
- Our estimated costs for our projects have been, and continue to be, subject to change due to various factors.
- Delays in the construction of our projects beyond the estimated development periods could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.
- Our business could be materially and adversely affected if we do not secure the right or if we lose the right to situate certain lateral pipelines, longer-haul pipelines or any other pipeline infrastructure for any of our projects on property owned by third parties, or if we do not complete the construction of those pipelines in a timely fashion.
- The natural gas liquefaction system and mid-scale design we utilize at our projects are the first of such sized modules developed by us and Baker Hughes, and there can be no assurance that these modules, or our projects, will achieve the level of performance or other benefits that we anticipate over the long term.
- Competition in the LNG industry is intense, and certain of our competitors may have greater financial, engineering, marketing and other resources than we have.
- We face competition based upon the international market price for LNG.
- Servicing our indebtedness and preferred equity will require a significant amount of cash and we may not have sufficient cash, operating cash flows and capital resources to service our existing and future indebtedness and preferred equity.
- We may fail to receive the required approvals and permits from governmental and regulatory agencies for our projects.
- If we are unsuccessful in any current or potential future arbitration proceedings with customers, the amounts that we are required to pay may be substantial or certain of our post-COD SPAs may be terminated, which may lead to an acceleration of all our debt for the relevant project.
- VG Partners has significant influence over us, including control over decisions that require their approval, which could limit your ability to influence the outcome of key transactions, including a change of control.
- There is the possibility of significant fluctuations in the price of our Class A common stock.
- We cannot guarantee that we will pay further dividends on our Class A common stock in the future and, consequently, your ability to achieve a return on your investment will depend on appreciation in the price of our Class A common stock.
- We face risks related to the uncertainty regarding the future of international trade agreements and the United States' position on international trade.

The summary risk factors described above should be read together with our risk factors as described in the section titled *Risk Factors* in Part I, Item 1A. and the other information set forth on this Form 10-K. The risks summarized above or described in full below are not the only risks that we face. Additional risks and uncertainties not precisely known to us, or that we currently deem to be immaterial, may also materially adversely affect our business, financial condition, results of operations and future growth prospects.

PART I

ITEM 1. BUSINESS

Overview

Our Company

Venture Global is a long-term, low-cost provider of U.S. LNG sourced from resource rich North American natural gas basins. Venture Global's business includes assets across the LNG supply chain, including LNG production, natural gas transport, shipping and regasification. We have fundamentally reshaped the development and construction of LNG production, establishing us as a rapidly growing company delivering critical LNG to the world. Our innovative and disruptive approach, which is both scalable and repeatable, allows us to bring LNG to a global market years faster and at a lower cost. We believe supplying this clean, affordable fuel promotes global energy security and is essential to meeting growing global demand.

Natural gas is one of the most important resources worldwide and is required to generate reliable electricity that underpins economic development and drives industry. Once natural gas is supercooled to -260°F, it converts to liquid form and reduces to 1/600th of its original volume, enabling large quantities of natural gas to be loaded and shipped by LNG tankers. The resulting LNG can be transported to international markets that lack domestic supply, displacing more carbon intensive sources of energy such as coal, diesel, and heavy fuel oil, and serving as an integral part of a cleaner energy future. We believe our business model has demonstrated that in a competitive commodity market, lower cost and overall faster delivery wins market share. Our approach capitalizes on both of these advantages, supporting significant additional growth opportunities.

Our Liquefaction and Export Projects

We are commissioning, constructing, and developing five natural gas liquefaction and export projects near the U.S. Gulf Coast in Louisiana, utilizing our unique "design one, build many" approach. Each project is designed or is being developed to include an LNG facility and associated pipeline systems that interconnect with several interstate and intrastate pipelines to enable the delivery of natural gas into the LNG facility.

Below is a geographic overview of our five current projects, which is followed by a detailed description of each project.

As illustrated by the chart below, our five current projects are being designed to deliver a total expected peak production capacity of 143.8 mtpa, which consists of an aggregate of 104.4 mtpa expected nameplate capacity and an aggregate of 39.4 mtpa of expected excess capacity. These amounts do not account for any potential bolt-on expansion liquefaction capacity. The expected nameplate capacity of our facilities measures the minimum operating performance thresholds guaranteed by the equipment providers, and the expected excess capacity represents the additional LNG that we aim to produce above such guaranteed amounts. Although COD has not yet occurred under the post-COD SPAs for any of our projects, we have been generating proceeds from the sale of commissioning cargos at the Calcasieu Project since the first quarter of 2022 and at the Plaquemines Project since January 2025, and expect to do so at each of our other projects during commissioning prior to achieving COD for the relevant project or phase of a project.

Project Name	Number of Trains	Expected Nameplate Capacity	Expected Excess Capacity	Expected Peak Production Capacity	Stage of Development
Calcasieu Project	18	10.0 mtpa	2.4 mtpa(1)	12.4 mtpa(1)	Commissioning
Plaquemines Project	36	20.0 mtpa	7.2 mtpa(1)	27.2 mtpa(1)	Construction and Commissioning
CP2 Project	36	20.0 mtpa(2)	8.0 mtpa(2)	28.0 mtpa(2)	Engineering, Procuring Materials, and Manufacturing Modules
CP3 Project	54	30.0 mtpa(2)	12.0 mtpa(2)	42.0 mtpa(2)	Development
Delta Project	44	24.4 mtpa(2)	9.8 mtpa(2)	34.2 mtpa(2)	Development

(1) Targets based on, among other things, anticipated timeframes for the receipt of certain regulatory approvals as described in *—Governmental Regulation* of this Form 10-K.

(2) Anticipated based on capacity, scale, location and infrastructure. Subject to regulatory review and approval, among other things, and may change based on design considerations, engagement with contractors, and other factors.

Venture Global seeks to own all or substantially all of the equity ownership in its current five LNG projects and any future projects. As of the date of this Form 10-K, we own 100% of the common equity interests in all of our natural gas liquefaction and export projects. Upon COD for the Calcasieu Project, we expect our ownership of the common equity interests in the Calcasieu Project to be reduced to approximately 77% (assuming that we service all future distributions on the Holdings Preferred Units until the commencement of COD in cash), after adjusting for the automatic conversion of the convertible preferred units in Calcasieu Holdings held by an outside equity investor. We believe that our significant ownership stake in our projects provides us with full managerial control, facilitating nimble decision-making and speed of execution.

Optimization and Bolt-on Expansion Opportunities

Our projects also offer potential optimization, increased capacity and expansion opportunities. In particular, our projects are sited and designed with the intention of allowing for bolt-on expansions, incorporating laydown area, redundancies across the facility infrastructure and our mid-scale factory-fabricated liquefaction trains. Subject to receiving the requisite regulatory approvals, we intend to pursue the development of these expansion opportunities beyond our current combined expected peak production capacity of 143.8 mtpa. Any incremental equipment would benefit from pre-existing plant facilities and related infrastructure (such as marine offloading facilities, LNG storage tanks and perimeter walls), although may require, among other things, incremental natural gas supply arrangements, pipelines, and pipeline transportation capacity, for the applicable project in order to support the additional capacity. We aim to place up to an aggregate of approximately 49.5 mtpa of additional bolt-on expansion liquefaction capacity of incremental modular mid-scale liquefaction trains at most of our current projects. In particular, on March 6, 2025, we submitted to FERC a request to initiate the pre-filing process for additional facilities for a Plaquemines Project bolt-on expansion consisting of approximately 18.6 mtpa of incremental peak production capacity.

Our Project Development and Construction Approach

Our project development and construction approach utilizes proven liquefaction system technology and equipment in a unique mid-scale, factory-fabricated configuration that we developed. Instead of two or three large, complex liquefaction trains, the Calcasieu Project and the Plaquemines Project utilize 18 and 36 mid-scale factory-fabricated liquefaction trains, respectively. We expect to use the same approach and technology at the CP2 Project, the CP3 Project and the Delta Project. Our modules are built and assembled off-site at manufacturing and fabrication facilities in Italy and then shipped to our project sites fully-assembled and packaged for installation, allowing onsite work to progress in parallel. We believe our innovative configuration, long-term equipment contracting strategy and hands-on project management approach significantly reduces construction and installation costs, as well as construction time and schedule risk, thereby allowing us to be more cost-competitive in the LNG market while also producing substantial amounts of commissioning cargos and related cash proceeds. For example, our initial two projects, the Calcasieu Project and the Plaquemines Project, in each case, began producing LNG approximately two and a half years after the relevant final investment decision, while significant construction work remained ongoing.

While traditional LNG projects often rely on bespoke designs and configurations, our approach, leveraging factory-fabricated equipment manufactured with our "design one, build many" method, allows us to apply the lessons we learn at each project to our subsequent projects, with the goal of continuously improving our execution, accelerating construction timelines, reducing costs, and expanding production. We believe we will continue to benefit from this virtuous cycle as we grow.

Gas Supply and Transportation

We have entered into a portfolio of natural gas supply agreements with domestic natural gas suppliers to furnish feed gas to the Calcasieu Project and the Plaquemines Project for liquefaction and power generation. We have also entered into multiple transport capacity agreements with interstate pipeline companies to provide natural gas transportation to the Calcasieu Project and the Plaquemines Project via short-run lateral pipelines. The CP2 Project has entered into agreements for substantial firm transportation capacity with third parties and CP Express.

LNG Sales – Commissioning

By design, conventional, stick-built projects generally only engage in several months of commissioning production, thereby limiting the number of cargos produced before full commercial operations occur. Due to our unique modular development approach and configuration consisting of many mid-scale liquefaction trains, which are delivered and installed sequentially, it is necessary to commission and test our LNG facilities sequentially over a longer period of time than traditional LNG facilities with substantially fewer, larger-scale liquefaction trains. The commissioning of the liquefaction trains at our facilities begins while portions of our facilities remain under construction.

This important reliability and technical requirement results in earlier production of LNG than with traditional LNG facilities. We believe this earlier production of LNG positions us to produce a substantial number of commissioning cargos for each of our LNG projects, generating proceeds that may be used to support any remaining construction work or fund subsequent projects and future growth. As an example of this, on March 1, 2022, we announced the successful loading and departure of our first cargo of LNG from the Calcasieu Project, just over two and a half years from our final investment decision for the Calcasieu Project. Similarly, on December 26, 2024, we announced the successful loading and departure of our first cargo of LNG from the Plaquemines Project, just over two and a half years from our final investment decision for Phase 1 of the Plaquemines Project.

LNG commissioning cargos are sold to various customers under master SPAs, either as single cargos or as strips of multiple cargos to be loaded over a period of time, and are based on spot and/or forward prices, generally consisting of a liquefaction fee and a variable commodity charge, at the time of execution. As a result, the amount of revenue we are able to generate from such sales of commissioning cargos has differed, and will likely continue to differ, from period to period and from project to project, and such differences could be material.

LNG Sales – Post-COD SPAs

The project companies for the Calcasieu Project, the Plaquemines Project and the CP2 Project have signed LNG sales and purchase agreements, or SPAs, to sell LNG based on a predetermined pricing formula that commences after we achieve the commercial operation date, or COD, of the relevant project or phase thereof. Under our post-COD SPAs, customers will purchase LNG from us for a price consisting of a fixed facility charge (a portion of which is subject to an annual adjustment for inflation) per MMBtu of LNG, plus a variable commodity charge equal to at least 115% of Henry Hub per MMBtu of LNG. In certain circumstances, customers may elect to cancel or suspend deliveries of LNG cargos, but they will still be required to pay the fixed fee (but not the variable commodity charge) with respect to contracted volumes that are not delivered as a result of such cancellation or suspension. Under each such post-COD SPA, COD does not occur unless the applicable project company has notified such customer that (i) all of the project's facilities have been completed and commissioned, including any ramp up period, and (ii) the project is capable of delivering LNG in sufficient quantities and necessary quality to perform all of its obligations under such post-COD SPA.

As of December 31, 2024, we have executed 39.25 mtpa of such post-COD SPAs with a well recognized set of third party customers that we believe constitute one of the strongest portfolios of institutional LNG buyer credits in the world. Approximately 95% of our contracted post-COD SPAs – or 37.45 mtpa of such 39.25 mtpa – are 20-year fixed price agreements, providing a long-term stream of contracted cash flow. We have also executed 1.8 mtpa of post-COD SPAs on a short- and medium-term basis and we plan to continue to optimize our portfolio, balancing profit, duration, and risk.

Our third-party post-COD SPAs as of December 31, 2024 represent expected total contracted revenue of approximately $107 billion over the life of such SPAs. Our total contracted revenue is illustrative only and is based on a number of important assumptions. See Item 1A.—*Risk Factors*—*Risks Relating to Our Business—Total contracted revenue is based on certain assumptions and is presented for illustrative purposes only and actual sales under our SPAs may differ materially from such illustrative operating results* of this Form 10-K. The weighted average life of all of our post-COD SPAs is approximately 19 years.

Excess Capacity

LNG projects are typically able to achieve production beyond their guaranteed nameplate capacities. For many traditional large international stick-built projects, generating additional production capacity generally requires substantial incremental equipment and construction, with associated injections of capital. By comparison, we believe our projects will have the potential to produce materially beyond their nameplate capacities, with modest incremental capital investment because of our modular design as well as redundancy features inherent in our project design.

We aim to construct and maintain LNG facilities that are capable, in most cases, of producing excess capacity of at least 30% of their guaranteed nameplate capacity, which provides the potential for additional cash proceeds from our projects. Any such excess capacity will generally be available to us to sell on a short-, medium-, or long-term basis, providing flexibility to optimize pricing.

With respect to the Calcasieu Project, our inaugural project, we expect to produce excess capacity of slightly less than 30% of its nameplate capacity and we have received FERC approval for a maximum production capacity of 12.4 mtpa. With respect to the Calcasieu Project, any excess capacity above the nameplate capacity of 10.0 mtpa will be sold to VG Commodities under an Intercompany Excess Capacity SPA. We have contracted to resell a portion of the Calcasieu Project excess capacity that is sold to VG Commodities to a third-party pursuant to a long-term SPA. With respect to the Plaquemines Project, any excess capacity above the nameplate capacity of 13.3 mtpa for Phase 1 or above the nameplate capacity of 6.7 mtpa for Phase 2 will be sold to VG Commodities under the applicable Intercompany Excess Capacity SPA (one per phase). LNG sold under such Intercompany Excess Capacity SPAs can, to the extent not previously committed to third parties, be resold to third party customers at our discretion under short-, medium- or long-term contracts, providing the flexibility to optimize pricing and capture additional revenue on an ongoing basis after COD for each of Phase 1 and Phase 2, at price levels that we expect will typically exceed the fixed fee prices secured under the Plaquemines Foundation SPAs. We expect to enter into similar Intercompany Excess Capacity SPAs for our other projects under development.

Our Complementary Assets

Pipeline Projects

We are in the advanced stages of development to establish complementary gas transportation for our development projects. As an example, we have partnered with WhiteWater Midstream, LLC, a Texas-based pipeline developer and operator, to jointly develop, permit, and site the approximately 190 mile Blackfin pipeline project, a long-haul 48-inch intrastate pipeline designed to facilitate the transportation of Permian sourced gas from the Matterhorn Express pipeline to certain interconnecting pipelines, including the CP Express Pipeline.

Shipping

In order to vertically integrate our business and expand our customer base to premium markets that have no or limited LNG transportation resources, we have contracted to acquire newbuild LNG tankers and have also chartered additional LNG tankers on a medium- and short-term basis. As of December 31, 2024, we have contracted to acquire nine LNG tankers, constructed by two of the premier shipbuilders in South Korea, of which two LNG tankers have already been delivered. The remaining LNG tankers are under construction and are scheduled to be delivered on a rolling basis through 2026.

We have also executed two medium-term and two short-term charters for additional LNG tankers, which were delivered in the second half of 2024, bringing our total shipping portfolio to a total of thirteen LNG tankers. We believe these LNG tankers will support our ability to optimize LNG marketing and sales and differentiate us from many other LNG exporters in North America.

LNG Regasification Capacity

We are pursuing opportunities to secure LNG regasification capacity in key import markets to support current and prospective customers and differentiate ourselves from other LNG exporters in North America. As part of this initiative, through our wholly-owned subsidiary, VG LNG Marketing, LLC, we have acquired firm regasification facility capacity at the largest LNG regasification terminal in Europe, Grain LNG in the United Kingdom. We have contracted to import 42 LNG cargos per year from approximately 2029 until 2045 (apart from a limited period).

Additionally, we have secured approximately 1 mtpa of LNG regasification capacity at the new Alexandroupolis LNG receiving terminal in Greece for five years, which is expected to begin in October 2025. Our capacity accounts for approximately 25% of the total terminal capacity at Alexandroupolis, or approximately 12 LNG cargos annually.

We believe these contracted capacities will allow us to supply LNG and regasified natural gas directly into the European market to current and additional downstream customers.

Carbon Capture and Sequestration Initiative

In May 2021, we announced plans for carbon capture and sequestration, or CCS, facilities at or near the Calcasieu Project and Plaquemines Project sites that will be designed to compress CO_2 emissions from these projects and subsequently inject it into subsurface saline aquifers near the project sites, where it would be permanently stored. We plan to implement or utilize such CCS facilities at our other projects as well, such as the CP2 Project, the CP3 Project and the Delta Project, which are located nearby the Calcasieu Project and Plaquemines Project. We have conducted extensive studies to confirm the feasibility of the CCS facilities and have leased approximately 27,000 acres of pore space with the State of Louisiana. In July 2023, we submitted an application to the U.S. EPA for a Class VI well permit in respect of the Calcasieu Project and CP2 Project. We are in the process of completing the remaining applications for regulatory approval in respect of our current projects.

Our Liquefaction and Export Projects

Calcasieu Project

Calcasieu Project	
Project location:	
Site	Approximately 432 acres in Cameron Parish, Louisiana
Property rights	Ground leases for 30 years, with options to extend to 70 years
Deep-water frontage	Approximately 1.0 mile
Project design:	
Expected nameplate capacity	10.0 mtpa
Expected peak production capacity	Up to 12.4 mtpa
Potential bolt-on expansion incremental capacity	Up to 4.5 mtpa(1)
Liquefaction system	18 liquefaction trains
LNG storage	2 × 200,000 cubic meter cryogenic LNG storage tanks
Power supply	1 power island system (with a capacity of 620 MW nominal / 720 MW peak and consisting of 5 gas turbine generators and 2 steam turbine generators along with related equipment)
Gas pre-treatment system	3 units, each designed to support 50% of the expected nameplate capacity (1 redundant unit)
Berths	2 berths, each designed to accommodate vessels of up to 185,000 cubic meters in capacity
Lateral pipeline	Approximately 24-mile long lateral
Key permits:	
FERC approval	12.4 mtpa (February 2019 and September 2023)
DOE approval – FTA Nations	12.4 mtpa (September 2013 and April 2022)(2)
DOE approval – Non-FTA Nations	12.0 mtpa (March 2019)(2)(3)
Project timeline:	
Final investment decision / financial closing	August 2019
First LNG production	January 2022
Anticipated COD	April 15, 2025

(1) Potential bolt-on expansion opportunity based on facility capacity, scale, location and infrastructure. Subject to regulatory approval, among other things, and may change based on design considerations, regulatory review process, engagement with contractors and other factors.
(2) Cumulative exports to FTA Nations and Non-FTA Nations cannot exceed the permitted capacity as authorized by the FERC.
(3) Our request to increase the authorized level of exports to Non-FTA Nations from 12.0 mtpa to 12.4 mtpa is still pending. See —*Governmental Regulation—DOE Export Authorizations—Calcasieu Project.*

Project Construction and Commissioning

Construction of the Calcasieu Project is substantially complete and the project is currently undergoing a multi-faceted commissioning program to complete the facility's components, bring them to design specification and establish reliable and safe facility-wide operating conditions and to prepare for the commencement of lender-required performance reliability testing. Significant work related to commissioning, carryover completions, and rectification is ongoing and includes remedying unexpected challenges with equipment reliability identified during the first-time implementation of our innovative design and configuration, and reliability testing. We believe such work will need to be completed before certain components operate as intended and the facility can be fully commercially operable, and COD can occur. As of the date of this Form 10-K, we have completed substantial remediation work on the heat recovery steam generators, or HRSGs, of the power island system that was necessitated by the manufacturer of such equipment, General Electric, having implemented a change in method of fabrication that led to substantial leaking that was identified during commissioning tests. As of December 31, 2024, among the other ongoing rectification work, our gas pre-treatment units underperformed and were not able to pass their required performance tests. In January 2025 and February 2025, pre-treatment units "A" and "C" passed their required performance tests, respectively, though we are validating the test results for unit "C" with the independent engineer appointed by the lenders under the Calcasieu Pass Credit Facilities. We continue to engage in remediation efforts with UOP, the manufacturer, to improve pre-treatment unit "B" so that it will achieve the designed levels of performance and redundancy and pass its required performance tests.

We are targeting to complete all remediation work and achieve COD on April 15, 2025, after the project has completed its commissioning process and testing and is capable of safely and reliably producing its designed nameplate levels of LNG volumes.

As of December 31, 2024, the Calcasieu Project executed approximately 25.2 million work hours with a TRIR of 0.10. This safety performance far exceeds the national average for the industry of 1.9 for 2023.

Commissioning LNG Sales

Due to our unique project configuration (which includes many mid-scale liquefaction trains, which are delivered and installed sequentially) and development approach, it is necessary to commission and test our LNG facilities sequentially over a longer period of time than traditional LNG facilities with substantially fewer, larger-size liquefaction trains. This important reliability and technical requirement has resulted in the production of LNG starting earlier in the construction schedule than at traditional LNG facilities, and in far greater quantities – requiring us to produce a substantial number of commissioning cargos at the Calcasieu Project. Despite the longer than expected commissioning process at the Calcasieu Project due to certain unexpected challenges with equipment reliability that we are in the process of remediating, during the year ended December 31, 2024, the Calcasieu Project exported 140 LNG commissioning cargos. Pursuant to our project financing arrangements, a portion of the proceeds from the sale of these LNG commissioning cargos is held in cash reserve accounts in an amount we expect to be necessary to complete the project and achieve COD under the Calcasieu Foundation SPAs. As of December 31, 2024, we had an aggregate of $395 million of cash in reserve accounts at the Calcasieu Project, of which approximately $226 million is reserved for debt service.

Post-COD Contracts

Offtaker	MTPA	Tenor
Calcasieu Foundation SPAs		
Shell NA LNG LLC	2.0	20 Years
BP Gas Marketing Limited	2.0	20 Years
Orlen S.A.	1.5	20 Years
Edison S.p.A	1.0	20 Years
Galp Trading, S.A.	1.0	20 Years
Repsol LNG Holdings, S.A.	1.0	20 Years
Total contracted mtpa of Calcasieu Foundation SPAs(1)	**8.5**	
Other post-COD SPAs		
China International United Petroleum & Chemicals Co., Ltd.	1.0	3 Years
CNOOC Gas and Power Singapore Trading & Marketing Pte. Ltd.	0.5	5 Years
Total contracted nameplate mtpa of post-COD SPAs	**10.0**	

(1) Approximately 85% of the Calcasieu Project's expected 10.0 mtpa nameplate capacity.

We have entered into six 20-year take-or-pay, post-COD SPAs, or the Calcasieu Foundation SPAs, on an FOB basis, which means that the title to the LNG will transfer at the time our customers take delivery at our facilities. Consequently, our customers under our FOB SPAs will bear the risk of loss during transport and the cost of shipping the LNG cargo. The majority of these offtakers have investment grade credit ratings.

The obligation to make LNG available under the Calcasieu Foundation SPAs commences from the occurrence of COD, which is an identical requirement for all six SPAs and a typical construct within the LNG industry. To the extent of any shortfall in supply, we will pay the applicable counterparty to an SPA an amount for shortfall based on a pre-determined formula that takes into account the replacement price or market price for LNG, among other specified factors. This requirement to financially address shortfalls over the 20-year life of the Calcasieu Foundation SPAs underpins the focus on redundancy and reliability to be demonstrated as part of the commissioning phase of construction, prior to achieving COD.

The Calcasieu Foundation SPAs include termination rights in favor of the customer if, among other things, COD did not occur by March 2024, as may be extended in certain circumstances (including, among other things, in connection with a *force majeure* event). As a consequence of the occurrence of one such force majeure event, as further described below, the deadline for COD in such SPAs would be extended and we currently anticipate that such customers will not be entitled to terminate as a result of failure to designate COD until June 2025. We have notified all of our customers under the Calcasieu Project post-COD SPAs of the anticipated delay to COD, indicating that such delay resulted from a *force majeure* event. All of such customers have questioned whether the delay constitutes a *force majeure* event under the contract, in which case they would have a right to terminate their SPAs, generally for a limited duration of time, if COD did not occur by March 2024, and certain of our customers have disputed the validity of our declaration of *force majeure* in their respective arbitration proceedings. For more information see Item 1A.—*Risk Factors*—*Risks Relating to Our Business—Our customers or we may terminate our SPAs if certain conditions are not met or for other reasons* of this Form 10-K. As we continue to commission the facility, we aim to continue to produce commissioning cargos of LNG for export in accordance with all regulatory requirements and subject to the heat recovery steam generator and gas pre-treatment remediation work and other repairs being conducted while the site is made ready for reliability testing. In February 2025, we notified all of our customers that COD for the Calcasieu Project is anticipated to occur on April 15, 2025.

In addition to such 20-year Calcasieu Foundation SPAs, we have entered into a fixed-price three-year take-or-pay SPA for 1 mtpa of the Calcasieu Project's expected nameplate capacity with Unipec (a subsidiary of Sinopec) and a fixed-price five-year take-or-pay SPA for 0.5 mtpa of the Calcasieu Project's expected nameplate capacity with CNOOC Gas and Power Singapore Trading & Marketing Pte. Ltd., both on similar terms and conditions as the long-term Calcasieu Foundation SPAs.

We expect that any excess LNG produced by the Calcasieu Project above the nameplate capacity of 10.0 mtpa will be sold to VG Commodities under an Intercompany Excess Capacity SPA for the Calcasieu Project. VG Commodities is party to an LNG sales and purchase agreement, or the VG Commodities BP SPA, with BP Gas Marketing Limited, or BP, pursuant to which, once COD occurs under the Intercompany Excess Capacity SPA for the Calcasieu Project, VG Commodities has contracted to resell at least 50% of the LNG generated by the Calcasieu Project in excess of its nameplate capacity (subject to an annual cap at the option of the buyer). The VG Commodities BP SPA is structured as a 20-year, FOB sales contract, under which BP is required to pay VG Commodities a purchase price for LNG delivered to BP based on a simulated net-back price, which is designed to reflect a profit margin (after deducting related costs) realized from downstream sales of LNG.

Plaquemines Project

Plaquemines Project	Phase 1	Phase 2
Project location:		
Site	Approximately 630 acres in Plaquemines Parish, Louisiana	
Property rights	Ground lease for 30 years, with options to extend to 70 years	
Deep-water frontage	Approximately 1.3 miles	
Anticipated project design:(1)		
Expected nameplate capacity	13.3 mtpa	6.7 mtpa
Expected peak production capacity	Up to 27.2 mtpa(1)	
Potential bolt-on expansion incremental capacity	Up to 18.6 mtpa(2)	
Liquefaction system	12 blocks (24 liquefaction trains)	6 blocks (12 liquefaction trains)
LNG storage	2 × 200,000 cubic meter cryogenic LNG storage tanks	2 × 200,000 cubic meter cryogenic LNG storage tanks
Power supply	2 power island systems (each with a capacity of 620 MW nominal / 720 MW peak and consisting of 5 gas turbine generators and 2 steam turbine generators along with related equipment)	
Gas pre-treatment system	4 units (1 redundant unit)	2 units (1 incremental redundant unit)
Berths	2 berths, each designed to accommodate vessels up to 200,000 cubic meters in capacity	1 berth, designed to accommodate vessels up to 200,000 cubic meters in capacity
Lateral pipelines	Two laterals (one approximately 15-mile long lateral and one approximately 12-mile long lateral)	
Key permits:		
FERC approval	27.2 mtpa (February 2025)	
DOE approval – FTA Nations	27.2 mtpa (June 2022)(3)	
DOE Non-FTA Nations	24.0 mtpa (October 2019)(1)	
Anticipated project timeline:		
Final investment decision / financial closing	May 2022	March 2023
First LNG production	December 2024	
Targeted COD	Q4 2026	Mid-2027

(1) Our request to increase the authorized level of exports to Non-FTA Nations from 24.0 mtpa to 27.2 mtpa is still pending. See —*Governmental Regulation—DOE Export Authorizations—Plaquemines Project* of this Form 10-K.

(2) Potential bolt-on expansion opportunity based on facility capacity, scale, location and infrastructure. Subject to regulatory approval, among other things. The anticipated timing to implement this expansion opportunity may change based on design considerations, regulatory review process, engagement with contractors and other factors. In addition, implementation of the full amount of potential bolt-on expansion capacity is subject to our ability to secure additional natural gas, pipelines and pipeline transportation capacity. On March 6, 2025, we submitted to FERC a request to initiate the pre-filing process for additional facilities to provide 18.6 mtpa of incremental bolt-on expansion peak production capacity. We aim to file a formal application with FERC in the second half of 2025 and are targeting FID in mid-2027.

(3) Cumulative exports to FTA Nations and Non-FTA Nations cannot exceed the permitted capacity as authorized by the FERC.

Project Construction and Commissioning

The Plaquemines Project is being constructed pursuant to two EPC contracts, one per phase, or the Plaquemines EPC Contracts, that we entered into with KZJV, LLC, or KZJV, a limited liability company that is owned by KBR EPC Member and Zachry Industrial. Under the Plaquemines EPC Contracts, VGPL is responsible for executing or directly managing significant scopes of work. Baker Hughes, UOP and CB&I are each providing and constructing the mid-scale, factory-built liquefaction trains and power island systems, the pre-treatment system, and storage tanks, respectively.

As of December 31, 2024, 28 of the 36 liquefaction trains were delivered to the site. In addition, the Gator Express Pipeline achieved mechanical completion in October 2023 and its laterals were placed in service by FERC in May 2024 and December 2024. While construction remains ongoing, portions of the facility have commenced initial commissioning activities. Our gradual commissioning process starts with addressing identified operational deficiencies, testing individual components and eventually extends to encompass testing and tuning our entire fully-integrated facilities. As an example, one issue that has arisen relates to substantial delays in the operation of our combined cycle power island system. To mitigate such delays, we have permitted and incorporated 400 MW of temporary power at the Plaquemines facility. This allows us to progress commissioning efforts, including the production and sale of commissioning cargos while we complete the construction of our combined cycle power plants.

We currently estimate that the total project costs for the Plaquemines Project will be approximately $23.3 billion to $23.8 billion, including EPC contractor profit and contingency, owners' costs and financing costs. Of the total project costs for the Plaquemines Project, approximately $19.8 billion had been paid for as of December 31, 2024. Our estimated total project cost remaining is based upon our project cost experiences with the Calcasieu Project and with the Plaquemines Project to date and reflects the current inflationary environment. However, the costs to complete the Plaquemines Project have increased in the past, and may increase further in the future, potentially materially, compared to our current estimates as a result of many factors. Further, these cost estimates do not include the cost of any potential bolt-on capacity at the Plaquemines Project, nor do they reflect the potential impact of any new tariffs that have been announced or implemented since December 31, 2024, or that may be implemented in the future. As a result, the actual project costs for the Plaquemines Project may be materially higher than our current estimates. See Item 1A.—*Risk Factors—Risks Relating to Our Projects and Other Assets—Our estimated costs for our projects have been, and continue to be, subject to change due to various factors* of this Form 10-K.

As of December 31, 2024, the Plaquemines Project had executed approximately 68.8 million work hours with a TRIR of 0.21. This safety performance far exceeds the national average for the industry of 1.9 for 2023.

Commissioning LNG Sales

Although designed to be twice as large as the Calcasieu Project on a nameplate basis, the Plaquemines Project utilizes a similar project configuration and development approach to the Calcasieu Project. In contrast to traditional LNG facilities that are constructed by a single EPC contractor and include substantially fewer, larger-size liquefaction trains, our project design and configuration utilizes pioneering, mid-scale, factory-made liquefaction trains and other discrete systems and equipment, which require an extended commissioning period. Given this longer and gradual commissioning period, we expect to produce a substantial number of commissioning cargos. This production occurs during the period in which additional components of the relevant phase are brought into operation, completed and tested (including, if necessary, performing completion and rectification work to address unexpected performance deficiencies), to ensure the project is completed and achieves the performance levels necessary for stable, reliable long-term operations to supply LNG under the project's post-COD SPAs.

In December 2024, we began to produce LNG at the Plaquemines Project and announced the successful loading and departure of our first commissioning cargo. As of December 31, 2024, the Plaquemines Project had exported one LNG commissioning cargo. This cargo was sold to VG Commodities and ultimately delivered and sold by VG Commodities to an end customer in January 2025.

Post-COD Contracts

Offtaker	MTPA	Tenor
Plaquemines Foundation SPAs – Phase 1		
Orlen S.A.	4.0	20 Years
China Petroleum & Chemical Corp. (1)	4.0	20 Years
Shell NA LNG LLC	2.0	20 Years
CNOOC Gas and Power Singapore Trading & Marketing Pte. Ltd.	2.0	20 Years
Électricité de France, S.A.	1.0	20 Years
Plaquemines Foundation SPAs – Phase 2		
Chevron U.S.A. Inc.	1.0	20 Years
ENBW Energie Baden-Wurttemberg AG	1.0	20 Years
ExxonMobil LNG Asia Pacific	1.0	20 Years
Petronas LNG LTD	1.0	20 Years
NFE North Trading, LLC	1.0	20 Years
China Gas Hongda Energy Trading Co., Ltd.	1.0	20 Years
Excelerate Gas Marketing, Limited Partnership	0.7	20 Years
Total contracted mtpa of Plaquemines Foundation SPAs(2)(3)	**19.7**	

(1) China Petroleum & Chemical Corp. has signed two separate LNG SPAs for an aggregate supply of 4.0 MTPA.
(2) Approximately 98.5% of the Plaquemines Project's expected 20.0 mtpa nameplate capacity.
(3) Chart does not include the post-COD SPA with Inpex Energy Trading Singapore Pte. Ltd., which is described further below.

As of December 31, 2024, we have entered into thirteen 20-year take-or-pay, post-COD SPAs in connection with the Plaquemines Project, or the Plaquemines Foundation SPAs. The majority of these offtakers have investment grade credit ratings.

The obligation to make LNG available under these SPAs commences from the occurrence of COD, which is bifurcated by Phase 1 or Phase 2, depending on the SPA. All of these SPAs are structured to be delivered on an FOB basis, with the exception of one Phase 1 SPA for 1.2 mtpa, which is structured to be delivered on a DPU basis – requiring us to ship, deliver, and unload LNG to our customer's designated import facilities. Similar to the Calcasieu Foundation SPAs, the Plaquemines Foundation SPAs include termination rights in favor of the customer if, among other things, COD does not occur by May 2027 or March 2028 for the Phase 1 and Phase 2 SPA, respectively, as may be extended in certain circumstances (including, among other things, in connection with a *force majeure* event).

In addition to the Plaquemines Foundation SPAs, we have entered into a short-term, post-COD SPA for 0.3 mtpa of the Plaquemines Project's expected nameplate capacity with Inpex Energy Trading Singapore Pte. Ltd. on an FOB basis, on similar terms and conditions as the Plaquemines Foundation SPAs.

Any excess LNG produced by the Plaquemines Project above the nameplate capacity of 13.3 mtpa for Phase 1 or above the nameplate capacity of 6.7 mtpa for Phase 2 will be sold to VG Commodities under the applicable Intercompany Excess Capacity SPA.

CP2 Project

CP2 Project	Phase 1	Phase 2
Project location:		
Site	Approximately 1,150 acres in Cameron Parish, Louisiana	
Property rights	Ground leases for 30 years, with options to extend to 70 years	
Deep-water frontage	Approximately 1.0 mile	
Anticipated project design:[(1)]		
Expected nameplate capacity	14.4 mtpa	5.6 mtpa
Expected peak production capacity	Up to 28.0 mtpa	
Potential bolt-on expansion incremental capacity	Up to 18.6 mtpa[(2)]	
Liquefaction system	13 blocks (2 liquefaction trains per block)	5 blocks (2 liquefaction trains per block)
LNG storage	2 × 200,000 cubic meter cryogenic LNG storage tanks	2 × 200,000 cubic meter cryogenic LNG storage tanks
Power supply	2 power island systems (each with a capacity of 620 MW nominal / 720 MW peak and consisting of 5 gas turbine generators and 2 steam turbine generators along with related equipment)	
Gas pre-treatment system	4 units (1 redundant unit)	2 units (1 incremental redundant unit)
Berths	2 berths, each designed to accommodate vessels up to 200,000 cubic meters in capacity	
Lateral pipelines	Two laterals (one approximately 6-mile long lateral and one approximately 85-mile long lateral)	
Key permits:		
FERC approval	June 2024 (subject to partial supplemental review)[(3)]	
DOE approval – FTA Nations	28.0 mtpa (April 2022)	
DOE Non-FTA Nations	Application filed December 2021 (pending approval)	
Anticipated project timeline:		
Targeted final investment decision / financial closing	Mid-2025	Mid-2026
Targeted COD	Mid-2029	Mid-2030

(1) Anticipated based on capacity, scale, location and infrastructure. Subject to regulatory approval, among other things, and may change based on design considerations, regulatory review process, engagement with contractors, and other factors.

(2) Potential bolt-on expansion opportunity based on facility capacity, scale, location and infrastructure. Subject to regulatory approval, among other things. The anticipated timing to implement this expansion opportunity may change based on design considerations, regulatory review process, engagement with contractors and other factors.

(3) The FERC issued its order authorizing the CP2 Project in June 2024. However, on November 27, 2024, FERC issued an order on rehearing that partially "set aside" its prior analysis of the cumulative air impacts of emissions of nitrogen dioxide (NO2) and particulate matter less than 2.5 micrometers (PM2.5) and to prepare a supplemental Environmental Impact Statement concerning that topic and to address it along with certain other air quality issues in a future order. FERC also announced that, due to its initiation of supplemental environmental review, it will not issue authorizations to proceed with construction until FERC issues a further merits order. On February 7, 2025, FERC issued a draft supplemental Environmental Impact Statement, concluding that the project will have no significant cumulative air quality impacts. Public comments on the draft Environmental Impact Statement are due by March 31, 2025, and FERC's schedule provides for the final Environmental Impact Statement to be issued by May 9, 2025. Project opponents have also appealed the FERC authorization to the U.S. Court of Appeals for the D.C. Circuit. In response to FERC's order on rehearing, the D.C. Circuit on December 13, 2024, granted an unopposed motion by FERC to hold the appeal in abeyance, which will delay briefing of the D.C. Circuit appeal. See Item 1A.—*Risk Factors—Risks Relating to Regulation and Litigation—We may fail to receive the required approvals and permits from governmental and regulatory agencies for our projects* of this Form 10-K.

Project Engineering, Procurement, and Construction

We have completed substantial engineering, procurement, manufacturing, and off-site construction work for the CP2 Project in advance of a final investment decision, which remains subject to certain regulatory approvals, market and other conditions. See *—Governmental Regulation* and Item 1A.*—Risk Factors—Risks Relating to Regulation and Litigation—We may fail to receive the required approvals and permits from governmental and regulatory agencies for our projects* of this Form 10-K.

For the CP2 Project, we anticipate that we will seek to manage additional scopes of work by directly taking on incremental oversight, contract management and coordination responsibilities, based on lessons learned and the relationships we have fostered with construction and fabrication subcontractors while developing the Calcasieu Project and the Plaquemines Project. As of December 31, 2024, we have entered into a number of key contracts to develop and construct the CP2 Project. Such contracts include liquefaction train system and power island system purchase orders with Baker Hughes and an EPC contract for construction of Phase 1 of the CP2 Project, or the CP2 Phase 1 EPC Contract, with Worley Field Services Inc., or Worley. We have also entered into contracts for other discrete portions of the facility, including for LNG storage tanks, gas pre-treatment system licensing, engineering, and procurement agreements and for the construction of the CP2 Project's perimeter wall.

We currently estimate that the total project costs for the CP2 Project will range between approximately $27.0 billion and $28.0 billion, including EPC contractor profit and contingency, owners' costs and financing costs, substantially all of which has yet to be funded. Our estimated total project cost is based upon our project cost experiences with the Calcasieu Project and the Plaquemines Project and reflects the current inflationary environment and that the CP2 Project's pipelines are expected to be longer than the pipelines for the Calcasieu Project and the Plaquemines Project. However, we have not yet entered into an EPC contract for Phase 2 of the CP2 Project or certain other key contracts for the development and construction of the CP2 Project. As a result, there can be no assurance that we will be able to enter into such contracts on similar terms to those for the Calcasieu Project, the Plaquemines Project, and/or Phase 1 of the CP2 Project, as applicable. Further, these cost estimates do not include the cost of any potential bolt-on capacity at the CP2 Project, nor do they reflect the potential impact of any new tariffs that have been announced or implemented since December 31, 2024 or that may be implemented in the future. In addition, certain regulatory approvals and permits must be obtained on a timely basis in order to construct and operate the project, and there can be no assurance that we can obtain and maintain the necessary regulatory approvals and permits to complete the CP2 Project on the anticipated schedule. Accordingly, the actual project costs for the CP2 Project may be materially higher than this estimate. Moreover, the anticipated costs to achieve completion of the CP2 Project have increased in the past, and may increase further in the future, potentially materially, compared to our current estimates as a result of many factors, including delays in construction or commissioning of the project or the execution of any repair or warranty work and change orders under or amendments to certain material construction contracts, including final terms of or amendments to any EPC contract for the CP2 Project, and/or other construction or supply contracts resulting from the occurrence of certain specified events that may give the applicable contractor or supplier the right to cause us to enter into change orders or resulting from changes with which we otherwise agree. See Item 1A.*—Risk Factors—Risks Relating to Our Projects and Other Assets—Our estimated costs for our projects have been, and continue to be, subject to change due to various factors* of this Form 10-K.

Post-COD Contracts

As of December 31, 2024, we have entered into eight 20-year take-or-pay, post-COD SPAs in connection with the CP2 Project, or the CP2 Foundation SPAs, on an FOB basis. These SPAs all relate to Phase 1 of the CP2 Project and equate to 9.25 mtpa of LNG, which is approximately 64% of the expected nameplate capacity for Phase 1 of 14.4 mtpa.

The obligation to make LNG available under these SPAs commences from the occurrence of COD. All of these SPAs are structured for delivery on an FOB basis. Similar to the Calcasieu Foundation SPAs and the Plaquemines Foundation SPAs, the CP2 Foundation SPAs include termination rights in favor of the customer and us if certain conditions precedent are not satisfied by us or waived by the customer by a certain date including that we receive all LNG export authorizations by that date. Such dates certain have passed in two of the CP2 Foundation SPAs and are upcoming in March 2025 in the remaining CP2 Foundation SPAs. As a result, we or some of our customers under the CP2 Foundation SPAs may decide to terminate their SPAs based on such deadlines having passed. See Item 1A.—*Risk Factors—Risks Relating to Our Business—Our customers or we may terminate our SPAs if certain conditions are not met or for other reasons* of this Form 10-K. We are negotiating extensions with all of the CP2 Foundation SPA customers related to these date certain deadlines. In addition, our customers also have other limited termination rights if, among other things, COD for Phase 1 does not occur by a date that is approximately 60 months from the satisfaction of such conditions precedent, as may be extended in certain circumstances (including, among other things, in connection with a *force majeure* event).

We expect that any excess LNG produced by the CP2 Project above the nameplate capacity of 14.4 mtpa for Phase 1 or above the nameplate capacity of 5.6 mtpa for Phase 2 will be sold to VG Commodities under an Intercompany Excess Capacity SPA (one per phase) to be entered into for the relevant phase.

CP3 Project

CP3 Project	Phase 1	Phase 2
Project location:		
Site	Approximately 840 acres in Cameron Parish, Louisiana	
Property rights	Ground lease for up to 70 years in total	
Deep-water frontage	Approximately 1 mile	
Anticipated project design(1):		
Expected nameplate capacity	30.0 mtpa (phase and plant configuration remains to be determined)	
Expected peak production capacity	Up to 42.0 mtpa	

(1) Anticipated based on capacity, scale, location and infrastructure, and may change based on design considerations, regulatory review process, engagement with contractors, and other factors. As of the date of this Form 10-K, no FERC and no DOE filings have been made and the necessary approvals for the CP3 Project have not been obtained. Accordingly, this is a target only, based on, among other things, anticipated timeframes for the receipt of the required DOE and FERC approvals. See *—Governmental Regulation* and Item 1A.—*Risk Factors—Risks Relating to Regulation and Litigation—We may fail to receive the required approvals and permits from governmental and regulatory agencies for our projects*.

Project Development

As of December 31, 2024, we have completed significant engineering studies and simulations, including certain marine berth simulations, in support of the project.

Although we have completed our initial consultation with FERC in December 2024, as of December 31, 2024, we had not initiated the pre-filing process for the CP3 Project with FERC or entered into definitive agreements with an EPC contractor or other key advisors and contractors necessary for the project's development and construction. However, we have ample capacity under the Baker Hughes Master Agreement to contract for the potential supply of liquefaction trains and power island systems, which we expect to utilize for the CP3 Project. We expect that the construction, commissioning and operational start-up of the liquefaction plant will be substantially similar to our other projects.

Delta Project

Delta Project	Phase 1	Phase 2
Project location:		
Site	Approximately 1,100(1) acres in Plaquemines Parish, Louisiana	
Property rights	Option to lease for up to 70 years	
Deep-water frontage	Approximately 0.6 miles	
Anticipated project design(2):		
Expected nameplate capacity	24.4 mtpa (phase and plant configuration remains to be determined)	
Expected peak production capacity	Up to 34.2 mtpa	
Potential bolt-on expansion incremental capacity	Up to 7.8 mtpa(3)	

(1) Location and acreage for project site may change based on project execution priorities, design considerations, regulatory review process, engagement with contractors, and other factors..

(2) Anticipated based on capacity, scale, location and infrastructure, and may change based on design considerations, regulatory review process, engagement with contractors, and other factors. As of the date of this Form 10-K, definitive FERC and DOE filings have not been made and the necessary approvals for the Delta Project have not been obtained. Accordingly, this is a target only, based on, among other things, anticipated timeframes for the receipt of the required DOE and FERC approvals. See *—Governmental Regulation* and Item 1A.—*Risk Factors*—*Risks Relating to Regulation and Litigation—We may fail to receive the required approvals and permits from governmental and regulatory agencies for our projects.*

(3) Potential bolt-on expansion opportunity based on facility capacity, scale, location and infrastructure. Subject to regulatory approval, among other things, and may change based on design considerations, regulatory review process, engagement with contractors and other factors.

Project Development

We initiated the pre-filing process for the Delta Project with FERC in April 2019; however, we have informed FERC that, if FERC confirms the acceptance of the potential bolt-on expansion at the Plaquemines Project into the NEPA pre-filing review process, we will withdraw the Delta Project from the pre-filing process. In addition, we have not yet entered into definitive agreements with an EPC contractor or other key advisors and contractors necessary for the project's development and construction. However, we have ample capacity under the Baker Hughes Master Agreement to contract for the potential supply of liquefaction trains and power island systems, which we expect to utilize for the Delta Project. We expect that the construction, commissioning and operational start-up of the liquefaction plant will be substantially similar to our other projects.

Natural Gas Supply and Transportation

Natural Gas Supply Portfolio Approach

To the extent we produce LNG for export pursuant to our existing SPAs, we are responsible for procuring natural gas and transporting it to the relevant facility for liquefaction. We have entered into a portfolio of natural gas supply agreements with domestic natural gas suppliers to supply feed gas to the Calcasieu Project and the Plaquemines Project, which we continue to expand to suit the needs of our projects. We also anticipate entering into long-term natural gas supply arrangements with large upstream gas producers that will integrate their gathering and processing facilities into our planned pipeline network and deliver natural gas to our project facilities for liquefaction. Assuming we are able to operate our projects at their expected peak production capacity, we anticipate that we will require approximately 1.9 Bcf/d of natural gas for the Calcasieu Project, 4.2 Bcf/d of natural gas for the Plaquemines Project, 4.3 Bcf/d of natural gas for the CP2 Project, 6.5 Bcf/d of natural gas for the CP3 Project, and 5.3 Bcf/d of natural gas for the Delta Project. These estimates do not account for any bolt-on expansions. We have constructed lateral pipelines to connect the Calcasieu Project and the Plaquemines Project to the ANR Pipeline Company, Texas Eastern Transmission LP, and Sabine Pipe Line systems, and the Columbia Gulf, Texas Eastern Transmission LP, and Tennessee Gas Pipeline systems, respectively. Similarly, we intend to construct pipelines to connect our other current projects and any other future projects we may seek to develop to major interstate and intrastate pipelines. In addition, as described below, we aim to own other natural gas pipelines that support or, when constructed, will support our production facilities. Such connections allow us to access highly liquid upstream supplies.

Natural Gas Transportation: Contracted Pipeline Capacity and Pipeline Development

We are developing, permitting, constructing and securing transport capacity agreements for midstream natural gas pipeline infrastructure that is intended to support our liquefaction growth strategy and help ensure stable and cost-effective access to the natural gas that fuels our LNG exports.

We have entered into a number of transport capacity agreements and related service agreements with interstate pipeline companies to provide the natural gas transportation to the Calcasieu Project and the Plaquemines Project. The Calcasieu Project and the Plaquemines Project were each sited and sized to facilitate ready connectivity to existing natural gas pipeline network infrastructure with the construction of short-run lateral pipelines. These lateral pipelines (the TransCameron Pipeline and the Gator Express Pipeline), and the major, third-party interstate pipelines to which they are connected, provide natural gas supply primarily from two major shale formations – the Haynesville and the Marcellus/Utica plays – though there is access to other U.S. shale basins though interconnects into the third-party interstate pipelines.

Our existing gas transportation agreements for the Calcasieu Project and the Plaquemines Project are long-term commitments of approximately 20 years from the commencement of service, with extension rights following the initial term.

We have acquired all of the land rights required to construct and operate the TransCameron Pipeline and the Gator Express Pipeline for the Calcasieu Project and the Plaquemines Project, respectively. We are also currently in the process of securing servitudes, rights of way, crossing agreements, and any permits necessary for us to construct the interstate and intrastate pipelines discussed below, lateral pipelines and related infrastructure required to interconnect the CP2 Project, the CP3 Project and the Delta Project with existing interstate and intrastate natural gas pipeline systems.

The TransCameron Pipeline is the lateral pipeline that delivers natural gas to the Calcasieu Project. The Calcasieu Project holds firm transport capacity of 2.35 TBtu/day on several pipeline systems delivering into its TransCameron supply header system including ANR Pipeline Company, Texas Eastern Transmission LP, and Sabine Pipe Line systems. Additionally, the Calcasieu Project holds firm transport capacity of 700,000 Dth/d, reducing to 625,000 Dth/d in April 2025, on the TC Louisiana Intrastate Pipeline, providing the ability to transport Haynesville production into ANR Pipeline for both supply security and beneficial pricing. The TransCameron Pipeline achieved substantial completion in April 2021 and final completion in July 2021 and has been commissioned and placed in service by FERC.

The Gator Express Pipeline is the lateral pipeline that delivers natural gas to the Plaquemines Project. The Plaquemines Project holds firm transport capacity of 4.225 TBtu/day on several pipeline systems delivering into its Gator Express supply header system including Columbia Gulf, Texas Eastern Transmission LP, and Tennessee Gas Pipeline systems. Additionally, the Plaquemines Project holds firm transport capacity of 575,000 Dth/d on the TC Louisiana Intrastate Pipeline, providing the ability to transport Haynesville production into Columbia Gulf for both supply security and beneficial pricing. The Gator Express Pipeline achieved mechanical completion in October 2023 and its laterals were placed in service by FERC in May 2024 and in December 2024.

The proposed CP Express Pipeline will deliver natural gas to the CP2 Project and will consist of 85.4 miles of 48-inch-diameter natural gas pipeline in Jasper and Newton Counties, Texas and Calcasieu and Cameron Parishes, Louisiana, and a 6.0-mile-long, 24-inch-diameter lateral off that mainline in northwest Calcasieu Parish. For the CP Express Pipeline we have secured an agreement, subject to FID of the CP2 Project, for firm transport capacity on the TC Louisiana Intrastate Pipeline LLC (1.4 TBtu/day expanding to 1.9 TBtu/day) to transport Haynesville production into the CP Express Pipeline in Louisiana. In addition, subject to CP2 Project requirements, we expect the CP

Express Pipeline will interconnect with additional upstream pipeline infrastructure that secures delivery of gas from additional production basins.

We are in the development and siting process to optimize the plans for the pipelines to support the potential bolt-on expansion for the Plaquemines Project, the CP3 Project and the Delta Project.

As we are expanding our development footprint with the CP2 Project, the CP3 Project and the Delta Project, these projects' production capacities are anticipated to require natural gas volumes that will support the construction of longer interstate and intrastate pipelines that provide incremental access and delivery capability from the Permian, Haynesville, Western Haynesville, Eagle Ford and mid-continent shale formations.

We plan to construct significant pipeline infrastructure, both independently and in partnership with certain qualified third parties, sufficient to source the required natural gas for these projects from primarily the Permian, Haynesville and Western Haynesville shale plays.

For example, we have partnered with WhiteWater Midstream, LLC, a Texas-based pipeline developer and operator, and through our wholly-owned subsidiary Venture Global Midstream Holdings, LLC, have entered into an agreement with WhiteWater Blackfin Holdings, LLC pursuant to which we have committed to jointly develop, permit, and site the 190 mile Blackfin pipeline project, which upon construction is expected to include a long-haul 48-inch intrastate pipeline designed to facilitate the transportation of Permian sourced gas from the Matterhorn Express pipeline to certain interconnecting pipelines, including the CP Express Pipeline. Under the agreement, we have agreed to fund certain construction and development costs and seek to arrange a financing to support the Blackfin pipeline project. We have secured firm transport capacity on Matterhorn Express Pipeline, LLC (2.0 TBtu/day, expanding to 3.3 TBtu/day) that will feed into the Blackfin pipeline.

We have also commenced early development activities for two additional long-haul pipeline projects to support our planned development projects. The first pipeline project is anticipated to be an approximately 291 mile, 48-inch intrastate pipeline in Louisiana that is designed to transport up to approximately 4.5 TBtu/day of natural gas from northeast Louisiana close to our projects located in Plaquemines Parish, including our contemplated expansion project at our Plaquemines Project. The second pipeline project is anticipated to be an approximately 644 mile, dual, 48-inch intrastate pipeline in Texas that is designed to transport up to approximately 6.5 TBtu/day of natural gas from the Permian Basin to Eastern Texas, which is proximate to our CP3 Project located in Cameron Parish, Louisiana.

Major Consultants and Contractors

In conjunction with our owner-led procurement and management approach, we are working with a team of consultants and contractors that assist us with the development, engineering, financing, construction, permitting, marketing and operation of our projects. The conventional approach utilized by developers for large-scale projects typically relies on a single, comprehensive EPC contract, delegating all or substantially all responsibility to construct a project to a single EPC contractor. In contrast, we decentralize the contracting approach for our projects and seek to manage key scopes of work directly with a collection of key contractors, each of which are experts in particular systems and equipment.

To implement our "design one, build many" approach, we have entered into the Baker Hughes Master Agreement that grants us the option to order significant quantities of liquefaction trains and power island systems for the projects that we develop. For each of our projects, we also enter into certain design, procurement, and construction contracts for other key equipment and facilities such as the pre-treatment system, LNG storage tanks, perimeter wall, and marine facilities. As of December 31, 2024, we have entered into the Calcasieu EPC Contract, the Plaquemines EPC Contracts, the CP2 Phase 1 EPC Contract, the Baker Hughes Master Agreement, purchase orders with Baker Hughes, and several construction or procurement contracts for other key equipment and components of the Calcasieu Project, the Plaquemines Project and the CP2 Project. To the extent not yet in place, we aim to negotiate and to enter into agreements on similar terms to those for the Calcasieu Project and the Plaquemines Project for the construction of our development projects.

Baker Hughes

The Baker Hughes Master Agreement provides for the supply of substantial incremental nameplate liquefaction and power equipment well in excess of the expected 104.4 mtpa nameplate capacity of our current project portfolio. Subject to our compliance with the Baker Hughes Master Agreement, such incremental equipment can be utilized for our development projects and any bolt-on expansions or additional projects that we may seek to develop in the future. Under the Baker Hughes Master Agreement, Baker Hughes is required to supply such equipment at an agreed upon price and schedule with reserved manufacturing capacity.

Purchase orders under the Baker Hughes Master Agreement contain terms and conditions, scope of supply, delivery schedule and performance tests and performance guarantees. We are limited under this agreement from contracting with an alternate equipment supplier to Baker Hughes, even in the event our preference is to do so. All of the liquefaction purchase orders and power island system purchase orders for the Calcasieu Project, the Plaquemines Project, and the CP2 Project follow the terms and conditions specified in the applicable form purchase order included in the Baker Hughes Master Agreement.

Under the Baker Hughes Master Agreement and related purchase orders, Baker Hughes has committed to satisfy key performance, reliability and LNG quality guarantees for the liquefaction and, as applicable, power equipment it supplies. In particular, if the relevant equipment fails to pass specified performance tests, then Baker Hughes is required to perform all work necessary to cause those systems to successfully pass the performance tests at its own expense or pay liquidated damages under certain performance guarantees.

Baker Hughes has agreed to reserve dedicated manufacturing capacity for the required components for our projects, which is sufficient to cover our five existing and contemplated projects, as well as incremental capacity that can be utilized for bolt-on expansions or future projects. The obligation to reserve manufacturing capacity expires in a staggered manner if we do not execute definitive purchase orders for the applicable portions of these components by certain mutually agreed dates. We have already executed the necessary purchase orders for the Calcasieu Project, the Plaquemines Project, and the CP2 Project and, based on our anticipated project schedule and barring unforeseen delays, we currently expect that we will be in a position to deliver the purchase orders for the CP3 Project, the Delta Project, or for any potential bolt-on expansions to Baker Hughes by the applicable deadlines in the Baker Hughes Master Agreement, as those deadlines may be amended from time to time.

In addition to the reservation of manufacturing capacity, the Baker Hughes Master Agreement contains an agreed upon price structure and schedule for the equipment that Baker Hughes is obligated to supply, except for certain alternative configurations of power island systems, in which case the agreed upon price structure and schedule is adjusted. The Baker Hughes Master Agreement generally provides for various staggered delivery dates for the first delivery of components, subject to the determination of final technical details of the equipment supplied as well as the terms of their respective purchase orders. Furthermore, we and Baker Hughes have agreed upon the pricing framework for the various components required for our liquefaction systems, which remain subject to adjustments based on changes to the scope of equipment and/or operations, negotiations in good faith and/or other modifications pursuant to the terms and conditions of the purchase orders when delivered.

The Baker Hughes Master Agreement includes pre-negotiated forms of purchase orders for the supply of liquefaction systems and power plants. Each purchase order is required to contain terms and conditions, scope of supply, delivery schedule and performance tests and performance guarantees. Unless and until we execute purchase orders for the equipment and issue notices to proceed under those orders, neither we nor Baker Hughes has any binding obligations with respect to the supply of any equipment under the Baker Hughes Master Agreement. Once we execute any purchase order with Baker Hughes for the supply of equipment, we may terminate that purchase order at our discretion. However, if we do terminate any purchase order, we are required to pay a termination fee to Baker Hughes, which is intended to reflect the out-of-pocket costs that Baker Hughes expects to incur in connection with such termination that it is not able to mitigate. As a result, if termination occurs in the mid-to-late stage of Baker Hughes' performance of a purchase order, the termination fee payable in respect of that purchase order would approach, but would not exceed, the contract price for that purchase order.

In addition, we have the right under the Baker Hughes Master Agreement to require Baker Hughes to enter into long-term service agreements on specified terms with respect to long-term maintenance, repair, and servicing of the liquefaction, power, and booster compressor equipment it supplies. We exercised such right for the Calcasieu Project and the Plaquemines Project and signed such long-term service agreements with Baker Hughes in December 2022 and December 2024, respectively. Moreover, pursuant to the form long-term service agreement and the Calcasieu Project's long-term service agreement, Baker Hughes is required to provide a long-term availability guarantee whereby Baker Hughes guarantees that the equipment it supplies will reach a minimum annual operating availability. If the equipment Baker Hughes supplies is unable to reach the specified operating availability, liquidated damages will be payable by Baker Hughes. To the extent the liquefaction system reaches an operating availability in excess of a certain level, we would be obligated under any such long-term service agreement to pay Baker Hughes a bonus based upon the amount of such excess. Both Baker Hughes' and our respective obligations under this long-term service agreement would be subject to certain agreed limitations on liability.

EPC Contracts

Our project companies directly negotiate and contract with, as well as oversee and manage, our equipment vendors for the delivery of the majority of the critical facilities and modules related to LNG production. While we also typically engage an EPC contractor, such EPC contractors increasingly have a limited work scope, far less than for traditional facilities.

We constructed the Calcasieu Project pursuant to an EPC contract and have certified that it was performed in February 2023, subject to customary warranty obligations. In addition, we have entered into EPC contracts for both phases of the Plaquemines Project and for Phase 1 of the CP2 Project that require that the applicable contractor integrate such equipment and facilities and guarantee the full operation of the LNG export facilities. The services under the EPC contracts include contributing to the (i) design of balance of the plant and all interconnections including piping, utilities and associated infrastructure, (ii) procurement of all items not covered by our other construction and supply agreements, (iii) scheduling and coordination of the work and services performed by certain subcontractors and other contractors, (iv) site preparation, (v) installation and connection of all equipment supplied by our equipment suppliers, (vi) construction of the power plant forming part of the project, (vii) compliance with the contractor's warranty obligations and all applicable laws, codes and standards, and (viii) provision of project controls and construction performance indicators and invoice reconciliation.

Under each such contract that we have entered into for our projects, the EPC contractor has an uncapped make-good obligation to deliver a facility capable of passing certain performance tests. Each contractor is also required to pay us liquidated damages, subject to a specified cap and sub-limits for certain milestones, for any construction and/or performance testing delay. The aggregate amount of liquidated damages that would be payable under this arrangement with respect to each of these projects, in addition to the liquidated damages that would be payable under certain performance guarantees under the applicable liquefaction and power equipment purchase orders entered into pursuant to the Baker Hughes Master Agreement, are expected to be up to 10% of the aggregate construction cost for each project.

Further, under each such contract, the EPC contractor warrants that (i) it will perform the work under the EPC contract in full compliance with such contract, (ii) the materials and the work will be designed, manufactured, engineered, constructed, completed, pre-commissioned, commissioned, tested and delivered in a workmanlike manner and in accordance with each respective EPC contract, our standards, all permits and approvals of government authorities, applicable codes and standards and all applicable laws, (iii) the work will conform to the specifications and descriptions in its EPC contract, will be new, complete, and of suitable grade for the intended function and use, will be free from defects in design, material and workmanship, and will meet the requirements set forth in its EPC contract, (iv) the materials will be composed and made of only proven technology, of a type in commercial operation at the effective date of its EPC contract, (v) if a serial defect (two or more of the same components experience a defect of an identical or nearly identical nature) occurs as to its work done under the EPC contract prior to the expiration of each respective warranty period, it will redesign, repair or replace any materials as necessary and extend each respective warranty period for that portion of the work that is redesigned, repaired or replaced for an additional 12 months, and (vi) during the warranty period, it will perform tests, inspections or other diagnostic services requested by us and correct any non-conforming work discovered.

For Phase 2 of the CP2 Project and our other development projects, we aim to negotiate and enter into EPC contracts on similar terms as described above. However, as compared to the Calcasieu Project, the Plaquemines Project and Phase 1 of the CP2 Project, we aim to manage additional scopes of work directly. Specifically, we anticipate that we will perform additional construction oversight activities and deploy labor that we recruit to leverage lessons learned and the relationships fostered with construction and fabrication subcontractors while developing the Calcasieu Project and the Plaquemines Project, which we believe will help improve construction efficiency and reduce total costs for such projects.

Below is a summary of the Plaquemines EPC Contracts and the CP2 Phase 1 EPC Contract.

Plaquemines EPC Contracts

The Plaquemines EPC Contracts are separate contracts for Phase 1 and Phase 2 of the Plaquemines Project under which KZJV is the EPC contractor and which reflects the terms described above.

Under the Plaquemines EPC Contracts, KZJV will be paid a reimbursable sum for its scope of work, where we will reimburse KZJV for all reimbursable costs incurred in connection with the relevant work (such as costs for materials, transportation and equipment), plus a margin to cover overhead costs and expenses as well as an agreed profit margin. However, all other costs will not be reimbursed and will be borne by KZJV. The estimated reimbursable sum represents the "target price" for each phase of the Plaquemines Project, which is reflected in our estimated total cost for the Plaquemines Project. The target price is subject to adjustment under certain limited conditions, including pursuant to change orders we could submit with respect to the scope of work to be performed by KZJV or the project schedule.

The Plaquemines EPC Contracts establish an agreed project schedule for the applicable phase, including substantial completion deadlines and final completion deadlines, based on the achievement of the contractual conditions regarding the commissioning and completion of the LNG production systems that comprise Phases 1 and 2 of the Plaquemines Project, which may only be adjusted by change orders as provided in the Plaquemines EPC Contracts. Each of the project schedule milestones requires that the work performed meets or exceeds requirements under the Plaquemines EPC Contracts and certain material project schedule milestones additionally require that the work performed passes performance tests. KZJV has significant milestone and schedule-driven bonus incentives under the Plaquemines EPC Contracts that are intended to promote schedule adherence and a completion mindset. If KZJV fails to successfully pass the performance tests by the applicable deadlines for these milestones for reasons not caused by us or our other contractors, KZJV is obligated to perform all work necessary to successfully pass such tests at its own expense. Additionally, if KZJV exceeds the target price by certain agreed amounts, we could reduce KZJV's profit margin according to certain predetermined thresholds and if KZJV incurs delays in the project schedule beyond certain deadlines, KZJV could potentially owe us liquidated damages (subject to specified caps). Conversely, if KZJV's reimbursable costs are below the applicable target price or if KZJV completes certain work ahead of the applicable target schedule, (i) KZJV will be entitled to a share in certain benefits of cost savings and (ii) KZJV will receive incentive payments for early completion of certain milestones.

CP2 Phase 1 EPC Contract

Worley is the contractor under the CP2 Phase 1 EPC Contract. The CP2 Phase 1 EPC Contract is comparable in scope and terms to the Plaquemines EPC Contracts, with certain adjustments to account for the CP2 Project's schedule and minor configuration differences. The CP2 Phase 1 EPC Contract also includes substantial completion deadlines and final completion deadlines, with associated bonus incentives and exposure to liquidated damages depending on adherence to the project's schedule.

Like the Plaquemines EPC Contracts, under the CP2 Phase 1 EPC Contract, Worley will be paid a reimbursable sum for its scope of work under similar terms to those included in the Plaquemines EPC Contracts.

However, we anticipate that we will seek to manage additional scopes of work directly acting as EPCM, based on lessons learned and the relationships we have fostered with construction and fabrication subcontractors while developing the Calcasieu Project and the Plaquemines Project. The target price under the CP2 Phase 1 EPC Contract is subject to adjustment under certain limited conditions, including pursuant to change orders we could submit with respect to the scope of work to be performed by Worley or the project schedule.

Human Capital Resources

Our human capital is our most valuable asset, and we place a high premium on attracting, developing and retaining talented and high performing employees. As of December 31, 2024, we had over 1,500 full-time employees working on our engineering, project development, project financing, corporate finance, legal, and LNG marketing teams. As we develop and construct our projects, we expect to create additional highly skilled engineering, construction, manufacturing, and operating full-time and contractor jobs in Louisiana, Texas, and Virginia. We offer our employees a wide array of company-paid benefits and performance incentives, which we believe are competitive relative to others in our industry. Our employees are not represented by a labor union or covered by a collective bargaining agreement. We believe our relationship with our employees to be good.

Community Outreach

We aspire to set the standard for our industry in achieving positive impacts for our local communities and on a national level. In connection with the development of our projects, we provide substantial direct and indirect employment opportunities and have been a significant contributor to the domestic labor market with the jobs that we have created and supported. Taken together, we estimate that the Calcasieu Project and the Plaquemines Project have been supported by over 300 subcontractors across the country. At peak, we estimate that we have supported the employment of up to 9,000 construction jobs to construct the Calcasieu Project and the Plaquemines Project. We expect to directly hire approximately 800 permanent employees to operate and manage such projects and have already filled substantially all of these positions.

We strive to hire in-state and local workers where possible and, as of December 31, 2024, over 90% of the direct employees at the Calcasieu Project and the Plaquemines Project are from Louisiana. We anticipate that the CP2 Project will support the employment of over 7,500 on-site construction jobs at its peak and we expect to hire over 400 workers in permanent operational positions.

Further, we engage with the communities near our project sites by providing full-time employment and educational opportunities that allow local residents to develop new technical skills and succeed in related careers. We primarily pursue this through our "Will to Skill" program and our apprenticeship program. In 2020, we established our educational "Will to Skill" program in partnership with local colleges to provide technical training certifications to residents of the communities near our projects. As of December 31, 2024, over 350 individuals have graduated in the aggregate from the 30 cohorts of the Will to Skill program that we have offered in the various communities located near our project sites. Will to Skill participants graduate with occupational and industrial certifications that include construction, electrical, welding, maritime, and trucking skills. Additionally, in October 2023, we established a new apprenticeship program to provide a 12-month training program to local residents near Lake Charles, Louisiana. Upon the successful completion of the program, individuals are eligible to transition to full-time Venture Global employees as field operators and maintenance technicians.

Finally, we are a major financial supporter of the local communities in which we operate and have undertaken a multitude of community development and engagement activities. In particular, over the lifecycle of the Calcasieu Project, Plaquemines Project, and CP2 Project, we expect Venture Global will pay in excess of $7.0 billion in total parish property taxes.

Health and Safety

We are committed to providing a safe work environment across our businesses and strive towards best in class practices. We have built a dedicated Health, Safety, Security, and Environment, or HSSE, team that is accountable for the safe and responsible execution of our projects and reports to our Chief Operating Officer. At our project sites, our goal is to implement comprehensive safety programs that are appropriate for the hazards present at the various stages of construction and commissioning. This includes daily safety inspections, recurring safety trainings, and regular safety meetings. Our rigorous safety standards are continuously reviewed and updated to ensure they are fit for purpose within our workforce and we aim to meet the highest possible benchmarks. We believe that a strong safety culture leads to better safety performance, better operational performance, and higher staff morale. Our aggregate 0.18 TRIR which, when compared to the industry average for 2023 of 1.9 according to the Bureau of Labor safety statistics, is among the best in our industry and stands as testament to our commitments.

Governmental Regulation

Our operations are subject to extensive federal, state, and local regulation. Applicable laws require us to consult with applicable federal and state agencies, obtain and maintain applicable permits and authorizations, and comply with various ongoing regulatory requirements. This regulatory burden increases the cost of constructing and operating our projects, and failure to comply with such laws could result in substantial penalties and/or loss of necessary authorizations. See Item 1A.—*Risk Factors—Risk Relating to Regulation and Litigation—We may fail to receive the required approvals and permits from governmental and regulatory agencies for our projects* of this Form 10-K for more information.

Federal Energy Regulatory Commission (FERC)

The siting, construction, and operation of our natural gas liquefaction and export facilities are subject to FERC's approval and ongoing regulation, as is the construction and operation of our natural gas pipelines.

Pursuant to the Natural Gas Act, or the NGA, any person proposing to site, construct, or operate facilities (including LNG terminals) to be used for the export of natural gas from the United States to a foreign country must obtain authorization from FERC. FERC exercises comprehensive regulation of interstate natural gas pipelines, including requiring a certificate of public convenience and necessity to construct and operate such a pipeline, and requiring that the rates and terms of service for pipeline transportation service be just and reasonable under the NGA.

In addition to the initial FERC process for each of our projects summarized below, we note that throughout the life of each project, our LNG and pipeline facilities will be subject to ongoing FERC regulation and reporting requirements (as well as those of various other federal, state and local regulatory agencies). FERC's jurisdiction under the NGA and NGPA allows it to impose civil and criminal penalties for any violations of the NGA or NGPA, and any rules, regulations or orders of FERC up to approximately $1.58 million per day per violation, including any conduct that violates the NGA's prohibition against market manipulation.

Calcasieu Project

On February 21, 2019, FERC authorized the Calcasieu Project, as well as the construction and operation of the TransCameron Pipeline, subject to numerous conditions, or the Calcasieu FERC Order.

Construction and commissioning of the Calcasieu Project is subject to ongoing oversight by FERC and the Calcasieu FERC Order imposes ongoing conditions with which we must comply. On February 11, 2022, FERC authorized the export of our first LNG cargo, and we loaded our first commissioning cargo on March 1, 2022. Although we have completed most of the construction of the Calcasieu Project, the commissioning phase remains ongoing. On March 28, 2023, we submitted to FERC an update regarding commissioning and certain reliability challenges and needed repairs and replacements, and FERC authorized our remediation plans on October 12, 2023.

With the requisite authorization, the TransCameron Pipeline was placed in service by FERC in April 2021.

On September 22, 2023, FERC approved an amendment to our FERC authorizations for the Calcasieu Project to increase the permitted capacity under optimal conditions from 12.0 to 12.4 mtpa, subject to certain conditions.

On February 15, 2024, we submitted to FERC a request for a one-year extension of time, if deemed necessary, to the in-service condition in the Calcasieu FERC Order. The extension request remains pending at FERC.

Plaquemines Project

On September 30, 2019, FERC authorized the Plaquemines Project, as well as the construction and operation of the Gator Express Pipeline, subject to numerous conditions, or the Plaquemines FERC Order. Construction of the Plaquemines Project is subject to ongoing oversight by FERC and the Plaquemines FERC Order imposes ongoing conditions with which we must comply.

With the requisite authorization, the two Gator Express lateral pipelines were placed in service by FERC in May 2024 and December 2024.

On March 11, 2022, we submitted an application with FERC to amend the terms of our FERC authorization to increase the authorized permitted production capacity under optimal conditions from 24.0 to 27.2 mtpa. This "uprate" in the regulatorily authorized production capacity is based on updated engineering and vendor data, and does not involve the construction of any new facilities nor any modification of the previously authorized facilities. FERC issued an order approving this uprate amendment application on February 19, 2025.

On March 6, 2025, we made a formal request to FERC to initiate the Commission's National Environmental Policy Act, or NEPA, pre-filing review process for bolt-on expansion capacity at our current Plaquemines Project, or the Plaquemines Expansion Project. Subject to regulatory approval, among other things, and our ability to secure additional natural gas, pipelines and pipeline transportation capacity, we anticipate that the Plaquemines Expansion Project will involve the construction and operation of new liquefaction facilities capable of producing incremental peak capacity of 18.6 mtpa on a 600-acre site controlled by one of our subsidiaries and located immediately adjacent to the current Plaquemines Project. We aim to file a formal application for the Plaquemines Expansion Project with FERC in the second half of 2025.

CP2 Project

On June 27, 2024, FERC authorized the CP2 Project, as well as the construction and operation of the CP Express Pipeline, subject to numerous conditions, or the CP2 Project FERC Order. In July 2024, a group of opponents composed mostly of environmental groups filed a request for rehearing of the FERC authorization, raising a number of challenges to the FERC authorization. In a notice issued in August 2024, FERC denied rehearing by operation of law while providing for further consideration. Project opponents consisting of numerous environmentalist organizations and certain individuals filed petitions for review of FERC's authorization order with the US Court of Appeals for the D.C. Circuit on September 4, 2024. FERC denied a motion for stay of its authorization order on October 1, 2024. The D.C. Circuit denied a similar request for stay filed by project opponents on November 8, 2024, and established a briefing schedule through April 2025.

On November 27, 2024, FERC issued an order on rehearing that generally rejected the arguments opposing the CP2 Project and noted that it remains confident in the authorization order, but decided to partially "set aside" its prior analysis of the cumulative air impacts of emissions of nitrogen dioxide (NO_2) and particulate matter less than 2.5 micrometers ($PM_{2.5}$) and to prepare a supplemental Environmental Impact Statement concerning that topic and to address it along with certain other air quality issues in a future order. FERC also announced that, due to its initiation of supplemental environmental review, it will not issue authorizations to proceed with construction until the Commission issues a further merits order. In response to FERC's order on rehearing, the D.C. Circuit on December 13, 2024, granted an unopposed motion by FERC to hold the appeal in abeyance. On February 7, 2025, FERC issued a draft supplemental Environmental Impact Statement, concluding that the project will have no significant cumulative air quality impacts and that all its previous environmental conclusions remain unchanged. Public comments on the draft Environmental Impact Statement are due by March 31, 2025, and FERC's schedule provides for the final Environmental Impact Statement to be issued by May 9, 2025.

In addition to the supplemental environmental review and the appeal, construction of the CP2 Project will be subject to ongoing oversight by FERC in accordance with the terms and conditions of the CP2 Project FERC Order. While we have already begun to submit implementation plans for this purpose, FERC has not yet authorized any on-site construction as of the date of this Form 10-K.

CP3 Project and Delta Project

We have not yet submitted a formal FERC application for the CP3 Project or the Delta Project. Such approvals are subject to a number of risks, and there can be no assurances as to when we will file the formal applications or when we will receive the approvals, if at all.

DOE Export Authorizations

Section 3 of the NGA requires any person seeking to import natural gas from, or export natural gas to, a foreign country to obtain authorization from the DOE. The DOE's Office of Fossil Energy and Carbon Management, or DOE/FECM, reviews applications to import or export natural gas.

The NGA sets forth separate standards of review for exports to (1) countries with which the United States has a free trade agreement requiring national treatment for trade in natural gas, or FTA Nations, and (2) countries with which there is no such free trade agreement in effect, or Non-FTA Nations. Applications seeking authorization to export LNG to FTA Nations are deemed consistent with the public interest and must be granted without modification or delay. FTA Nations currently include Australia, Bahrain, Canada, Chile, Colombia, Dominican Republic, El Salvador, Guatemala, Honduras, Jordan, Mexico, Morocco, Nicaragua, Oman, Panama, Peru, Republic of Korea, and Singapore. In contrast, Non-FTA Nations export applications are subject to a public interest review. DOE/FECM will grant the requested authorization unless it finds, after providing for a public comment period, that the proposed exports will be inconsistent with the public interest, and may approve an application in whole or in part, and with such modifications and upon such terms and conditions as it deems necessary or appropriate. DOE/FECM's established practice is to act on long-term authorizations to export to Non-FTA Nations only after the FERC has authorized the siting, construction and operation of the associated LNG facilities.

In January 2024, the Biden administration announced a temporary pause on new authorizations of natural gas exports to Non-FTA Nations while the DOE conducts studies to update its analyses regarding whether the exports are "not inconsistent with the public interest" to consider the latest available information regarding macro-economic impacts, domestic energy prices, potential greenhouse gas, or GHG, or climate or other environmental effects, and national security implications. On July 1, 2024, a federal court in Louisiana granted a motion for preliminary injunction filed by numerous states, holding the DOE pause appears to be unlawful and staying the pause in its entirety.

On December 17, 2024, DOE publicly released a multi-volume study of its views of the potential effects of U.S. LNG exports on the domestic economy; U.S. households and consumers; communities that live near locations where natural gas is produced or exported; domestic and international energy security, including effects of U.S. trading partners; and the environment and climate. DOE stated that it intends to use this study to inform its public interest review of and future decisions regarding exports to Non-FTA Nations. The study was initially subject to a public comment period scheduled to expire on February 18, 2025.

On January 20, 2025, the Trump administration issued an Executive Order entitled "Unleashing American Energy," that, among other provisions, directed DOE to restart reviews of applications for approvals of LNG exports and directed the consideration of the economic and employment impacts to the U.S. and the impact to the security of allies and partners that would result from granting the application. Other parts of the wide-ranging Executive Order require expedited permitting and elimination of delays and revoke prior executive orders related to the CEQ and GHG emissions. A second Executive Order issued that same day declared a "National Energy Emergency" and, among other things, recognized the benefits of selling LNG to international allies and partners. On January 21, 2025, DOE directed the Office of Fossil Energy and Carbon Management to resume consideration of pending applications for LNG exports in accordance with the NGA and extended the comment period on the DOE study to March 20, 2025 "to ensure such public interest determinations receive appropriate stakeholder input." The first Secretarial Order issued by new DOE Secretary Wright on February 5, 2025, stated that DOE has resumed consideration of pending export authorizations and will identify and exercise its legal authorities to expedite the approval and construction of reliable energy infrastructure. On February 14, 2025, DOE Secretary Wright announced the issuance of a conditional authorization to export LNG to Non-FTA Nations to Commonwealth LNG. Nevertheless, there can be no assurance as to DOE's further implementation of the Executive Orders, the Trump administration's views of the recently released DOE study or its future policies, or the impact of those policies on our existing and future projects, including the applications described below, or on any contracts related to our existing and future projects. For more information on these risks, see Item 1A.—*Risk Factors—Risks Relating to Regulation and Litigation—We may fail to receive the required approvals and permits from governmental and regulatory agencies for our projects* of this Form 10-K.

Calcasieu Project

DOE/FECM approved our applications for exports from the Calcasieu Project to FTA Nations in May 2013 for 5 mtpa, in May 2014 for an additional 5 mtpa, and in February 2015 for an additional 2 mtpa, for a total volume of 620 Bcf/yr of natural gas (equivalent to 12 mtpa), and originally for a term of 25 years beginning the earlier of (i) the date of first export or (ii) seven or eight years (depending on the specific terms of each authorization) from the date of the authorization. DOE/FECM granted us long-term authorization for export to Non-FTA Nations on March 5, 2019. The non-FTA export authorization also is for up to 620 Bcf/yr of natural gas (equivalent to 12 mtpa), for an original term of 20 years from the date of first export, while providing that exports must commence no later than seven years from the date of the authorization. The authorized volumes to FTA Nations and Non-FTA Nations are not cumulative.

On October 21, 2020, DOE/FECM granted our request to extend the term in all the Calcasieu Project's long-term export authorizations, extending the term in each Calcasieu Project export authorization through December 31, 2050 (inclusive of any make-up period).

On December 18, 2020, DOE/FECM issued a blanket order, Order No. 4641, amending certain existing export authorizations, and amended the existing long-term authorizations for the Calcasieu Project to include short-term export authority, including to export commissioning volumes.

In December 2021, we submitted an application with DOE/FECM to amend the terms of our FTA and non-FTA export authorizations for the Calcasieu Project to increase the authorized export capacity from 12.0 to 12.4 mtpa. DOE authorized the increased level of export to FTA Nations on April 22, 2022, but has not yet acted on the request to increase the authorized level of exports to Non-FTA Nations.

Plaquemines Project

DOE/FECM approved on July 21, 2016, our application for exports from the Plaquemines Project to FTA Nations for 1,240 Bcf/yr of natural gas (equivalent to 24 mtpa), and originally for a term of 25 years beginning the earlier of (i) the date of first export or (ii) seven years from the date of the authorization. DOE/FECM granted us long-term authorization for export of the same 1,240 Bcf/yr of natural gas (equivalent to 24 mtpa) from the Plaquemines Project to Non-FTA Nations on October 16, 2019 for an original term of 20 years from the date of first export, while providing that exports must commence no later than seven years from the date of the authorization. The authorized volumes to FTA Nations and Non-FTA Nations are not cumulative.

On October 21, 2020, DOE/FECM granted our request to extend the term of the Plaquemines Project's long-term export authorizations, extending the term in each Plaquemines Project export authorization through December 31, 2050 (inclusive of any make-up period).

Just as for the Calcasieu Project, the blanket order described above also amended the existing long-term authorizations for the Plaquemines Project to include short-term export authority, including to export commissioning volumes.

On March 11, 2022, we submitted an application with DOE/FECM to amend the terms of our FTA and non-FTA export authorizations for the Plaquemines Project to increase the authorized export capacity under optimal conditions from 24.0 to 27.2 mtpa. DOE authorized the increased level of export to FTA Nations on June 13, 2022, but has not yet acted on the request to increase the authorized level of exports to Non-FTA Nations, which is consistent with DOE practice of waiting to take action on the Non-FTA portion of an application until after FERC has approved the corresponding project, which occurred on February 19, 2025.

CP2 Project

DOE/FECM approved on April 22, 2022, our application for exports from the CP2 Project to FTA Nations for a 1,446 Bcf/yr of natural gas (equivalent to 28 mtpa), for a term extending through 2050. Our request for authorization for exports from the CP2 Project to Non-FTA Nations remains pending before DOE/FECM. DOE issued a statement on December 10, 2024, stating that it cannot complete its review of non-FTA export authorizations for projects still undergoing environmental review before other federal agencies, specifically mentioning (among other projects) the FERC order on rehearing for the CP2 Project requiring supplemental environmental review.

CP3 Project and Delta Project

We have not yet filed any application with DOE/FECM for the authorization of natural gas exports from the CP3 Project or the Delta Project. We anticipate submitting the export authorization application for the CP3 Project and the Delta Project at approximately the same time as our formal FERC applications for each project.

Department of Transportation Pipeline and Hazardous Materials Safety Administration

Our projects must comply with certain safety standards set by PHMSA. 49 C.F.R. Part 193, *Federal Safety Standards for Liquefied Natural Gas Facilities*, which establishes minimum federal safety standards for the siting, construction, operation, and maintenance of onshore LNG facilities and the siting of marine cargo transfer systems at waterfront LNG plants. These standards also incorporate by reference the National Fire Protection Association, Standard 59A, "Standard for the Production, Storage, and Handling of Liquefied Natural Gas." PHMSA issued a Letter of Determination, or LOD, regarding compliance with the applicable standards for each of the Calcasieu Project (including its "uprate" amendment) and the Plaquemines Project as part of the FERC process, before each project was authorized by FERC. PHMSA has also issued its LOD for the CP2 Project, as well as for the Plaquemines Project "uprate." Once constructed and operational, each of our LNG facilities' compliance with 49 C.F.R. Part 193 will be subject to DOT's inspection and enforcement program.

Other Governmental Permits, Approvals and Authorizations

The construction and operation of our projects is subject to additional federal and state permits, orders, approvals, and consultations required by other federal and state agencies, including the DOE, U.S. Army Corps of Engineers, U.S. Department of Commerce, National Oceanic and Atmospheric Administration, National Marine Fisheries Services, Federal Aviation Administration, U.S. Fish and Wildlife Service, EPA, Louisiana Department of Environmental Quality, Louisiana Department of Energy and Natural Resources, and U.S. Department of Homeland Security. We currently have all material permits required for the Calcasieu Project's and the Plaquemines Project's respective current stage of construction and operations. Permitting for the CP2 Project remains ongoing, while permitting for the potential bolt-on expansion for the Plaquemines Project, the CP3 Project and the Delta Project is at an earlier stage.

Commodity Futures Trading Commission (CFTC)

We have entered into interest rate hedges, including interest rate swaps, in connection with the Plaquemines Credit Facilities and the Calcasieu Pass Credit Facilities, and we may enter into additional interest rate hedges and other derivatives in the future. Pursuant to authority granted by the CEA, the CFTC exercises federal oversight and regulation of the derivatives market in the United States for most types of derivatives and entities, like us, that participate in that market.

Among other CFTC requirements, the CFTC's swaps rules impose a range of regulatory requirements on parties transacting in swaps that, among other things: (i) provide for the registration and regulation of Swap Dealers and Major Swap Participants; (ii) impose clearing and trade execution requirements for certain swaps, subject to certain exceptions; (iii) establish swaps recordkeeping and reporting regimes; and (iv) implement the CFTC's anti-manipulation, anti-fraud, and anti-disruptive trade practice authority.

As a commercial end-user, we are subject to only limited CFTC swaps requirements. However, the application of these requirements to other market participants may affect the overall swaps market, including the costs and availability of the types of swaps we use to hedge or mitigate our commercial risks. In addition, the CFTC's swap requirements remain subject to changes from future rule amendments, interpretive guidance and no-action relief, and the ultimate effect on our business of any changes to the rules or interpretive guidance, or of any new rules in the future, remains uncertain.

Environmental Regulation

Our projects are subject to various federal, state, and local environmental statutes and regulations intended to ensure the protection of the environment. In certain cases, these environmental laws and regulations require us to obtain permits and authorizations and engage in agency consultations prior to construction and operation of a project. Many laws and regulations restrict or prohibit the types, quantities, and concentration of substances that can be released into the environment. In addition, our LNG tankers are subject to environmental regulations, rules and conventions adopted in the jurisdictions in which they call or are flagged, including requirements to record and report their fuel consumption. Similarly, our downstream sales of LNG into, for example, the European Union, are subject to environmental-based monitoring and reporting adopted in those jurisdictions. Failure to comply with these laws and regulations may result in substantial civil and criminal fines and penalties. See Item 1A.—*Risk Factors*—*Risks Relating to Regulation and Litigation—Existing and future environmental and similar laws and governmental regulations could result in increased compliance costs or additional operating and/or construction costs and restrictions* of this Form 10-K for more information.

Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)

Certain aspects of our projects may be subject to the Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, which provides for the investigation, cleanup, and restoration of natural resources from releases of hazardous substances (not including "petroleum"). We may be subject to liability under CERCLA as a result of contamination at properties currently or formerly owned, leased, or operated by us or our predecessors or at third-party contaminated facilities to which we have sent waste for treatment or disposal. Liability under CERCLA can be imposed on a joint and several basis and without regard to fault or the legality of the conduct giving rise to contamination.

Clean Air Act (CAA)

Our projects are subject to the CAA and comparable state and local laws. Under the CAA, the EPA has the authority to control air pollution by issuing and enforcing regulations for entities that emit substances into the air. The EPA has promulgated regulations for major sources of air pollution and has delegated implementation of these regulations to state agencies, including the Louisiana Department of Environmental Quality and the Texas Commission on Environmental Quality. In addition to having obtained relevant air permits from the Louisiana Department of Environmental Quality prior to construction of the Calcasieu Project and the Plaquemines Project, we are subject to ongoing emissions standards, requirements, and reporting obligations under the EPA rules, as well as under Louisiana, and in the case of the CP2 Project, Texas state regulatory agencies.

Coastal Zone Management Act (CZMA)

The Coastal Zone Management Act, or CZMA, is intended to ensure the effective management, beneficial use, protection, and development of the nation's coastal zone. Under the CZMA, participating states are required to develop management programs demonstrating how they will meet their obligations and responsibilities in managing their coastal areas. The Louisiana Department of Natural Resources, which administers the CZMA for each of our projects, issued a coastal use permit and related mitigation plan for the Calcasieu Project and an exemption for the LNG terminal and a "no direct or significant impact" (NDSI) exemption for the marine facility for the Plaquemines Project. The CP2 Project received its CZMA authorization in March 2024.

Clean Water Act (CWA) and Rivers and Harbors Act

Our projects are subject to the CWA, which regulates discharges of pollutants into the waters of the United States, as well as analogous state and local laws. Under section 401 of the CWA, a federal agency may not issue a permit for any activity that may result in any discharge into the waters of the United States unless the state where the discharge would originate either issues a water quality certification verifying compliance with existing water quality requirements or waives the certification requirement or waives this requirement. Additionally, section 404 of the CWA regulates the discharge of dredged or fill material into waters of the United States, including wetlands. Each of the Calcasieu Project, Plaquemines Project, and CP2 Project has received a water quality certification from the Louisiana Department of Environmental Quality, Water Quality Division. The Calcasieu Project and the Plaquemines Project have received CWA section 404 permits and section 10 of the Rivers and Harbors Act from the U.S. Army Corps of Engineers, or USACE, and permits from the Louisiana Department of Environmental Quality for the discharge of stormwater arising in connection with construction activities and industrial operations once construction is complete, and the discharge of wastewater generated during the operation of the facility.

Resource Conservation and Recovery Act (RCRA)

Under the Resource Conservation and Recovery Act, or RCRA, and comparable state hazardous waste laws, the EPA and authorized state agencies, including the Louisiana Department of Environmental Quality and the Texas Commission on Environmental Quality, regulate the generation, transportation, treatment, storage, and disposal of hazardous waste. If hazardous wastes are generated or stored in connection with any of our projects, we would be subject to the requirements of such laws.

Endangered Species Act, or ESA, Magnuson-Stevens Fishery Conservation and Management Act, or MSFCMA, and National Environmental Policy Act, or NEPA

Section 7 of the Endangered Species Act provides that any project authorized by any federal agency should not jeopardize the continued existence of any endangered species or threatened species, or result in the destruction or adverse modification of habitat of such species which is determined to be critical. The Magnuson-Stevens Fishery Conservation and Management Act, or MSFCMA, establishes procedures designed to identify, conserve, and enhance essential fish habitat for those species regulated under a federal fisheries management plan. During the FERC review process for each of our Projects, we engaged in consultation with the relevant federal agencies pursuant to the ESA and MSFCMA. Such consultation was completed for the Calcasieu Project, the Plaquemines Project, and the CP2 Project, but has not yet begun for the CP3 Project or the Delta Project or any potential bolt-on expansions.

The issuance of requisite permits and authorizations for our projects may be subject to environmental review under the National Environmental Protection Act, or NEPA. NEPA requires federal agencies to evaluate the environmental impact of major agency actions that may significantly affect the quality of the human environment, such as the granting of a permit or similar authorization for the development of certain projects. As part of NEPA review, federal agencies will prepare an environmental assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. In May 2024, the Council on Environmental Quality, or CEQ, published its final "Phase 2" NEPA regulations, which include specific direction to account for both climate change and environmental justice effects in NEPA reviews. However, the status of these rules, as well as the NEPA review process in general, is subject to significant uncertainty. In November 2024, the majority opinion in a ruling by a panel of the U.S. Court of Appeals for the D.C. Circuit stated that the CEQ lacks authority to issue NEPA regulations. Although a subsequent majority en banc opinion by the D.C. Circuit clarified that this statement is not binding precedent, in February 2025, the District Court for North Dakota held that the CEQ lacks authority to issue NEPA regulations and vacated the CEQ's 2024 "Phase 2" rule. In addition, executive action taken by President Trump on his first day in office with respect to energy policy and climate change, among other things, directs CEQ to propose rescinding existing NEPA regulations and issue guidance and coordinate agency level regulations implementing NEPA that expedites permitting and prioritizes energy production. On February 25, 2025, CEQ published an interim final rule, "Removal of National Environmental Policy Act Implementing Regulations," in the Federal Register which, effective April 11, 2025, that will rescind CEQ's existing NEPA regulations in their entirety, subject to CEQ's consideration of public comments submitted by the effective date. The impact of these legal developments cannot be fully predicted at this time. The NEPA review process can lead to significant delays in approval of such projects and the issuance of the requisite permits. As a result of its NEPA review, a federal agency may decide to deny permits or other support for a project, or condition approvals on certain modifications or mitigation actions.

Seasonality

Seasonal weather can affect the need for our LNG sales. While we expect that a substantial amount of our LNG will be sold under long-term, post-COD SPAs, due to the commissioning activities at the Calcasieu Project and the Plaquemines Project, including the marketing, loading, and shipping of our cargos of LNG, we have already begun experiencing, and we expect to experience for our other projects as we begin commissioning activities for such projects, the effects of market volatility and fluctuation in seasonal demand for LNG in our existing markets. Additionally, excess LNG produced by our projects above the nameplate capacity that is sold to VG Commodities or otherwise can, to the extent not previously committed to third parties, be resold to third party customers at our discretion under short-, medium-, or long-term contracts, including on a forward spot basis, which would expose our revenues to such volatility and fluctuation in seasonal demand. Changes in temperature and weather may affect both power demand and power generation mix in the locations we service, including the portion of electricity provided through other sources of energy, such as hydroelectric, solar, or wind, thus affecting the need for regasified LNG. These changes can increase or decrease demand for LNG and accordingly, fluctuations in revenue during quarters of high and low demand, respectively, could have a disproportionate effect on our results of operations, especially with regard to the LNG sold into the spot market.

Competition

The global LNG and natural gas markets are highly competitive. We compete with many participants across an integrated supply chain, including independent LNG producers, commodities marketing and trading firms, national energy companies, utility companies, and major multinational energy companies, primarily over supplies of natural gas and sales of our LNG. We believe our proprietary mid-scale, factory-built liquefaction train design, project execution excellence, access to well-priced and abundant, domestically sourced natural gas, simultaneous construction and integrated operations approach, with its associated commissioning cargos and proceeds, capital strength, leadership, and mission and values-led culture position Venture Global well to compete and thrive against this diverse competitive landscape.

We are subject to market-based price competition, reflecting supply and demand market pricing dynamics, with respect to revenue associated with any sales of our commissioning cargos and sales of LNG in excess of our nameplate capacity. Due to the commissioning activities at the Calcasieu Project, including the marketing, loading and shipping of our cargos of LNG, we have already begun experiencing competition with respect to LNG sales, including the effects of changes in supply and demand due to recent market volatility. The balance between the availability of LNG and the market demand for LNG significantly affects competition and the market price for our products. This dynamic is particularly acute for cargos sold on a forward spot or short-term contracted basis, such as any commissioning and excess capacity cargos. Even after COD for our projects, we may continue to have a meaningful component of our production and sales subject to spot and short- or intermediate-term market dynamics. This may occur as a result of marketing excess capacity cargos through VG Commodities under excess capacity SPAs to the extent these cargos are not previously contracted, or as a result of marketing any portion of the nameplate capacity of our projects that is not contracted under post-COD SPAs at any time.

Our current development projects, any future projects we develop, and any expansions of our projects will compete with other domestic and international suppliers on the basis of price per contracted volume of LNG with other LNG projects throughout the world, including other LNG projects being developed by us and other LNG projects in operation and under development.

With respect to our projects, our current and potential competitors include, but are not limited to, (1) national energy companies, such as QatarEnergy, (2) major multinational energy companies, including BP, Chevron, ConocoPhillips, ExxonMobil, Shell and Total, (3) independent LNG producers, including Cheniere and Freeport LNG, (4) utility companies, such as Sempra, and (5) commodities marketing and trading firms, such as Glencore, Trafigura, and Vitol. Some of our competitors may have financial, engineering, marketing, and other resources greater than we have, and some of them are fully integrated energy companies. Importantly, many of our competitors are also our customers with whom we have short-, intermediate-, and long-term contractual relationships.

Insurance

We maintain a comprehensive insurance program to insure potential losses to Venture Global, the Calcasieu Project, and the Plaquemines Project from physical loss or damage, including due to floods and named windstorms, as well as third-party liabilities, during construction and subsequent operation. We expect to establish a similar comprehensive insurance program for the CP2 Project, with initial environmental, third party liability, and cargo policies in place, and our current development projects at the appropriate and prudent time. In addition, we expect to establish a comprehensive insurance program to insure against customary risks and losses for our LNG tankers and regasification terminal assets at the appropriate and prudent time and have already placed protection and indemnity coverage and hull and machinery insurance for our two, newbuild LNG tankers that were delivered in July 2024 and placed charterers' liability insurance for our four chartered LNG tankers that were delivered in the second half of 2024. We may not be able to maintain adequate insurance in the future at rates that are considered reasonable. See Item 1A.—*Risk Factors*—*Risks Relating to Our Business—We are unable to insure against all potential risks and may become subject to higher than expected insurance premiums. In addition, we retain certain risks as a result of insurance through our captive insurance* of this Form 10-K.

Available Information

Our Class A common stock has been publicly traded since January 24, 2025 and is traded on the New York Stock Exchange under the symbol "VG." Our principal executive offices are located at 1001 19th Street North, Suite 1500, Arlington, VA, 22209, and our telephone number is (202) 759-6740. Our internet address is www.ventureglobal.com. We provide public access to our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to these reports as soon as reasonably practicable after we electronically file those materials with, or furnish those materials to, the SEC under the Exchange Act. These reports may be accessed free of charge through our internet website. We make our website content available for informational purposes only. The website should not be relied upon for investment purposes and is not incorporated by reference into this Form 10-K.

We will also make available to any stockholder, without charge, copies of our annual report on Form 10-K as filed with the SEC. For copies of this, or any other filing, please contact: Venture Global, Inc., Investor Relations, 1001 19th Street North, Suite 1500, Arlington, VA, 22209 or call (202) 759-6740. The SEC maintains an internet site (www.sec.gov) that contains reports, proxy and information statements, and other information regarding issuers.

ITEM 1A. RISK FACTORS

You should carefully consider the risks and uncertainties described below, together with all other information contained in this Form 10-K, including those discussed in Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations* of this Form 10-K. If any of the following risks were to occur, our business, financial condition, results of operations and cash flow could be materially adversely affected. The following risks are not the only ones facing our company. Additional risks and uncertainties not currently known to us, or that we currently deem immaterial, may also impair or adversely affect us.

Risks Relating to Our Business

Our ability to maintain profitability and positive operating cash flows is subject to significant uncertainty.

We will continue to incur significant capital and operating expenditures while we develop, construct, and commission our projects. Our ability to maintain profitability and positive operating cash flows is primarily dependent on our ability to generate proceeds, and in turn net profits and operating cash flows, through the sale of LNG commissioning cargos, the sale of excess LNG that is produced above the nameplate capacity of our LNG projects, and, after COD occurs for a given project, through the sale of LNG pursuant to our post-COD SPAs, as well as our ability to monetize our other assets (such as pipelines, LNG tankers and downstream regasification capacity).

Our ability to sell LNG commissioning cargos depends on our ability to successfully market, produce, load and, in some cases, deliver commissioning cargos during the commissioning of each of our projects prior to achieving COD. Although we have generated proceeds from the sales of commissioning cargos at the Calcasieu Project since the first quarter of 2022 and at the Plaquemines Project since January 2025, prior to the relevant COD, such sales of commissioning cargos are limited in duration and subject to a number of material uncertainties and risks. In addition, we are obligated to cease sales of commissioning cargos once the relevant COD occurs. The duration of the commissioning period at the Calcasieu Project, which has been extended by a *force majeure* event, and the amount of proceeds we have generated from the sales of commissioning cargos from the Calcasieu Project to date may not be indicative of the duration of the commissioning period or the amount of proceeds from such sales for any future period for the Calcasieu Project or for any of our other projects, including bolt-on expansions thereof. See *—Our ability to generate proceeds from sales of commissioning cargos is subject to significant uncertainty and volatility in such proceeds, given significant volatility in spot-market prices* and *—Historical proceeds from commissioning cargo sales at the Calcasieu Project, which has had an extended commissioning period due to unanticipated challenges with equipment reliability that we are in the process of remediating and which began producing LNG in a high-price environment, may not be indicative of the duration of the commissioning period or the amount of proceeds for any future period or for any of our other projects, including bolt-on expansions thereof.*

Our ability to generate sales of LNG following COD at each of our projects depends on our ability to successfully commence and maintain deliveries under our post-COD SPAs. Such revenues can be further supplemented if we are able to produce and sell LNG in excess of the nameplate capacity of our projects. We will not generate any revenues or operating cash flow under our post-COD SPAs, or from sales to third parties of excess LNG until we have achieved COD for the relevant project. There is no guarantee that we will achieve such CODs within the anticipated timeframes for achieving COD at any of our projects or at all, including as a result of risks described elsewhere in these "Risk Factors", including *—Risks Relating to Regulation and Litigation—We may fail to receive the required approvals and permits from governmental and regulatory agencies for our projects.*

As a result, there can be no assurance as to when we will commence deliveries under our post-COD SPAs, and therefore when, if at all, we will commence generating revenues and operating cash flows from our post-COD SPAs or from the sale of LNG produced in excess of nameplate capacity, if any, for the Calcasieu Project or any of our other projects, including bolt-on expansions thereof. In addition, there can be no assurance that we will be able to produce excess LNG above the nameplate capacity of the facilities at our projects, either at our target level of excess LNG production or at all, nor, even if such excess LNG is produced, that we will be able to resell all of it to third party customers.

Our ability to monetize our other assets, including our pipelines, LNG tankers and regasification facility capacity depends on a variety of factors, including but not limited to market conditions in the natural gas and LNG industries, required regulatory and governmental approvals, and our ability to successfully market, produce, load and deliver commissioning cargos during the commissioning of each of our projects prior to achieving COD and our ability to generate sales of LNG following COD at each of our projects. Specifically, our ability to construct and successfully monetize our interstate and intrastate pipelines will depend, among other factors, on worldwide demand for LNG, as well as on our obtaining the necessary regulatory approvals for our projects currently under development. Additionally, while we expect several of our LNG tankers to service our single DPU post-COD SPA, our ability to monetize the remainder of our LNG tanker fleet will depend on the demand from LNG customers or, potentially, other charterers, as well as that from any future SPAs we may enter into where LNG is sold on a delivered basis, for the services of such LNG tankers. Our ability to monetize the regasification facility capacity we have secured through our agreements with Grain LNG and the Alexandroupolis LNG receiving terminals will depend on demand for both LNG and regasified natural gas from downstream customers in the UK and European markets.

As a result, there is significant uncertainty about our ability to maintain profitability and positive operating cash flows.

We have only a limited track record and historical financial information, and there is no assurance that our business will be successful over the long term.

We first generated proceeds from sales of commissioning cargos at the Calcasieu Project only in the first quarter of 2022, and prior to that we incurred significant losses from operations and negative cash flows from operations.

Our activities to date have included organizational efforts related to the development and construction of our projects and related assets, including but not limited to:

- raising capital;
- securing options to lease and leasing our project sites;
- negotiating and planning with various contractors for the development and production of such sites;
- negotiating SPAs with purchasers;
- negotiating and entering into construction contracts with construction contractors; and
- procuring gas transportation and supply.

In addition, as of December 31, 2024, substantially all of the proceeds we have generated were proceeds generated from sales of commissioning cargos from the Calcasieu Project, and may not be indicative of the duration of the commissioning period or the amount of proceeds from such sales for any future period for the Calcasieu Project or for any of our other projects, including bolt-on expansions thereof, or of our future results of operations more generally.

Our limited operating history may limit your ability to evaluate our prospects because of our limited historical financial data, our unproven ability to maintain or increase our profitability and our limited experience in addressing issues that may affect our ability to manage the construction, operation or maintenance of liquefaction facilities and related assets. We face all of the risks commonly encountered by other growing businesses, including competition and the need for additional capital and personnel. As a result, any assessment you make about our current business and any predictions you make about our future success or viability may not be accurate. There is no assurance that our business will be successful over the long term.

Historical proceeds from commissioning cargo sales at the Calcasieu Project, which has had an extended commissioning period due to unanticipated challenges with equipment reliability that we are in the process of

remediating and which began producing LNG in a high-price environment, may not be indicative of the duration of the commissioning period or the amount of proceeds for any future period or for any of our other projects, including bolt-on expansions thereof.

The duration of the commissioning period and our ability to generate proceeds from the sale of commissioning cargos during such period is subject to significant risks and uncertainties relating to the development, construction and commissioning of our projects as discussed in these "Risk Factors." In particular, it is both our intention and our obligation, under our post-COD SPAs, to undertake the construction of and complete our projects or phases thereof in a reasonable and prudent manner, which, depending on the circumstances, could extend or shorten the commissioning period for such projects or phases thereof during which we are able to generate such proceeds. Further, certain delays in the development of or construction of our projects, and any issues with the construction of our projects could delay or otherwise adversely impact our ability to generate such proceeds during the commissioning of the relevant projects. At any of our projects or phases thereof, if the commissioning of certain equipment or integrated facilities is delayed or if COD occurs earlier than expected, the duration of time when we are able to generate proceeds from the sale of commissioning cargos may be shortened, which could adversely impact the volume of LNG produced during commissioning and our ability to generate proceeds from the sale of commissioning cargos.

Historical proceeds from the sale of commissioning cargos at the Calcasieu Project, which has had an extended commissioning period due to unanticipated challenges with equipment reliability that we are in the process of remediating, may not be indicative of the duration of the commissioning period or the amount of proceeds for any future period or for any of our other projects, including bolt-on expansions thereof. Although we have included targeted COD dates for certain of our projects and phases thereof, there can be no assurance that COD will not occur earlier or later than such targets. If COD occurs earlier than expected for a particular project or phase thereof, it would adversely impact our ability to generate proceeds from the sale of commissioning cargos, which, subject to market conditions, may otherwise be more valuable than the revenues earned under our post-COD SPAs.

Our ability to generate proceeds from sales of commissioning cargos is subject to significant uncertainty and volatility in such proceeds, given significant volatility in spot-market prices.

A key element of our business strategy is to generate proceeds from the sale of LNG at each of our projects during the construction and commissioning phases of our projects, prior to the relevant project achieving COD.

In addition to the duration of the commissioning period, our ability to generate such proceeds depends on our ability to negotiate sales during the construction and commissioning phases of each project. There is no assurance that we will be able to continue to successfully negotiate sales of such commissioning cargos on terms that are acceptable to us, or that we will be able to successfully market, produce, load and deliver such commissioning cargos, either from the Calcasieu Project or any other project, in the future. In addition, because commissioning cargos are not sold under post-COD SPAs and are instead sold on varying terms, including in some instances on a forward basis, proceeds from such commissioning cargos may vary significantly depending on, among other factors, prices and market conditions in the international LNG markets, global LNG freight rates, and on the timing of when a contract for sale is executed. As such, the amount of any proceeds that we may generate from the sale of commissioning cargos and our profitability relating to such sales is largely dependent on the strength of international LNG markets, as primarily reflected in the spot price for LNG at the time a contract for sale of commissioning cargos is executed. Historically, the spot price for LNG has varied significantly, which has impacted the amount of proceeds we have generated. Further, the proceeds that we generate during any given period of time may not necessarily correlate with the prevailing market prices for the corresponding period of time, given a variety of factors, including that we have and may continue to contract sales on a forward basis, at a pre-determined price.

Additionally, we may at times contract commissioning cargos on a forward basis and, as a result, these sales of commissioning cargos may be uncorrelated with movements in spot LNG prices.

As a result, we have experienced, and expect to continue to experience during the remainder of the commissioning phase, significant volatility in the proceeds we have generated from the sales of commissioning cargos from the Calcasieu Project and the Plaquemines Project. Accordingly, the proceeds we have generated from such sales of commissioning cargos of the Calcasieu Project to date may not be indicative of the duration of the commissioning period or the amount of proceeds from such sales for any future period for the Calcasieu Project or for any of our other projects, including bolt-on expansions thereof. As a result, such proceeds, and also our operating results more generally, may vary significantly from one fiscal period to the next comparable fiscal period. Moreover, if we are not able to generate proceeds from the sale of commissioning cargos in the future that are comparable to such proceeds from the Calcasieu Project in the past, that could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity, and prospects.

Our ability to optimize sales of post-COD LNG cargos is subject to significant uncertainty and volatility in proceeds generated from such sales.

Our business strategy includes applying cash proceeds from one project to decrease the financing required for future projects. Our strategy is to optimize sales of LNG produced following COD by committing certain nameplate capacity to long-term post-COD SPAs, with the aim of creating a base of stable cash flows, while reserving the rest of a project's nameplate capacity to sell on a short-, medium-, or long-term basis with the goal of optimizing pricing for such capacity and balancing profit, duration and risk.

Our ability to optimize sales of LNG cargos that are not otherwise committed will depend on our ability to negotiate sales that meet our objective of balancing profit, duration and risk. There is no assurance that we will be able to successfully negotiate sales of such cargos on terms that are acceptable to us. In addition, because such cargos may be sold on varying terms, including in some instances on a forward basis, proceeds from such cargos may vary significantly from period-to-period and from project-to-project depending on, among other factors, prices and market conditions in the international LNG markets, global LNG freight rates, and on the timing of when a contract for sale is executed. Further, the amount of any proceeds that we may generate from such sales, and our profitability relating to such sales, is largely dependent on the strength of international LNG markets, as primarily reflected in the spot price for LNG at the time a contract for sale of such cargos is executed. Historically, the spot price for LNG has varied significantly, and we expect the spot price will continue to vary significantly in the future which will impact the amount of proceeds we generate from such sales. Further, we may at times contract such cargos on a forward basis and, as a result, such sales may be uncorrelated with movements in spot LNG prices.

As a result, we may experience significant volatility in any proceeds we generate from sales of post-COD LNG cargos at our projects, in particular if we reduce the proportion of such cargos that are committed under long-term SPAs. Moreover, if we are not able to effectively optimize sales of such cargos in the future, that could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

We have not entered into SPAs with customers for the total expected nameplate capacity at the CP2 Project, the CP3 Project, the Delta Project, or any potential bolt-on expansions, and our failure to enter into final and binding contracts for an adequate portion of, or to otherwise sell, the expected nameplate capacity of any of our projects, including any phases or expansions thereof, could impact our ability to take FID for such projects.

Our ability to generate revenue and cash flow is partially based on our ability to enter into long-term SPAs with customers with respect to the expected nameplate capacity of our projects. Changes in market conditions relating to, among other factors, the price of natural gas in the United States and the price of LNG in international markets could adversely affect the competitiveness of our projects and our ability to enter into such SPAs, which could adversely impact our potential revenues.

We are actively marketing a portion of the remaining expected nameplate capacity of the CP2 Project to leading international oil and gas companies, national and multinational utilities and LNG portfolio trading companies. As of December 31, 2024, the CP2 Project has contracted to sell 9.25 mtpa of LNG under eight 20-year SPAs. The obligation to make LNG available under these post-COD SPAs commences from the occurrence of COD for Phase 1 of the CP2 Project.

As of this date, we have not entered into any SPAs for the expected nameplate capacity for the potential bolt-on expansion capacity for the Plaquemines Project, the CP3 Project, and the Delta Project and have not yet begun actively marketing the expected nameplate capacity for such developments. While taking FID for a given project, including any phase or expansion thereof, is subject to numerous factors, we may elect to proceed with FID for the CP2 Project, the CP3 Project, the Delta Project, any potential bolt-on expansions, or any other future projects, including any phases or expansions thereof, only after we execute binding SPAs for such projects, phases, or expansions, that cover a targeted portion of the applicable nameplate capacity that we consider adequate to support the development and financing of such project, phase, or expansion. Our inability to take FID for any future development project or any phase or expansion thereof may result in a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and, prospects.

Our revenues and operating margins may be adversely affected if we are unable to produce and sell liquefaction capacity in excess of the nameplate capacity of our facilities.

A key element of our business strategy is to generate revenue from the sale of LNG produced at each of our projects in excess of the nameplate capacity of the relevant project after such project achieves COD.

We aim to develop and operate our LNG facilities to be capable of producing greater excess capacity, in most cases at least 30% of their guaranteed nameplate capacity. Our ability to produce LNG in excess of the nameplate capacity at each of our projects is subject to significant risks and uncertainties relating to the development, construction and commissioning of our projects as discussed in these "Risk Factors." Although we believe that our design and configuration will enable us to produce excess LNG without incurring material additional operating expenses or requiring additional capital investment, we may encounter additional, unforeseen costs, resulting in either operating expenses or capital investment, that make production of any excess LNG less economic or, potentially, uneconomic. Any increase in our incremental operating expenses or capital investments could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects. As a result, there can be no assurance that we will be successful in producing any such excess LNG at any of our projects on a consistent and reliable basis, or at all.

We generally plan to retain flexibility to sell any excess LNG on a spot basis, or on a short-, medium- or long-term basis. Our ability to sell any such LNG will be subject to a number of risks and uncertainties outside our control, and there can be no assurance as to when, or on what terms, we will be able to sell any such excess LNG, if at all. As a result, revenues from the sale of any such excess LNG may vary significantly depending on prices and conditions in the international LNG markets and depending on when a contract for sale is executed, and the terms of those contracts may not always be favorable.

To the extent we are unable to sell any such remaining LNG, our revenues will be adversely impacted, and any such impact could be significant. In addition, we will likely still be required to pay certain of our operating expenses related to the anticipated production of such remaining LNG (such as pipeline transportation costs) without generating any corresponding revenue. As a result, any such shortfall would also reduce our operating margins. Any of the foregoing could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

In addition, VG Commodities has contracted to resell at least 50% of the LNG generated by the Calcasieu Project in excess of its nameplate capacity (subject to an annual cap at the option of the counterparty). Pursuant to such agreement, the counterparty is entitled to an assignment of VG Commodities' rights under the applicable Intercompany Excess Capacity SPA in certain cases (including but not limited to when an event of default by VG Commodities has occurred and not been cured pursuant to such agreement with the counterparty). In addition, we may enter into similar arrangements related to the excess LNG at our other projects, including bolt-on expansions thereof, in the future.

Our customers or we may terminate our SPAs if certain conditions are not met or for other reasons.

Each of our SPAs contains or will contain various termination rights allowing our current and future customers to terminate, or be relieved from their contractual obligations under their SPAs including, without limitation:

- with respect to certain post-COD SPAs, the failure of certain conditions precedent to be satisfied or waived by a specified date, or delays in the occurrence of COD beyond a specified time period;
- if we fail to make available specified scheduled cargo quantities;
- upon the occurrence of certain extended events of *force majeure*;
- if we have been held liable in excess of certain liability caps and we did not agree to increase such liability caps as specified under the relevant SPA;
- our failure to satisfy our contractual obligations after an event of default and after any applicable cure periods; and
- the occurrence of certain change of control events.

For example, VGCP notified all customers under the Calcasieu Project post-COD SPAs of the anticipated delay to COD, indicating that such delay constitutes a *force majeure* event. As a result of such designation, the time period within which to achieve COD in such SPAs would be extended and such customers will not be entitled to terminate as a result of failure to designate COD until June 2025, at the earliest. All of such customers have questioned whether, and most have disputed in arbitration proceedings that, the delay constitutes a *force majeure* event, and they could assert that they are entitled to terminate their SPAs because COD did not occur by March 2024.

In addition, the CP2 Foundation SPAs include termination rights in favor of the customer and us if certain conditions precedent are not satisfied by us or waived by the customer by a certain date including that we receive all LNG export authorizations by that date. Because of the rehearing order issued by FERC on November 27, 2024 that required a supplemental environmental review and the delay in issuance of authorizations to proceed with construction on the CP2 Project until FERC issues a further merits order and the temporary pause on new authorizations of natural gas exports to Non-FTA Nations described under Item 1.—*Business*—*Governmental Regulation—DOE Export Authorizations*, some of our customers under the CP2 Foundation SPAs or we may elect to terminate such SPAs if the related conditions precedent are not satisfied by the applicable deadline. Such dates certain have passed in two of the CP2 Foundation SPAs and are upcoming in March 2025 in the remaining CP2 Foundation SPAs. Although most customers have agreed to extend their original deadlines until March 2025, we are negotiating extensions with all of the CP2 Foundation SPA customers. There can be no assurance that we will come to an agreement regarding an extension with such customers, and if we do not come to an agreement, either we or such customers may elect to terminate their respective SPA after the applicable grace period. Further, there can be no assurance that we will be able to secure any necessary extensions on similar terms with the CP2 Foundation SPA customers or at all if the future deadlines are not met in the event of further delays or otherwise.

While we could potentially replace any SPAs that are terminated by our customers or us, we may not be able to replace these SPAs on similar or favorable terms, or at all, if they are terminated. Further, under certain financing agreements, we may be required to maintain in effect (subject to our ability to replace them over a certain period of time that may extend up to 180 days) certain long-term SPAs for a particular project, and any breach of such requirement after the applicable grace period may, unless certain prepayments are made, result in an event of default under such agreements, as well as a cross-default under our other financing agreements for that project or otherwise. As a result, a termination of certain SPAs could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Our ability to generate cash under our post-COD SPAs is substantially dependent upon the performance by a limited number of our customers, and we could be materially and adversely affected if certain of these customers fail to perform their contractual obligations for any reason.

We expect to have a limited number of customers to whom we sell LNG on a post-COD basis. For example, as of December 31, 2024, we have executed 39.25 mtpa of post-COD SPAs with 20 customers with respect to LNG from our projects, of which 37.45 mtpa is contracted under 20-year fixed price SPAs and 1.8 mtpa is contracted on a short- and medium-term basis. For the year ended December 31, 2024, approximately 72% of our revenue for the period from individual external customers was concentrated across three customers. Moreover, for the year ended December 31, 2024, we had one customer which represented approximately 32% of our revenue for that same period.

The ability of our customers to perform their respective obligations to us will depend on numerous factors that are beyond our control. Our future results, our ability to service any debt we may incur and our liquidity are substantially dependent upon the performance of these customers under their contracts, and on such customers' continued willingness and ability to perform their contractual obligations. We are also exposed to the credit risk of any guarantor of the customers' obligations under their respective agreements if we must seek recourse under a guaranty. Any such credit support may not be sufficient to satisfy the obligations in the event of a counterparty default. In addition, if a controversy arises under an agreement resulting in a judgment in our favor where the counterparty has limited assets in the United States to satisfy such judgment, we may need to seek to enforce a final U.S. court judgment or arbitral award in a foreign tribunal, which could involve a more lengthy and less certain process and also result in additional costs.

Certain of our existing SPAs limit, and our future SPAs may limit, the liability of the relevant customer or its guarantor (or both). As a result, if a customer fails to perform its obligations under an LNG sales contract (including, for example, by failing to take or pay for the contracted volume of LNG), our ability to recover from that customer or from any guarantor of its obligations would be subject to any agreed upon limitations on liability. In addition, our existing SPAs excuse, and we expect that our future SPAs will excuse, performance by our customers upon the occurrence of *force majeure* events, such as certain severe adverse weather conditions, the breakdown or failure of its LNG tankers and acts of God.

Failures by certain of our customers to perform their obligations, or our inability to recover from such customers or the applicable guarantors, could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Our operating margins may be adversely affected if the price of natural gas decreases, if we pay a premium for feed gas relative to the contractual spot price we charge our customers, or as a result of inflationary pressures.

Our post-COD and other SPAs typically require, and we expect our future SPAs will require, our customers to pay a fee equal to a fixed facility charge per MMBtu, plus an amount equal to, depending on the applicable SPA, 115% or more of the Henry Hub price for feed gas that covers the cost of feed gas and is intended to cover gas transportation costs and certain of our other operating expenses. As a result, any decrease in the price of feed gas may reduce our operating margins under our SPAs.

In addition, there can be no assurance that the terms of our SPAs will pass through the actual price we pay for the supply and transport of feed gas to produce LNG under such SPAs. While we expect to manage our portfolio of gas supply to match the Henry Hub price we charge our customers under SPAs, there can be no assurance that we will be able to do so, particularly in times of volatility in the price of natural gas. If we are required to purchase feed gas at a premium relative to the Henry Hub price used to calculate the fee under the relevant LNG sales contract due to unexpected market factors or otherwise, our operating margins would be reduced.

We also anticipate that certain post-COD SPAs we enter into will include a fixed fee that will only be partially adjusted for inflation over the contract term. As a result, inflationary pressures over time will not be fully reflected in the prices we charge our customers under our post-COD SPAs. At the same time, our operating expenses are likely to increase due to inflationary pressure. Any such increases may not be fully offset by any partial inflation adjustments under our post-COD SPAs and, as a result, inflation may reduce our operating margins.

Any reduction in our operating margins as a result of these factors could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

We may not be able to purchase or receive physical delivery of sufficient natural gas to satisfy our delivery obligations under the SPAs, which could have a material adverse effect on us.

We depend upon third-party pipelines to provide gas delivery options to our projects and any other natural gas liquefaction and export facilities that we may decide to develop in the future. We have entered into several precedent and service agreements with interstate pipeline companies to provide the natural gas transportation to the Calcasieu Project and the Plaquemines Project. We have begun to contract for natural gas transportation requirements for the CP2 Project and are currently in negotiations with other gas transportation companies to provide further natural gas transportation requirements for the CP2 Project and the natural gas transportation requirements for the CP3 Project and the Delta Project. We will need to enter into and secure additional pipeline transportation capacity for the CP2 Project, the CP3 Project, the Delta Project, and potential bolt-on expansions for us to generate the expected nameplate and excess capacity of LNG at such projects. There can be no assurance that we will be able to enter into the requisite agreements to secure natural gas transportation capacity on terms acceptable to us, or at all, which would impair our ability to fulfill our obligations under any SPAs. Even if we have entered into the requisite agreements for our projects, there can be no assurance we will be able to secure the necessary natural gas transportation capacity for each of our projects.

In addition, we depend on third-party natural gas suppliers to provide the feed gas required to generate the expected nameplate and excess capacity of LNG at our projects. We anticipate that we will establish and maintain a portfolio of natural gas supply agreements or contracts to meet our requirements, which we have commenced for the Calcasieu Project and the Plaquemines Project, but there can be no assurance that we will be successful in doing so on a long-term basis.

We also cannot control the regulatory and permitting approvals or third parties' construction times, either with respect to capacity that has been secured or capacity that will be secured. If and when we need to replace one or more of our agreements with these interconnecting pipelines or enter into additional agreements, we may not be able to do so on commercially reasonable terms or at all, which would, in turn, impair our ability to fulfill our obligations under certain of our SPAs. Our failure to purchase or receive physical delivery of sufficient quantities of natural gas could prevent us from meeting our obligations under our SPAs and our ability to generate revenue would be adversely affected, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects. In addition, if we are unable to deliver any contracted volume in full, our customers will generally be entitled to reimbursement of costs and expenses for replacement LNG.

Total contracted revenue is based on certain assumptions and is presented for illustrative purposes only and actual sales under our SPAs may differ materially from such illustrative operating results.

We have included in this Form 10-K certain calculations of total contracted revenue as an illustrative metric reflecting revenue that could be generated under our post-COD SPAs as of a particular date for the remaining term of all such post-COD SPAs. These calculations are based on certain assumptions as described in the definition of "total contracted revenue" included under *Glossary of Key Terms* of this Form 10-K. Those assumptions include, among others, the development, completion and commissioning of each of the relevant projects (including obtaining any required regulatory approvals), estimated contracted volume for each project's existing post-COD SPAs, assumed rate of inflation, and an assumed Henry Hub gas price per MMBtu. Such assumptions are based upon our management's assessment of market comparables and other indicative pricing in the market and will be affected by various factors, including actual inflation rates and Henry Hub gas prices during the term of the relevant SPAs, performance by our customers under the applicable SPAs, as well as by the various risks and uncertainties relating to development, construction, commissioning and operation of each of our projects (including obtaining any required regulatory approvals) as described in this "Risk Factors" section. For example, actual inflation rates and actual Henry Hub gas prices during the term of the relevant SPAs will likely differ from the assumed rate of inflation and assumed Henry Hub gas price used in such calculation, and any such differences could be material. As a result, actual revenue generated under those SPAs will likely differ from the total contracted revenue included in this Form 10-K, and any such differences could be material. Investors should not place undue reliance on our illustrative calculations of the total contracted revenue.

We may not be successful in pursuing bolt-on expansion opportunities at our current projects, which would adversely impact our growth prospects.

A key element of our growth strategy is to increase the liquefaction capacity at certain of our projects through bolt-on expansions that involve adding incremental liquefaction trains and certain related equipment to the relevant project. Our ability to pursue any such bolt-on expansion is subject to a number of risks and uncertainties and there can be no assurance that we will be able to complete all or some of our currently anticipated bolt-on expansion opportunities.

In particular, bolt-on expansion opportunities are subject to regulatory approval, and as of the date of this Form 10-K, we have only recently requested initiation of the pre-filing process with FERC for such bolt-on expansion opportunities with respect to the Plaquemines Project and we have not otherwise made any filings with the necessary regulators, including DOE or FERC, with respect to any such expansion opportunities at our current projects. Such regulatory approvals are subject to numerous risks and uncertainties as described under *—Risks Relating to Regulation and Litigation*, and there can be no assurance that we will be successful in obtaining any such regulatory approvals. In addition, we are evaluating contracting and optimal financing options for any bolt-on expansions as there can be no assurance our projects will generate sufficient cash proceeds to fund all of the expansion opportunities we have identified at our current projects. Further, any bolt-on expansion will require sufficient additional natural gas supply at the relevant project, and there can be no assurance we will be able to enter agreements for supply or transportation of the requisite natural gas on terms acceptable to us or at all.

Additionally, the development and construction of any bolt-on expansions at our current projects could have an adverse effect on the ongoing construction, commissioning or operations, as applicable, of the relevant projects. The simultaneous construction and subsequent commissioning of any bolt-on expansion opportunities at any project while such project is otherwise in construction, commissioning, or operating at full capacity, could subject us and our third-party contractors to additional safety risks, as well as additional costs related to the management of those safety hazards and additional required regulatory approvals. Any such additional safety or other measures and approvals could result in additional costs, could delay our plans for any such expansions, or could result in a smaller size of any potential bolt-on expansion opportunity.

If we are not successful in pursuing bolt-on expansion opportunities that we have identified at our projects, or if any such expansion opportunities are executed only at a smaller scale or on a delayed timeline, our growth would be adversely impacted. Any of the foregoing could have an adverse effect on our growth, financial condition, operating results, and cash flow.

Seasonal fluctuations will cause our business and results of operations to vary among quarters, which could adversely affect our business and results of operations.

Our results of operations have fluctuated on a quarterly basis in the past, and may continue to fluctuate in the future, due to a wide variety of factors, including but not limited to the volatility in pricing and the seasonal nature of demand for natural gas and LNG, third-party supply disruptions, price spread between European and Asian LNG indices, the availability of, and associated freight rates of, LNG tankers and temperature and weather conditions across the markets we supply, which can have an impact on the demand for energy and, consequently, LNG. Accordingly, fluctuations in revenue during quarters of high and low demand, respectively could have a disproportionate effect on our results of operations for the entire year. Thus comparisons of our results of operations across different fiscal quarters may not be accurate indicators of our future performance. Annual or quarterly comparisons of our results of operations may not be useful and our results in any particular period will not necessarily be indicative of the results to be expected for any future period. While we believe that our results of operations and earnings potential should be analyzed on a longer term view due to the nature of our business, such fluctuations can adversely affect our business and results of operations.

Our limited diversification could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Substantially all of our anticipated revenue will be dependent upon our LNG projects, all of which are currently located in southern Louisiana. Due to our limited asset and geographic diversification, an adverse development at the terminal or pipeline for our projects (including, for example, natural or man-made disasters affecting Louisiana, or significant long-term equipment failures), or in the LNG industry, would have a significantly greater impact on our financial condition and operating results than if we maintained more diverse assets and operating areas.

In the ordinary course of our business, we explore acquisitions and other targeted investments in areas of the natural gas industry that relate to our natural gas liquefaction and export projects that could negatively affect our operating results, increase our debt or cause us to incur significant expense.

An element of our strategy is to support our LNG growth through targeted transactions in areas of the natural gas industry that relate to our natural gas liquefaction and export projects. We intend to continue to explore targeted investments and acquisitions in the natural gas industry that complement and strengthen our project portfolio and solidify access to, and transport for, natural gas molecules, and the ability to deliver LNG, at commercially attractive terms. For example, we have acquired firm regasification facility capacity at the largest LNG regasification terminal in Europe, Grain LNG, in the United Kingdom, which we expect will allow us to import 42 LNG cargos per year beginning, depending on the starting period, anytime between October 1, 2029 to April 1, 2030, to and until July 14, 2045 (except for the period from April 1, 2030 to September 30, 2030 when only 13 LNG cargos can be imported). Additionally, we have secured approximately 1 mtpa of LNG regasification capacity at the new Alexandroupolis LNG receiving terminal in Greece for five years, which is expected to begin on October 1, 2025. Our capacity will account for approximately 25% of the total terminal capacity at Alexandroupolis, or approximately 12 cargos annually. While we believe that these contracted regasification capacities will allow us to supply both LNG and regasified natural gas directly into the European market to current and future downstream customers and allow us to continue to grow our presence in the European markets, we cannot guarantee that demand for delivered LNG or regasified natural gas will be in line with our expectations.

We have limited experience with pursuing such expansions of our business through acquisitions or investments, which may be in areas to our business that relate to our natural gas liquefaction and export projects. Such acquisitions or investments may expose us to new risks not presently faced by our business. If we make any acquisitions, we may not be able to integrate these acquisitions successfully into our existing business, and we could assume unknown or contingent liabilities. In addition, we may enter into agreements with counterparties outside the U.S., which would expose us to political, governmental, and economic instability, foreign currency exchange rate fluctuations and corruption risk, all of which could be exacerbated by our lack of experience doing business in such other markets. Any future acquisitions also could result in the incurrence of debt, potential violations of covenants in our debt instruments, contingent liabilities, insufficient revenue acquired to offset liabilities assumed, unexpected expenses, inadequate return of capital, regulatory or compliance issues, potential infringements, difficulties integrating such acquired companies into our operations, and other unidentified issues not discovered in due diligence or future write-offs of intangible assets or goodwill, any of which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects. Integration of an acquired company also may disrupt ongoing operations and require management resources that we would otherwise focus on developing our existing business and projects. We may experience losses related to investments in other companies, and we may not realize the anticipated benefits of any acquisition, strategic alliance or joint venture. Accordingly, if such initiatives are not successful, this could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Severe weather events, hurricanes, or other disasters could result in an interruption of our operations, a delay in the completion of our projects, higher construction costs and the deferral of the dates on which we would become entitled to receive payments under any SPAs, all of which could adversely affect us.

Severe weather, including hurricanes and winter storms, can be destructive, causing construction delays, outages and property damage that require incurring additional expenses. Furthermore, our operations could be adversely affected, and our physical facilities could be at risk of damage, should changes in global climate produce, among other conditions, unusual variations in temperature and weather patterns, resulting in more intense, frequent and severe weather events, abnormal levels of precipitation or a change in sea level or sea temperatures. Although the current design of each of our projects includes perimeter walls to protect against storm surge, there can be no assurance that they will be effective to protect against any of these events. In particular, all of our LNG projects that are currently under construction or development are in Southern Louisiana, which has historically been exposed to severe weather events and hurricanes. For example, in August and October 2020, respectively, Hurricanes Laura and Delta struck the Louisiana coast, with Hurricane Laura passing directly over the Calcasieu Project site.

Future storms and related storm activity and collateral effects, or other disasters such as explosions, fires, floods or accidents, could result in damage to, or interruption of operations at, our projects or related infrastructure, as well as delays or cost increases in the construction and the development of our projects and following the completion of our projects, interruption of operations of our projects. Changes in the global climate may have significant physical effects, such as increased frequency and severity of storms, floods, and rising sea levels. If any such effects were to occur, they could have a material adverse effect on our operations.

We are unable to insure against all potential risks and may become subject to higher than expected insurance premiums. In addition, we retain certain risks as a result of insurance through our captive insurance.

Although we have obtained certain customary insurance coverage in respect of the Calcasieu Project, the Plaquemines Project, and the CP2 Project and our LNG tankers, we do not currently maintain insurance with respect to most aspects of the development, construction or operation of our other projects. We expect to obtain insurance as required under our contracts and consistent with industry standards (subject to availability on commercially reasonable terms) to protect against certain construction, operating and other risks, but not all risks will be insured or are insurable (for example, losses as a result of *force majeure*, natural or man-made disasters, terrorist attacks or sabotage or environmental contamination may not be available at all or on commercially reasonable terms). However, there can be no assurance that such insurance coverage will be available in the future on commercially reasonable terms or at commercially reasonable rates, or on the same or substantially similar terms as our existing insurance coverage or that the insurance proceeds will be adequate to cover the repair or replacement of equipment and materials, to cover lost revenues from our projects, or to compensate for any injuries or loss of life. Further, we use a captive insurance subsidiary to insure certain risk related to named windstorms and such coverage involves retaining certain risks that might otherwise be covered by traditional insurance. If certain operating risks occur, or if there is a total or partial loss of a project in the future, there can be no assurance that the proceeds of the applicable insurance policies will be adequate to cover lost revenues, increased expenses or the cost of repair or replacement. Additionally, in the event we make a claim under our insurance policies, we will be subject to the credit risk of the insurers. Volatility and disruption in the financial and credit markets may adversely affect the credit quality of our insurers and impact their ability to pay claims. Any increases in the number or severity of claims or any such loss that is not covered by our insurance policies could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

We anticipate that insurance premiums for LNG projects may increase due to a continuing increase in demand by LNG projects seeking insurance coverage, and losses and claims that have arisen or been experienced in respect of other unrelated projects in other regions or losses and claims that are large enough to impact the broader insurance market. Furthermore, we anticipate insurance premiums for projects located in Louisiana may increase significantly following the occurrence of future major hurricane damage in the region. Changes in global climate may produce, among other possible conditions, unusual variations in temperature and weather patterns, resulting in more intense, frequent and severe weather events, abnormal levels of precipitation or a change in sea level or sea temperatures. Future storms and related storm activity and collateral effects, or other disasters such as explosions, fires, floods or accidents, could result in further increases in insurance premiums. Any such increases in premiums could be significant and could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

A major health and safety incident relating to our business could be costly in terms of potential liabilities and reputational damage.

Health and safety performance is critical to the success of all areas of our business. Any failure in health and safety performance may result in personal harm or injury, damage to property, fines or penalties for non-compliance with relevant regulatory requirements or litigation, and a failure that results in a significant health and safety incident is likely to be costly in terms of potential liabilities. Such a failure could generate public concern and have a corresponding impact on our reputation and our relationships with relevant regulatory agencies and local communities.

Failure to retain and attract executive officers and other skilled professional and technical employees or increased labor costs could have a material adverse effect on our operations.

Our business strategy is dependent on our ability to recruit, retain and motivate employees. Competition for skilled management employees for our various business and administrative operations is high. In addition, demand for skilled professional, technical and operations employees is high in the fields of engineering, construction, operations and gas transportation. Demand for these employees is high due to growth in demand for natural gas, increased supply of natural gas as a result of developments in gas production, increased infrastructure projects, and increased regulation of these activities. There can be no assurance that we will successfully recruit or retain qualified personnel, and our inability to retain and attract these employees could adversely affect our business and future operating results.

Furthermore, while most of our executive officers are required to devote substantially all of their time to our business, if other business interests of our executive co-chairmen require them to devote substantial amounts of time elsewhere, it could limit their ability to devote time to our business which may have a negative impact on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Our operating results depend in significant part upon the continued contributions of key senior management and technical personnel. Continued successful operation of our projects and management of growth requires, among other things:

- continued development of financial and management systems;
- implementation of adequate internal control over financial reporting and disclosure controls and procedures;
- hiring and training of new personnel; and
- coordination among logistical, technical, accounting, finance, information technology, administrative, and commercial personnel.

An inability to successfully manage any of these factors could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity, financing requirements and prospects.

We are dependent on the strategic direction of Michael Sabel, our Chief Executive Officer, Executive Co-Chairman of the Board and Founder, and Robert Pender, our Executive Co-Chairman, Executive Co-Chairman of the Board and Founder.

Mr. Sabel and Mr. Pender are, through VG Partners, our controlling shareholders, and therefore have significant influence on, and are drivers of, our business planning, strategy, and culture. Our success depends to a significant degree on their leadership, long-term vision, relationships, knowledge of the industry, and ability to execute our overall business strategy. If either Mr. Sabel or Mr. Pender were to discontinue their service with us due to death, disability or any other reason, it could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

We and our contractors, including our EPC contractors, may experience increased labor costs, and the unavailability of skilled workers or our failure to attract and retain qualified personnel could adversely affect us.

Before construction of any project begins, we and our contractors, including our EPC contractors, need to hire new on-site employees to manage the construction of each project. We have engaged an EPC contractor to meet some of the construction labor needs of the Plaquemines Project and Phase 1 of the CP2 Project. In addition, before any of our projects commences operations, we need to hire an entire staff to operate the applicable facility. As a result, we expect the number of our personnel and our related costs to continue increasing significantly as we grow. If we and our contractors, including EPC contractors, are not able to attract and retain qualified personnel, this could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Construction, operation and maintenance of our facilities requires highly skilled personnel. There may be a limited supply of such personnel as a result of many factors, including intense competition to attract and retain the services of such persons. This competition may increase as additional LNG projects and other large-scale infrastructure projects are developed and constructed in North America, and in particular, the Gulf Coast of the United States. As a result, we and our contractors, including EPC contractors, may face shortages of qualified labor to construct, manage and operate our facilities, higher than anticipated labor costs or an inability to monitor, motivate and retain qualified personnel. An inability to recruit and retain such individuals could decrease productivity in the construction of our projects and in our operations. Competition for skilled employees could require us and our contractors, including EPC contractors, to pay higher wages, which could also result in higher labor costs.

Moreover, a shortage in the labor pool of skilled workers and other general inflationary pressures, which we and our contractors, including EPC contractors, have experienced in the past, and may continue to experience in the future, or changes in applicable laws and regulations could make it more difficult to attract and retain qualified personnel and could require an increase in the wage and benefits packages that are offered, thereby increasing our operating costs. Any increase in our operating costs could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

We use and are planning to utilize various tax incentive programs the State of Louisiana offers that may not continue to be available or may be available in diminished form.

The State of Louisiana has various programs in place to incentivize investment in the state. These include sales tax rebates or exemptions, payroll tax credits, investment tax credits, inventory tax credits, and property tax exemptions. We have utilized such tax incentives where available for our existing projects and are planning to seek these tax benefits as well as any other tax benefits available to our other projects, including bolt-on expansions thereof. However, owing to the fiscal difficulties the state has faced in recent years, some of these programs have come under scrutiny and, as a result, the benefits provided by those programs have been reduced. In addition, applicants for these benefits have been subjected to greater scrutiny by the state, and have been subjected to a greater burden in demonstrating that they meet the criteria (such as job creation requirements) for the award of such benefits. Furthermore, the grant of certain of these benefits may be challenged in court.

If such lawsuits were to prevail or we are otherwise unable to secure the benefit of any of these incentive programs, or if there are further reductions to the benefits provided by these incentive programs, the financial performance and results of operations and our plans for our projects may be adversely impacted.

Risks Relating to Our Projects and Other Assets

We will require significant additional capital to construct and complete certain of our projects, and we may not be able to secure such financing on time with acceptable terms, or at all, which could cause delays in our construction, lead to inadequate liquidity and increase overall costs.

We are in the process of commissioning the Calcasieu Project, constructing and commissioning the Plaquemines Project and developing the CP2 Project, the CP3 Project, the Delta Project and the potential bolt-on expansion for the Plaquemines Project. An amount expected to be necessary to complete the Calcasieu Project and achieve COD for the Calcasieu Project is held in cash reserve accounts pursuant to our project financing arrangements and reflected as restricted in our financial statements. While we believe we have sufficient cash and access to substantial commissioning cargo proceeds to fund the completion of the Plaquemines Project based on our current estimate of the total project costs, the CP2 Project, the CP3 Project, the Delta Project and any potential bolt-on expansions, as well as any future projects we develop, will require significant additional funding.

We currently estimate that the total project costs for the Plaquemines Project will be approximately \$23.3 billion to \$23.8 billion including EPC contractor profit and contingency, owners' costs and financing costs, of which approximately \$19.8 billion had been paid for as of December 31, 2024. As of December 31, 2024, we have additional available borrowing capacity of \$313 million under the Plaquemines Construction Term Loan. In addition, as of December 31, 2024, we estimate that the total project cost for the CP2 Project will range from approximately \$27.0 billion to \$28.0 billion, including EPC contractor profit and contingency, owners' costs and financing costs, substantially all of which have not yet been funded. These estimates are based primarily upon our construction cost experiences with the Calcasieu Project and the Plaquemines Project and the pricing included in the CP2 Phase 1 EPC Contract, and reflect the current inflationary environment as well as the fact that the pipeline for the CP2 Project is expected to be longer and more expensive than the pipelines for the Calcasieu Project and the Plaquemines Project. However, we have not yet entered into a number of material contracts for the CP2 Project (including an EPC contract for Phase 2 of the CP2 Project), and our actual costs could vary significantly from our preliminary estimates depending on the terms we may agree to for those contracts. Further, these cost estimates do not include the cost of any potential bolt-on capacity at the Plaquemines Project or the CP2 Project, nor do they reflect the potential impact of any new tariffs that have been announced or implemented since December 31, 2024 or that may be implemented in the future. Our project budget estimates included in this Form 10-K reflect all tariffs in place, and Section 232 exemptions secured, as of December 31, 2024. Certain of our key components, including our Baker Hughes sourced liquefaction train system modules and power island components, are foreign sourced and specified under our regulatory approvals, offering no domestically sourced alternative and potentially exposing us to the effects of any future tariffs that may be imposed. There can be no assurance as to the extent of any future tariffs, or the impact thereof on any of our estimates of total project costs for our projects, which could have a material adverse effect on our construction budgets and limit our growth prospects.

Moreover, no substantial construction work has been undertaken on either the CP3 Project or the Delta Project to date, we have not yet entered into a number of material contracts (including EPC contracts) for the CP3 Project or the Delta Project, and our actual costs could vary significantly from the costs of our other projects depending on the terms we may agree to for those contracts. There is no guarantee that we will be able to enter into the necessary contracts to construct the CP3 Project, the Delta Project, or any other natural gas liquefaction and export facility we may decide to develop in the future, on the same or substantially similar terms as the Calcasieu EPC Contract, the Plaquemines EPC Contracts or the CP2 Phase 1 EPC Contract. As a result, our cost estimates are only an approximation of the actual costs of construction and financing for such projects.

Our actual project costs may be higher, potentially materially, compared to our current estimates as a result of many factors as described under *—Our estimated costs for our projects have been, and continue to be, subject to change due to various factors.* For example, our cost estimates might change due to factors such as unexpected delays in the construction or commissioning of our projects, the execution of any repair or warranty work and change orders or amendments to certain material construction contracts, including final terms of or amendments to any EPC contract for such projects, and/or other construction or supply contracts. Accordingly, we will need to obtain significant additional funding from one or more sources of debt and equity financing before we are able to generate sales and/or revenue for our projects, other than the Calcasieu Project and the Plaquemines Project.

The amount of project-level equity funding that is required for any of our projects relative to the amount of project-level debt financing may differ between our projects. Generally, we expect to finance approximately 50% to 75% of the anticipated project costs of each of our projects with project-level debt financing (which may include limited recourse debt), and the remaining 25% to 50% with project-level equity (which may consist of equity contributions by us, equity financing transactions, mezzanine financing and/or other similar financing alternatives). However, the proportion of project-level debt to equity funding will depend on various factors, including market conditions and the amount of long-term contracted revenues for the relevant project. As a result, there can be no assurance as to the ultimate amount of project-level debt financing that will be available to us for a particular project on acceptable terms, which could have an adverse impact on our ability to finance the relevant project and may require us to raise additional debt, equity or equity-linked financing above relevant project entities, including potentially at the Company level, through additional debt, equity or equity-linked financing. We do not currently have any committed project-level debt or equity financing for the CP2 Project, the CP3 Project, the Delta Project or any potential bolt-on expansions. We may consider alternative structures to raise capital for those projects and, as a result, there can be no assurance that the financing structure for the CP2 Project, the CP3 Project, the Delta Project or any future project or expansions we may develop will be similar to those used for the Calcasieu Project and Plaquemines Project.

Additional capital may not be available in the amounts required, on favorable terms, or at all. In addition, if any adverse findings are discovered at any stage during the course of our development of our projects that would render part of, or all of, any such sites to be unsuitable or we discover flaws that may decrease the value of such sites as collateral for purposes of any financing, then we may not be able to obtain the financing necessary to construct the relevant project on favorable terms, or at all. For example, such adverse findings may include the discovery of environmental conditions on the relevant project site that require investigation, remediation or other changes to the relevant project or that make it more difficult for us to obtain the necessary regulatory approvals.

Furthermore, any adverse changes in natural gas demand that affect the competitiveness of LNG or any failure on our part to obtain or comply with necessary permits or approvals may also hinder our ability to obtain necessary additional capital or financing.

Delays in the construction of our projects beyond the estimated development period, issues with the commissioning process leading to additional repair and replacement work, as well as change orders to certain material construction contracts and/or other construction or supply contracts, could increase the cost of completion beyond the amounts that we estimate and beyond the then-available proceeds from sales of commissioning cargos we expect to receive, which could require us to obtain additional sources of financing to fund our operations until our projects are fully completed (which could cause further delays). For example, we have experienced unexpected delays in commissioning the Calcasieu Project related to certain necessary repairs and replacements. As a result, COD for the Calcasieu Project has been delayed while significant work related to commissioning, carryover completions, rectification, and certain other items is completed. We currently anticipate that COD for the Calcasieu Project will occur on April 15, 2025. Further, while we are generating commissioning cargo proceeds at the Calcasieu Project and plan to also sell commissioning cargos at each of our other projects, it is possible those commissioning cargo proceeds will be lower, potentially materially, than we currently anticipate, which could also require us to obtain additional sources of capital to fund development, construction and commissioning of our projects.

Our future liquidity may also be affected by the timing and availability of financing in relation to the incurrence of construction costs for our projects and other outflows and by the timing of receipt of cash flow under the SPAs in relation to the incurrence of various project and operating expenses. Moreover, many factors (including factors beyond our control) could result in a disparity between liquidity sources and cash needs, including factors such as construction delays and breaches of agreements.

Our ability to obtain financing that may be needed to provide additional funding will depend, in part, on factors beyond our control and there can be no assurances that funding will be available to us on commercial terms or at all. For example, capital providers or their applicable regulators may elect to cease funding LNG projects or certain related businesses. Accordingly, we may not be able to obtain financing on terms that are acceptable to us, or at all. Even if we are able to obtain financing, we may have to accept terms that are disadvantageous to us or that may have an adverse impact on our business plan and the viability of the relevant project. The failure to obtain any necessary additional funding could cause any or all of our projects to be delayed or not be completed. Any delays in construction could prevent us from commencing operations when we anticipate and could prevent us from realizing anticipated cash flows, all of which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

We may not construct or operate all of our proposed LNG facilities or pipelines or any additional LNG facilities or pipelines beyond those currently planned, and we may not pursue some or any of the bolt-on expansion opportunities we have identified at our current projects, which could limit our growth prospects.

We may not construct some of our proposed LNG facilities or pipelines, and we may not pursue some or any of the bolt-on expansion opportunities we have identified at our current projects, in each case whether due to lack of commercial interest, inability to obtain financing, inability to obtain adequate supply of materials and equipment to complete construction of our projects, inability to obtain necessary regulatory approvals (including as a result of political factors, environmental concerns or public opposition) or otherwise. Our ability to develop additional liquefaction facilities or to pursue bolt-on expansion opportunities at our projects will also depend on the availability and pricing of LNG and natural gas in North America and other places around the world. If we are unable or unwilling to construct and operate additional LNG facilities or bolt-on expansion opportunities at our current projects, our prospects for growth will be limited.

When completed, our natural gas liquefaction and export projects, including the Calcasieu Project, the Plaquemines Project, the CP2 Project, the CP3 Project, the Delta Project, and any future projects or expansions thereof we develop, may face significant operational risks.

As more fully discussed in these "Risk Factors", the Calcasieu Project, the Plaquemines Project, the CP2 Project, the CP3 Project, the Delta Project, any potential bolt-on expansions and any other natural gas liquefaction and export facilities that we may decide to develop in the future involve operational risks, including the following:

- explosions, pollution, releases of toxic substances;
- the facilities performing below expected levels of efficiency;
- breakdown or failures of equipment;
- unanticipated changes in domestic and international market demand for and supply of natural gas and LNG, which will depend in part on supplies of and prices for alternative energy sources and the discovery of new sources of natural resources;
- operational errors by vessel or tug operators;
- operational errors by us or any contracted facility operator;
- labor disputes; and
- weather-related interruptions of operations, natural disasters, fires, floods, accidents or other catastrophes.

If any of such operational risks materializes, it could have a material adverse effect on our current or future business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

We have multiple procurement and construction contracts. Failure by one contractor to perform under its applicable material procurement and/or construction contract could lead to failure to perform or delay in performance by others under their construction contracts.

Our strategy for each project involves us entering into and administering a number of procurement and construction contracts, which differs from certain other LNG projects of this scale developed in the United States.

Failure of any of the counterparties to these procurement and/or construction contracts to complete its contractual obligations on a timely basis could result in material delays in the ability of our projects to achieve commercial operation. In addition, any such failure by any of the foregoing counterparties could affect the schedule of other construction contractors and/or require change orders to multiple material construction contracts. Although the scope of each such contractor is defined in the applicable material contract to which it is a party, in the event of delays or other procurement or construction issues, each such contractor may seek to shift responsibility for delays or other issues to other contractors, resulting in increased costs or delays.

We are dependent on our contractors for the successful completion of our projects and any bolt-on expansion opportunities at our projects that we may pursue, and any failure by our contractors to perform their contractual obligations could have a material adverse impact on our projects.

There is limited recent industry experience in the United States regarding the construction or operation of mid-scale natural gas liquefaction and export facilities. Timely and cost-effective completion of our projects or any bolt-on expansion opportunities at our projects in compliance with agreed upon specifications is highly dependent upon the performance of our contractors pursuant to their agreements with us. Moreover, our construction strategy involves multiple construction contracts, which differs from certain other LNG projects of this scale developed in the United States. Failure by one contractor to perform under its applicable material construction contract could lead to failure to perform or delay in performance by others under their construction contracts.

Successful construction and operation of our projects, or any bolt-on expansions at our projects, will depend on the adequacy and timeliness of performance of our contractors. The failure of our contractors to perform as expected could have a material adverse impact on our ability to complete our projects, or any bolt-on expansions at our projects, on our anticipated schedule and budget, or at all. Further, if the completion and the commercial operation dates of the Calcasieu Project or the Plaquemines Project are delayed beyond an agreed date certain for each project, an event of default under the Calcasieu Pass Credit Facilities, the VGCP Senior Secured Notes and the Plaquemines Credit Facilities may occur. See *—Risks Relating to Our Indebtedness and Financing—Upon the occurrence of an event of default under our existing and future indebtedness, our lenders and the holders of our debt securities could elect to accelerate all or a portion of our debt. A delay in COD of the Calcasieu Project or Phase 1 or 2 of the Plaquemines Project beyond a certain deadline could also result in an event of default under the Calcasieu Pass Credit Facilities or the Plaquemines Credit Facilities, respectively, and/or certain investors exercising step-in rights to control, directly or indirectly, certain of our subsidiaries and the Calcasieu Project.*

Further, our ability to complete our projects, or any bolt-on expansions at our projects, and commence operations at each of our projects, or any bolt-on expansions at our projects, depends on completion of construction of our projects, or any bolt-on expansions at our projects, in accordance with our design and quality standards. Faulty construction that does not conform to those standards could have a material impact on our ability to complete our projects, or any bolt-on expansions at our projects, on our anticipated schedule, and could also have material adverse effects on the operation of the facilities (for example, improper equipment installation may lead to a shortened life of our equipment, increased operations and maintenance costs or a reduced availability or production capacity of the affected facility).

Timely and cost-effective completion of the projects, or any bolt-on expansions at our projects, in compliance with agreed specifications is central to our business strategy and is highly dependent on the performance by the construction contractors of their obligations under the material construction contracts. The ability of our current or intended contractors to complete our projects in accordance with our design and quality standards and on our anticipated schedule is dependent on a number of factors, including such construction contractor's ability to, as applicable:

- maintain its own financial condition, including adequate working capital, and its ability to pay debt service and other liabilities;
- accurately estimate certain costs, including material, construction and fabrication costs, from third parties such as suppliers and subcontractors;
- respond to difficulties such as equipment failure, increased costs, delivery delays, schedule changes and failure to perform by subcontractors, some of which are beyond their control;
- design, engineer and build the facilities constituting the projects to operate in accordance with specifications and on schedule;
- engage and retain third-party subcontractors and procure equipment and supplies;
- attract, develop and retain skilled personnel, including engineers, and address any labor issues that may arise;
- respond to market conditions in the construction industry, including recent shortages of personnel and recent increases in operating costs;
- address any start-up and operational issues that may arise in connection with the commencement of commercial operations;
- post and maintain required construction bonds or other performance assurance and comply with the terms thereof; and
- manage the construction process generally, including coordinating with other contractors, third-party contractors and regulatory agencies.

Although agreements with our contractors may provide for liquidated damages if the relevant contractor fails to perform its obligations under the applicable agreement, such failure may delay or permanently impair the operations of our projects, or any bolt-on expansions at our projects. Moreover, any liquidated damages that we may be entitled to receive may be subject to certain liability caps, and may not be sufficient to cover the damages that we suffer, or that we may be required to pay to our customers or our lenders as a result of any such delay or impairment. Furthermore, we may have disagreements with our current or intended contractors about different elements of the construction process or our construction contracts, which could lead to the assertion of rights and remedies under the related contracts resulting in increases to the cost of the project, or any bolt-on expansions at our projects, or such contractor's unwillingness to perform further work on our projects, or any bolt-on expansions at our projects, or to pay liquidated damages. For example, VGCP had disagreements regarding certain disputed costs and bonuses with Kiewit, our EPC contractor for the Calcasieu Project that were submitted to arbitration. Such disputes were fully resolved in 2024 and resulted in the payment by us of approximately $320 million, in the aggregate, to Kiewit.

In addition, if our current or intended contractors, or any of their parents or affiliates that provide performance guarantees, letters of credit or similar credit support, consummate any significant acquisitions, dispositions, restructurings or other strategic transactions, or become subject to bankruptcy or similar proceedings, our ability to complete our projects, or any bolt-on expansions at our projects, in accordance with our design and quality standards and on our anticipated schedule, and our ability to recover under any such performance guarantees, letters of credit or similar credit support, may be adversely affected.

For example, the Plaquemines Project is being constructed pursuant to two integrated EPC contracts, one per phase, or the Plaquemines EPC Contracts, that VGPL entered into with KZJV, LLC, or KZJV, a limited liability company that is owned by Kellogg Brown & Root LLC, or KBR EPC Member, and Zachry Industrial, Inc., or Zachry Industrial. In May 2024, Zachry Industrial, along with Zachry Holdings, Inc., or Zachry Holdings, one of the parent guarantors under the Plaquemines EPC Contracts for the Plaquemines Project, and certain of their affiliates filed for bankruptcy protection under Chapter 11 of the U.S. bankruptcy code, or the Zachry Bankruptcy. In February 2025, Zachry Industrial and its affiliates had their Chapter 11 plan confirmed by the bankruptcy court. Although it is our understanding that KZJV, Zachry Industrial, and KBR EPC Member are committed to avoiding any disruption to the Plaquemines Project, and that Zachry Industrial has assumed the Plaquemines EPC Contracts following its bankruptcy proceedings, there can be no assurance that the Zachry Bankruptcy will not have a material adverse impact on the project. In addition, the Zachry Bankruptcy may result in the exercise of any applicable termination or step-in rights in connection with the KZJV limited liability company agreement and any related arrangements as well as disputes between KBR EPC Member and Zachry Industrial, or their parent guarantors, with respect to the KZJV joint venture and their respective obligations in connection with the Plaquemines EPC Contracts, which may adversely impact KZJV's, its members' or its parent guarantors' willingness or ability to perform their respective contractual obligations in connection with the Plaquemines EPC Contracts and related parent guarantees. Such events may also constitute an event of default under the Plaquemines EPC Contracts. If KZJV is unable or unwilling to perform according to the negotiated terms and timetable of the Plaquemines EPC Contracts, we may decide to engage a substitute EPC contractor, which could result in material cost increases and/or delays in the ability of both phases of the Plaquemines Project to achieve commercial operations. There also can be no assurance that we would be able to enter into an EPC contract with any such substitute EPC contractor on similar terms, or at all. Further, the Zachry Bankruptcy resulted in an event of default under the related project financing for the Plaquemines Project. While the relevant lenders waived such event of default, there can be no assurance they would waive any further events of default that occur in the future, and the occurrence of any such further event of default, if not waived, would allow the lenders to accelerate such project financing and foreclose on the collateral securing such financing. Any of the foregoing could result in material delays or termination of the Plaquemines Project, and could have a material adverse impact on our ability to complete the Plaquemines Project on our anticipated schedule and budget, or at all.

If any contractor or supplier is unable or unwilling to perform according to the negotiated terms and timetable of its respective agreement for any reason or terminates its agreement, we would be required to engage a substitute contractor or supplier. This would likely result in significant project delays and increased costs, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

We have not entered into all of the definitive agreements for the CP2 Project, the CP3 Project or the Delta Project, and there can be no assurance that we will be able to do so on a timely basis or on terms that are acceptable to us.

To date, we have not yet entered into all of the necessary definitive agreements with the key suppliers and contractors necessary for development and construction of the CP2 Project. Further, we have not entered into any of the necessary definitive agreements with the key suppliers and contractors necessary for the development and construction of the CP3 Project and the Delta Project other than the Baker Hughes Master Agreement. In particular, we have not yet entered into an EPC contract for Phase 2 of the CP2 Project, the CP3 Project, the Delta Project, or the potential bolt-on expansion for the Plaquemines Project. We may not be able to successfully negotiate the outstanding necessary definitive contracts for the CP2 Project, the CP3 Project or the Delta Project, or other projects or expansions we may develop in the future, on a timely basis or on terms or at prices that are acceptable to us. Our inability to negotiate and execute definitive agreements with such contractors on a timely basis or on terms acceptable to us could have a material adverse impact on our ability to complete the CP2 Project, the CP3 Project or the Delta Project, and any projects or expansions we may develop in the future, on our anticipated schedule and budget, or at all. Moreover, the development and construction of Phase 2 of the CP2 Project, the CP3 Project or the Delta Project, or any expansions thereof, may be delayed or they may not be built at all, and the construction cost of the CP2 Project, the CP3 Project or the Delta Project, or any expansions thereof, may be greater than our current estimates.

Any of the foregoing could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Certain of our contractual arrangements relating to development and construction of our projects include termination rights that, if exercised, could have a material adverse impact on our projects.

Certain of our contractual arrangements relating to the development and construction of one or more of our projects include termination rights or changes to the applicable pricing, or will automatically expire, if certain conditions are not met by specified deadlines.

For example, under the Baker Hughes Master Agreement, if we fail to enter into purchase orders for the liquefaction systems and the power plant for our future development projects by certain mutually agreed dates or to begin making scheduled payments, then Baker Hughes' obligations to supply such equipment will expire unless Baker Hughes agrees to extend those dates. In addition, Baker Hughes has agreed to reserve manufacturing capacity for purposes of fabricating equipment to be supplied under the agreement. While we have executed the applicable purchase orders for the Plaquemines Project and the CP2 Project, we have not yet executed any such purchase orders for the potential bolt-on expansion for the Plaquemines Project, the CP3 Project or the Delta Project. If we do not execute applicable purchase orders by the applicable dates in the agreement, Baker Hughes may utilize the relevant manufacturing capacity for other purposes and delivery of equipment by Baker Hughes under the agreement could be delayed. Based on our anticipated project schedule, we currently expect that we will be in a position to deliver the purchase orders for the CP3 Project, and the purchase orders for the Delta Project to Baker Hughes by the applicable deadlines in the Baker Hughes Master Agreement, as such deadlines may be amended from time to time. However, if a project is delayed for any reason (including the reasons described elsewhere in this "Risk Factors" section), Baker Hughes' obligations with respect to the remaining equipment to be delivered would expire unless we either (i) deliver the applicable purchase order and commence making payments on the agreed schedule, or (ii) agree with Baker Hughes on an extension of the applicable deadline under the agreement. There can be no assurance that we would be able to negotiate any such extension on terms that are acceptable to us or at all, or that we will have the financial resources to make the scheduled payments with respect to a purchase order prior to commencement of construction and financing of the relevant project.

The termination of any of the definitive agreements we have entered into with contractors, or any change to the pricing under those agreements, could have a material impact on our ability to complete the Plaquemines Project, the CP2 Project, the CP3 Project or the Delta Project, or any expansions thereof, on our anticipated schedule or budget, or at all.

Our estimated costs for our projects have been, and continue to be, subject to change due to various factors.

Our cost estimates for LNG facilities, related equipment and components, natural gas pipelines, LNG tankers, and other natural gas liquefaction and export facilities have been, and continue to be, subject to change due to many factors outside of our control. Such factors include, among other things, (i) inflationary factors, (ii) changes in commodity prices (particularly nickel and steel), (iii) escalating labor costs, (iv) supply chain availability, including the availability of critical components and increased costs to locate and procure alternatives, (v) labor disputes, (vi) tariffs, (vii) unexpected delays in construction or commissioning, (viii) unexpected repair, replacement, rectification and warranty work, and (ix) resolving contract closeout and true-up matters. Such factors have in the past resulted in, and may in the future result in, among other things, delays in construction or commissioning, repair or warranty work, cost overruns, and/or change orders under or amendments to existing or future construction contracts. Further, we may decide or be forced to enter into amendments to construction and/or supply contracts or submit change orders to the applicable contractor that could result in longer construction periods, higher costs or both. We may also decide or be forced to expend additional funds in order to maintain construction schedules, complete construction and commissioning, or comply with existing or future environmental or other regulations. Additionally, our estimated costs for our projects do not include the potential costs of any new tariffs that have been implemented since December 31, 2024 or that may be implemented in the future or estimated costs for any potential bolt-on expansion opportunities that we may pursue in the future. As a result, costs to achieve completion of LNG facilities, related equipment and components, natural gas pipelines, LNG tankers, and other natural gas liquefaction and export facilities may be higher, potentially materially, than our cost estimates. In the event we experience any such increases in estimated costs, delays or both, the amount of funding needed to complete an LNG facility, a phase thereof, related equipment and components, natural gas pipelines, LNG tankers, and other natural gas liquefaction and export facilities, could exceed our available funds and result in our failure to complete such projects or assets and thereby negatively impact our business and limit our growth prospects.

We currently expect that the remaining project costs to achieve COD for the Calcasieu Project will be funded with cash we hold in reserve accounts pursuant to our project financing arrangements, which is reflected as restricted cash in our financial statements. However, there is no assurance as to whether the amount of cash held in these accounts will be sufficient to complete the construction of the Calcasieu Project and achieve COD, including, for example as a result of any additional unforeseen costs related to ongoing repairs and replacements or an unsuccessful outcome of any of our pending legal proceedings. See *—We will require significant additional capital to construct and complete certain of our projects, and we may not be able to secure such financing on time with acceptable terms, or at all, which could cause delays in our construction, lead to inadequate liquidity and increase overall costs* and *—Risks Relating to Regulation and Litigation—If we are unsuccessful in any current or potential future arbitration proceedings with customers, the amounts that we are required to pay may be substantial or certain of our post-COD SPAs may be terminated, which may lead to an acceleration of all our debt for the relevant project.*

We currently estimate that the total project costs for the Plaquemines Project will be approximately $23.3 billion to $23.8 billion, including EPC contractor profit and contingency, owners' costs and financing costs, of which approximately $19.8 billion had been paid for as of December 31, 2024. This estimate is based in part on the target cost determined pursuant to the Plaquemines EPC Contracts and reflects increases related to, among other things, inflationary factors and efforts to maintain the project schedule while also reserving additional contingency funds (without giving effect to any commissioning cargo proceeds that may be utilized for project costs). Since FID of Phase 2 of the Plaquemines Project through the date of this Form 10-K, VGLNG has made several incremental equity contributions to VGPL in an aggregate amount equal to approximately $2.8 billion to address such increases in estimated total project costs, and we may be required to make additional incremental equity contributions to the extent total project costs exceed the low-end of the range of estimated total project costs above and that such costs exceed the available project-level debt and equity financing and net proceeds from the sale of commissioning cargos. Pursuant to the Plaquemines Credit Facilities, if such contributions have been utilized to pay project costs for the Plaquemines Project, they are reimbursable by VGPL to VGLNG at our election upon satisfaction of certain conditions under the Plaquemines Construction Term Loan. The costs to achieve completion of the Plaquemines Project may be subject to further increases, which could be material, as a result of many factors outside of our control as described above. As a result, we may need to make additional equity contributions or raise additional project-level equity financing or debt financing in the future to fund any such increase in estimated total project costs that exceed our current contingency, and any such additional contributions or funding could be significant. Further, such cost estimates do not reflect the cost of any potential incremental bolt-on expansion capacity that we may elect to implement in the future.

We currently estimate that the total project costs for the CP2 Project will range from approximately $27.0 billion to $28.0 billion, including EPC contractor profit and contingency, owners' costs and financing costs, substantially all of which have not yet been funded. This estimate is based primarily upon our construction cost experiences with the Calcasieu Project and the Plaquemines Project, the pricing included in the CP2 Phase 1 EPC Contract, and reflect the current inflationary environment as well as the fact that the pipeline for the CP2 Project is expected to be longer and more expensive than the pipelines for the Calcasieu Project and the Plaquemines Project. Our actual costs could vary significantly from our preliminary estimates depending on the terms we may agree to for those contracts. There is no guarantee that we will be able to enter into the necessary contracts to construct the CP2 Project on the same or substantially similar terms as the Calcasieu EPC Contract, the Plaquemines EPC Contracts or the CP2 Phase 1 EPC Contract. As a result, our cost estimates are only an approximation of the actual costs of construction and financing for the CP2 Project. Such cost estimates also do not reflect the cost of any potential incremental bolt-on expansion capacity that we may elect to implement in the future.

Further, the cost reimbursement arrangements under our existing EPC contracts provide that the EPC contractor will be reimbursed for all reimbursable costs incurred in connection with the relevant work, and while the EPC contractor's profit margin will decrease as the amount of cost overrun increases, we are obligated to reimburse the EPC contractor for all reimbursable costs incurred under the EPC contract. However, EPC contracts that we enter into in the future may not include similar cost protections, which could lead to greater cost overruns for our other projects. Any increase in the construction costs for any of our projects could have an adverse impact on our business plan and the viability of the relevant project, and could have a material adverse effect on our current or future business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Our cost estimates with respect to any LNG facilities, related equipment and components, natural gas pipelines, LNG tankers, regasification facilities and other natural gas liquefaction and export facilities (including any expansion of an existing facility) we may decide to develop in the future would be subject to similar uncertainties and potential changes. For example, our cost estimates may continue to increase as we negotiate and finalize agreements with contractors for any such project.

In addition, our cost estimates do not reflect the potential impact of any new tariffs that have been announced or implemented since December 31, 2024 or that may be implemented in the future. Our project budget estimates included in this Form 10-K reflect all tariffs in place, and Section 232 exemptions secured, as of December 31, 2024. Certain of our products are foreign sourced and specified under our regulatory approvals, offering no domestically sourced alternative and potentially exposing us to the effects of any future tariffs that may be imposed. There can be no assurance as to the extent of any future tariffs, or the impact thereof on any of our estimates of total project costs for our projects, which could have a material adverse effect on our construction budgets and limit our growth prospects. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations*—*Liquidity and Capital Resources—Funding Requirements*. Any increases in the construction costs for any of our projects could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Delays in the construction of our projects beyond the estimated development periods could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Our current schedule for the completion of our projects may turn out not to be achievable. For example, our ability to complete our projects on the anticipated schedule is dependent upon our receipt and maintenance of required regulatory approvals and permits and upon various activities being completed by our contractors. Any significant construction or commissioning delay could increase the total cost of the relevant projects and would cause a delay in the completion of the construction of our projects, any of which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

In addition, delays in the construction of our projects beyond the estimated development periods could have a material adverse effect on our contracts. For example, we have experienced unexpected delays in commissioning the Calcasieu Project related to certain necessary repairs and replacements. As a result, we anticipate that COD for the Calcasieu Project will occur on April 15, 2025, which is later than originally forecasted, after significant work related to commissioning, carryover completions, rectification, and certain other items has been completed. Although we are currently generating revenue from sales of LNG commissioning cargos from the Calcasieu Project and the Plaquemines Project prior to commencing commercial operations, we will not generate any revenues or cash flows under our post-COD SPAs (including the Intercompany Excess Capacity SPAs) until we have achieved COD at the project. Additionally, a failure to achieve the project completion date for a project by a date certain may result in an event of default under the related project financing, and, if such debt is accelerated, an event of default under our other financing agreements for that project or otherwise. Any such event of default would entitle the applicable debtholders to exercise certain remedies, including to accelerate the debt obligations under their respective debt instruments and to foreclose against all collateral that secures such debt, representing substantially all assets of the relevant project, which could seriously harm our business and lead to a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects. See —*Risks Relating to Our Indebtedness and Financing—Upon the occurrence of an event of default under our existing and future indebtedness, our lenders and the holders of our debt securities could elect to accelerate all or a portion of our debt. A delay in COD of the Calcasieu Project or Phase 1 or 2 of the Plaquemines Project beyond a certain* *deadline could also result in an event of default under the Calcasieu Pass Credit Facilities or the Plaquemines Credit Facilities, respectively, and/or certain investors exercising step-in rights to control, directly or indirectly, certain of our subsidiaries and the Calcasieu Project.*

Any delay in a project's ability to produce and load LNG for sale or delay in the completion of our projects could cause a delay in the receipt of proceeds projected from sales of LNG commissioning cargos and/or from post-COD SPAs or lead to a loss of one or more customers in the event of significant delays. In particular, each of our post-COD SPAs provides that the counterparty may terminate that SPA in the event that such project has not achieved COD by the relevant deadlines, and such counterparties could also bring claims for contractual damages. See *—Risks Relating to Regulation and Litigation—We are involved and may in the future become involved in disputes and legal proceedings* and *—Risks Relating to Regulation and Litigation—If we are unsuccessful in any current or potential future arbitration proceedings with customers, the amounts that we are required to pay may be substantial or certain of our post-COD SPAs may be terminated, which may lead to an acceleration of all our debt for the relevant project.*

We are dependent on third party vendors and service providers to provide certain services and equipment to our projects.

We rely on third party vendors and service providers to provide certain services, supplies, products and equipment to our projects. We have entered into agreements with these third parties in connection with such services, supplies, products and equipment. However, the ability of our third party vendors and service providers to perform successfully under their agreements is dependent on a number of factors, including their ability to:

- maintain their own financial condition, including adequate working capital, and their ability to pay debt service and other liabilities;
- accurately estimate certain costs;
- meet quality or performance standards for third party equipment;
- procure equipment and supplies;
- execute requisite work and services efficiently; and
- attract, develop and retain skilled personnel.

If any third party vendor or service provider is unable or unwilling to perform according to the terms of its respective agreement for any reason or terminates its agreement, we may need to engage a substitute vendor or service provider. This would likely result in significant project delays and increased costs, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Various economic and political factors, including opposition by environmental or other public interest groups, could negatively affect the timing or overall development, construction and operation of our projects, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Our ability to commence liquefaction operations and produce LNG at our projects (other than the Calcasieu Project and the Plaquemines Project, which commenced production of LNG in January 2022 and December 2024, respectively) or any other natural gas liquefaction and export facility (or expansion of an existing facility) we may decide to develop in the future is dependent on the construction of the relevant facility (or expansion thereof), which will require the expenditure of significant amounts of capital that may exceed our estimates. The development and construction of our projects and any other natural gas liquefaction and export facilities (or expansion of an existing facility) that we may decide to develop in the future takes a number of years and may be delayed by factors such as:

- our ability to obtain or maintain necessary permits, licenses and approvals from regulatory agencies and third parties that are required to construct or operate the relevant project;

- our ability to enter into final ground leases for the relevant project site;
- the identification of any adverse issues with respect to the relevant project site;
- our ability to obtain right-of-way permits, servitudes or other similar property rights necessary to construct the pipelines required to interconnect the relevant project site with natural gas suppliers;
- our ability to administer our existing EPC Contracts and to successfully negotiate definitive agreements with EPC contractors for Phase 2 of the CP2 Project, the CP3 Project, the Delta Project and any future projects and expansions thereof we develop, as well as with other advisors, contractors and consultants necessary for the development and construction of the relevant project in a timely manner for each of our projects;
- our ability to maintain or secure definitive post-COD SPAs for an adequate portion of the expected nameplate capacity of the CP2 Project, the CP3 Project, the Delta Project or any future projects, and phases or expansions thereof, we develop to support an FID for each such project;
- our ability to secure necessary additional capital or financing on satisfactory terms, or at all, to develop the CP2 Project, the CP3 Project and the Delta Project and any future projects and expansions thereof;
- the discovery of environmental conditions on the relevant project site that require investigation, remediation or other changes to the relevant project;
- failure by our contractors to fulfill their obligations under their contracts relating to the development and construction of the relevant project, or disagreements with them over their contractual obligations;
- as construction progresses, we may decide or be forced to submit change orders to our contractors that could result in longer construction periods and higher than anticipated construction expenses;
- *force majeure* events, natural or man-made disasters, terrorist attacks or sabotage;
- shortages of materials or delays in the delivery of materials;
- weather conditions and impacts from potential climate change, hurricanes, severe weather events and other catastrophes, such as explosions, fires, floods and accidents;
- local and general economic and infrastructure conditions;
- political unrest or local community resistance or resistance by environmental groups and other advocates or impacts to indigenous peoples or impact by indigenous people to the development of the relevant project due to health, safety, environmental, or security or other concerns;
- our ability to attract sufficient skilled and unskilled labor, the existence of any labor disputes, our ability to maintain good relationships with our contractors in order to construct the relevant project within the expected parameters and the ability of those contractors to perform their obligations;
- economic downturns, increases in interest rates or other events that may affect the availability of sufficient financing for LNG projects on commercially reasonable terms;
- decreases in the price of LNG, which might decrease the expected returns relating to investments in LNG projects; and
- other risks inherent to the construction, expansion and operation of LNG facilities and other natural gas liquefaction and export facilities.

Many of these factors are outside of our control.

More generally, the regulatory approval process for many LNG and natural gas infrastructure projects has become increasingly slower and more difficult, due in part to federal, state and local concerns related to natural gas exploration and production, pipeline activities and associated environmental impacts, and increased opposition to the natural gas industry and related infrastructure. Furthermore, regulatory approvals and authorizations, even when obtained, have increasingly been subject to judicial challenge by activists requesting that issued approvals and authorizations be stayed, reversed, and vacated. Increased opposition and regulatory challenges may harm our ability to obtain and maintain necessary regulatory approvals. For example, on November 27, 2024, in response to project opponents challenging FERC's authorization for the CP2 Project, FERC issued an order on rehearing that generally rejected the arguments opposing the CP2 Project and noted that it remains confident in the authorization order, but decided to partially "set aside" its prior analysis to initiate a supplemental environmental review of certain discrete potential impacts of the project. As a result, FERC stated that it will not issue authorizations to proceed with construction until FERC issues a further merits order. On February 7, 2025, FERC staff issued a draft supplemental environmental review that concluded that these potential impacts were not significant, which is subject to public comment until March 31, 2025. The opponents of the CP2 Project have also appealed the initial FERC authorization of the CP2 Project to the U.S. Court of Appeals for the D.C. Circuit. In response to FERC's order on rehearing, the D.C. Circuit on December 13, 2024, granted an unopposed motion by FERC to hold the appeal in abeyance, which will delay briefing of the D.C. Circuit appeal. There can be no assurance as to the outcome of such proceedings.

There can be no assurance that our existing or future regulatory approvals will not be subject to other legal challenges, or that such approvals will not be re-examined vacated, withdrawn, overturned, altered or otherwise modified in a manner adverse to the development, construction or operation of one or more of our projects or to our business more generally. If we are required to modify our activities as a result of any changes to our existing regulatory approvals, the impact could increase our project costs, delay our project timelines, affect our ability to complete our planned projects, or result in claims from third parties if we are unable to meet our commitments under our pre-existing commercial agreements, all of which could have a material adverse effect on our business. Any delay in completion of our projects that prevents us from producing and loading LNG when anticipated would also cause a delay in the receipt of revenues therefrom, potentially require us to pay damages to selected customers with whom we have entered into definitive SPAs, or, in the event of significant delays beyond certain time periods, permit customers to terminate their contractual obligations to us.

In addition, the successful completion of our projects is subject to the risk of cost overruns, schedule delays, weather disruptions, labor disputes and other factors, any of which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Our business could be materially and adversely affected if we do not secure the right or if we lose the right to situate certain lateral pipelines, longer-haul pipelines or any other pipeline infrastructure for any of our projects on property owned by third parties, or if we do not complete the construction of those pipelines in a timely fashion.

We expect to obtain access to the natural gas required for the operation and commissioning process for our projects through certain lateral and longer-haul pipeline connections that we plan to construct as part of those projects, each of which will connect the relevant LNG facility to one or more third-party pipelines. While the lateral pipelines for both the Calcasieu Project and the Plaquemines Project are complete, much of this contemplated pipeline infrastructure has not been completed. As we are expanding our development footprint with the CP2 Project, the CP3 Project, the Delta Project and the potential bolt-on expansion for the Plaquemines Project, these projects' production capacities will require natural gas volumes that necessitate the construction of longer interstate and intrastate pipelines that provide incremental access and delivery capability from the Permian, Haynesville, Western Haynesville, Eagle Ford, mid-continent shale, and other formations. At their expected peak production capacity, we expect these three development stage projects will require approximately 4.3, 6.5 and 5.3 bcf/d of gas supply, respectively. We plan to construct significant 48 inch compressed pipeline infrastructure, both independently and in partnership with certain qualified third parties, sufficient to source the required natural gas for these projects from primarily the Permian, Haynesville and Western Haynesville shale plays. Timely completion of such pipelines will be subject to numerous risks, such as interface risks with our third-party partners, weather delays, accidents, inability to obtain required rights-of-way and servitudes, and regulatory approvals.

We do not expect to own or lease the vast majority of the tracts of land on which we expect to construct the pipeline infrastructure that will connect our projects to third-party pipelines and other sources of natural gas. As a result, we need to secure servitudes, rights-of-way and similar rights necessary for the construction of that pipeline infrastructure. Although we have obtained permanent servitudes in respect of all of the land on the TransCameron Pipeline route for the Calcasieu Project and the Gator Express Pipeline route for the Plaquemines Project, certain tracts in respect of which we have obtained such rights are currently burdened by mortgages that would be superior to our rights. While the servitudes we obtain generally contain clauses that require the relevant landowners to use commercially reasonable efforts to provide us with subordination, non-disturbance and attornment agreements, or the SNDAs, if we request them, there can be no assurance that any such SNDAs, or any other measures we take, will result in us having adequate real property rights with respect to these tracts. Moreover, with respect to the other pipelines that we plan to develop, we have not yet obtained all of the rights necessary to construct the pipeline infrastructure expected to connect those projects to third-party pipelines and other sources of natural gas, and there can be no assurance that we will be able to obtain the necessary property rights on terms satisfactory to us, or at all.

As a result of these factors, our pipeline infrastructure for the CP2 Project, the CP3 Project, the Delta Project and the potential bolt-on expansion for the Plaquemines Project is subject to the possibility of increased costs to obtain necessary land use rights. If we were unable to obtain those rights or if we were to lose any such rights with respect to a project, or if we were required to relocate any of our pipeline infrastructure, our business could be materially and adversely affected.

There is no assurance that our projects will receive the local government and community support required for construction.

The development and construction of our projects requires support and approval from local governments with jurisdiction over the project sites and support from the communities in which they are located. While we believe we have requisite local government and community support in Cameron Parish and Plaquemines Parish, where our projects our located, there is no assurance that we can maintain such support or that we will receive such support for other projects, including any expansions thereof, we may develop in the future. Any failure to obtain or maintain the requisite local government and community support for our projects, or for any other natural gas liquefaction and export facility we may decide to develop in the future, could have a material adverse effect on our ability to develop and construct that project on our anticipated schedule, or at all.

Our real property rights in the sites for our projects or any other natural gas liquefaction and export facilities that we may decide to develop in the future may be adversely affected by the rights of others that are superior to those of the grantors of our real property rights.

The Calcasieu Project, the Plaquemines Project, the CP2 Project, the CP3 Project, the Delta Project, any potential bolt-on expansion, any other natural gas liquefaction and export facilities (including any expansion of such facilities), and pipeline development projects that we may decide to develop in the future are likely to be located on land subject to long-term servitudes, leases, rights of way and similar agreements with landowners. The ownership interests in the land subject to these servitudes, leases, rights-of-way and similar agreements may be subject to mortgages securing loans or other liens (such as tax liens) and other servitudes, lease rights and rights-of-way of third parties that were created prior to our servitudes, leases and rights-of-way. As a result, certain of our rights under these servitudes, leases or rights-of-way may be subject, and subordinate, to the rights of those third parties.

We perform title searches, obtain title insurance and enter into non-disturbance agreements to protect ourselves against these risks. Such measures may, however, be inadequate to protect our operating projects against all risk of loss or impairment of our rights to use the land on which the Calcasieu Project, the Plaquemines Project, the CP2 Project, the CP3 Project, the Delta Project, any potential bolt-on expansion or any future natural gas liquefaction and export facilities we may decide to develop are located.

Any such loss or curtailment of our rights to use the land on which our projects or any other future project is located, and any increase in rent due on such lands, could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects and could also adversely affect our ability to secure necessary additional capital for the relevant project.

The natural gas liquefaction system and mid-scale design we utilize at our projects are the first of such sized modules developed by us and Baker Hughes, and there can be no assurance that these modules, or our projects, will achieve the level of performance or other benefits that we anticipate over the long term.

We are constructing our projects using a natural gas liquefaction system provided by Baker Hughes that is deployed in a unique mid-scale, factory-built configuration that we developed. While Baker Hughes has developed liquefaction systems utilizing both larger and smaller modules before, the specific liquefaction modules that we are using are the first of such sized modules produced by Baker Hughes, and accordingly the configuration, production, transportation, installation and commissioning of such sized modules has not yet been tested in LNG projects, except for the Calcasieu Project and the Plaquemines Project. As a result, there may be issues with respect to this design that have not yet been identified, notwithstanding the current production of LNG at the Calcasieu Project and the Plaquemines Project, that could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects. While Baker Hughes has an obligation to ensure the liquefaction systems meet minimum performance guarantees, there can be no assurance that the liquefaction system is able to satisfy the minimum performance guarantees or maintain such performance guarantees throughout the operating life of a facility.

We have the right under the Baker Hughes Master Agreement to require Baker Hughes to enter into a long-term service agreement on specified terms with respect to long term maintenance, repair, and servicing of the liquefaction, power, and booster compressor equipment it supplies. While we have entered into a long-term service agreement with Baker Hughes for the Calcasieu Project and the Plaquemines Project, under which Baker Hughes guarantees the minimum performance and operating availability of certain liquefaction and power systems it supplies, we have not yet negotiated the final terms for any such long-term service agreement for any other projects. Notwithstanding our rights under the Baker Hughes Master Agreement, there can be no assurance that we will enter into the long-term service agreement with Baker Hughes on the same terms as we currently anticipate. If we encounter issues with the new technology, including, for example, higher operating or maintenance expenses, lower performance standards or more downtime than we currently anticipate, our projects may not be able to produce the quantity or volume of LNG we anticipate and our projects may be delayed and the financial viability of our projects may be adversely impacted. Any of these factors could have a material adverse effect on our business, financial condition, operating results, liquidity and prospects.

The phased commissioning start-up of our projects will subject us to additional risks.

The unique configuration of our LNG projects necessitates a phased commissioning start-up process for each of our projects (and phases thereof) that will generally result in a longer commissioning process. The length of any commissioning process depends on a number of factors related to equipment performance and the ability to establish reliable and safe operations for that equipment and the facility as a whole. For example, once we have sufficient power to operate the first pre-treatment unit, and the first LNG storage tank and first gas pre-treatment unit have been installed for a particular project, we generally begin the commissioning start-up of the relevant equipment on a phased basis. This sequential commissioning of the liquefaction blocks, power island system, pre-treatment system, and other equipment for a project is subject to several risks, some of which may be unknown to us.

For example, the simultaneous construction of a particular LNG facility and production of LNG at that facility could subject us and our third-party contractors to additional safety hazards, as well as additional costs related to the management of those safety hazards during the phased commissioning start-up of a facility. To successfully implement our phased commissioning start-up, our EPC contractors will be required to develop and implement a safe work plan. Furthermore, we will require additional regulatory approvals from FERC, including approval of our EPC contractor's safe work plan, in order to implement our phased commissioning start-up at a facility before construction has been completed. Any delays in implementing any of the measures required for the phased start-up of our facilities or in obtaining any necessary regulatory approvals, and any additional costs associated with the phased start-up of our facilities, could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

We are and will be relying on third-party engineers to estimate the future capacity ratings and performance capabilities of our projects, and these estimates may prove to be inaccurate.

We are and will be relying on third parties, principally the construction contractors, for the design and engineering services underlying our estimates of the future capacity ratings and performance capabilities of our projects. If any of our liquefaction facilities for our projects, when completed, fails to have the capacity ratings and performance capabilities that we intend, the estimates set forth in this Form 10-K may not be accurate. Failure of any of our liquefaction facilities for our projects to achieve our intended capacity ratings and performance capabilities could prevent us from satisfying the performance tests required in order to achieve COD start dates under our post-COD SPAs and cause the quantity of LNG we produce to fall short of our contractual delivery obligations to customers and could have a material adverse effect on our business, contracts, operating results, financial condition, cash flow, liquidity, financing requirements and prospects. Further, we will not generate any revenues or cash flows under our post-COD SPAs (including the Calcasieu Foundation SPAs) or from sales to third parties of excess capacity covered by the Intercompany Excess Capacity SPAs, in each case until we have achieved COD for the relevant project.

Additionally, a failure to achieve the project completion date for a project by a date certain may result in an event of default under the related project financing, and, if such debt is accelerated, an event of default under our other financing agreements for that project or otherwise. Further, under certain financing agreements we may be required to (i) maintain in effect all material project agreements, including the relevant EPC contract, for a particular project and (ii) comply in all material respects with their payment and other material obligations under the material project agreements for such project, and any breach of such requirements may, after any applicable cure periods, result in an event of default under our other financing agreements for that project or otherwise. Any such event of default would entitle the applicable debtholders to exercise certain remedies, including to accelerate the debt obligations under their respective debt instruments. See *—Delays in the construction of our projects beyond the estimated development periods could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.*

Construction and operations of natural gas pipelines and lateral pipeline connections for our projects are subject to a number of regulatory approvals, development risks, operational hazards and other risks, which could cause cost overruns and delays and could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

We have completed the construction of two of our natural gas pipeline projects, the TransCameron Pipeline and the Gator Express Pipeline. Construction and operations of our future, planned natural gas pipelines and pipeline connections for our projects, including the CP Express natural gas pipeline, the pipeline required for the CP3 Project and the Delta Express natural gas pipeline, are subject to the risks of delay or cost overruns inherent in any construction project resulting from numerous factors, including, but not limited to, the following:

- failure to obtain and maintain relevant approvals and permits from governmental and regulatory agencies;
- difficulties or delays in obtaining, or failure to obtain, sufficient equity or debt financing on reasonable terms;
- difficulties in engaging qualified contractors necessary for the construction of natural gas pipelines and lateral pipeline connections for any of our projects;
- shortages of equipment, material or skilled labor;
- natural disasters and catastrophes, such as hurricanes, explosions, fires, floods, industrial accidents and terrorism;
- unscheduled delays in the delivery of ordered materials;
- EPC productivity factor realization, work stoppages and labor disputes;
- difficulties or delays in obtaining, or failure to obtain, sufficient real property interests on which to construct and locate the pipelines and associated facilities;

- unexpected or unanticipated need for additional improvements;
- unexpected additional material quantities and labor hours; and
- adverse general economic conditions.

Delays beyond the estimated development periods, as well as cost overruns, could increase the cost of completion beyond the amounts that are currently estimated, which could require us to obtain additional sources of financing to fund the activities. Any delay in completion of the pipelines may also cause a delay in commencement of commercial operations of our projects even if the projects are substantially complete for commercial operations. As a result, any significant construction delay in construction of the natural gas pipelines and lateral pipeline connections, whatever the cause, could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

If third-party pipelines and other facilities interconnected to our pipelines and facilities are or become unavailable to transport natural gas or if there are any reductions in the capacity of, or the allocations to, interconnecting third-party pipelines, this could cause a reduction of volumes transported to our facilities and could have a material adverse effect on our business, financial condition, operating results, liquidity and prospects.

We depend and will continue to depend upon third-party pipelines and other facilities interconnecting with our projects to provide material gas delivery options to our liquefaction and export facilities. We have entered into multiple agreements with various pipelines for the transport of natural gas to the Calcasieu Project and the Plaquemines Project. The transport of natural gas to the Calcasieu Project and the Plaquemines Project has been secured through a portfolio of approximately 20-year transportation arrangements. The CP2 Project has also entered into agreements for substantial firm transportation capacity with third parties and CP Express. We are also in the process of contracting for, or developing, the required transportation capacity in support of such projects as well as for our other projects. We do not have any control over the operation, development, expansion or maintenance of these third-party pipelines or certain other third-party pipeline facilities that may be interconnected with our projects in the future.

The design, construction and operation of natural gas pipelines are highly regulated activities. Approvals of FERC under Section 7 of the NGA, as well as several other material governmental and regulatory approvals and permits, are required in order to construct and operate an interstate natural gas pipeline, and those approvals may be subject to judicial appeals. Neither we nor our SPA customers have any control over the ability of third-party pipelines to obtain, maintain or comply with any such regulatory approvals and permits.

Additionally, the capacity on interconnecting pipelines may not be sufficient to accommodate additional liquefaction trains we may construct if we undertake an expansion of our project facilities, including the potential bolt-on expansion for the Plaquemines Project. Further, if we need to replace one or more of our interconnection agreements or enter into additional agreements, we may not be able to do so on commercially reasonable terms or at all.

If we are unable to secure any necessary pipeline interconnections, or if any third-party pipelines or pipeline connections that we currently depend upon were otherwise to become unavailable for current or future volumes of natural gas due to a failure to obtain or maintain regulatory approvals or permits, repairs, damage to the facility, lack of capacity or any other reason, our ability to continue shipping natural gas from producing regions to our projects could be restricted, which could have a material adverse effect on our business and operations, and on our ability to perform under the SPAs.

Delays in deliveries of newbuild or acquired LNG tankers, and increases in price or building costs, could harm our operating results.

The delivery of newbuild LNG tankers to us could be delayed, not completed or cancelled, which would delay or eliminate our ability to optimize contracts with spot and term customers seeking delivered LNG. The relevant shipbuilder or third-party seller could fail to deliver the newbuild LNG tankers or the relevant shipbuilding contract or acquisition agreement could be cancelled if the shipbuilder, the seller or we have not met certain obligations, including the failure to pay any remaining amounts required under such agreements. In addition, third-parties from whom we may charter LNG tankers may fail to deliver such LNG tankers to us, or such deliveries could be delayed. If delivery of any newbuild LNG tankers currently contracted to be acquired, or any LNG tanker we contract to charter on a third-party basis, or acquire or charter in the future, is materially delayed, it could adversely impact our business and we may not be able to realize the anticipated benefits of operating our LNG tanker fleet.

Our receipt of newbuild LNG tankers could be delayed, cancelled or otherwise not completed because of, among other things, quality or engineering problems or failure to deliver the LNG tanker in accordance with the specifications, changes in governmental regulations or maritime self-regulatory organization standards, delays to delivery of equipment by third-party suppliers, work stoppages or other labor disturbances at the shipyard, bankruptcy or other financial or liquidity problems of the shipbuilder, a backlog of orders at the shipyard, political or economic disturbances in the country or region where the vessel is being built, weather interference or catastrophic events, shortages of or delays in the receipt of necessary construction materials, such as steel, and our inability to finance the purchase of the LNG tanker.

In addition, the contracts for newly built vessels subject us to counterparty risk. The ability and willingness of each of our counterparties to perform its obligations under a contract with us will depend on a number of factors that are beyond our control, including, among other things, general economic conditions, the condition of the LNG shipping industry, the overall financial condition of our counterparty, prevailing prices for LNG cargos, rates received for specific types of LNG tankers, and various expenses. If our counterparties fail to meet their obligations to us or attempt to renegotiate our agreements, if our counterparties fail to deliver an LNG tanker in accordance with the terms of the relevant contract, or if a counterparty otherwise fails to honor its obligations to us under a contract, we could sustain significant losses, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Additionally, the final cost of the LNG tankers we have contracted to acquire could increase, pursuant to adjustment provisions included in the respective contracts. We may decide to raise additional capital to fund our remaining payment commitments pursuant to such contracts. Our ability to obtain financing that may be used to provide additional funding to cover all of the costs for our LNG tankers will depend, in part, on factors beyond our control. Accordingly, we may not be able to obtain financing on terms that are acceptable to us, or at all, which could impact our ability to make payments under our contracts to acquire LNG tankers when due. Any failure to make payments under any existing or future contracts to acquire LNG tankers could cause delays in the delivery of our newbuild LNG tankers or could result in an event of default under our contracts for the acquisition of LNG tankers. In addition, if we are unable to make any payments under our existing contracts to acquire LNG tankers when due, we may lose our rights to acquire such LNG tankers as well as our right to be refunded certain amounts already paid pursuant to the applicable contracts.

Delays in the delivery, or shortfalls in the construction and acquisition of, our LNG tanker fleet, could require us to charter or subcharter third-party LNG tankers, which could expose us to additional liability and could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Management and operation of our LNG tanker fleet and the subcharter of third-party vessels will involve significant risks.

Through certain wholly-owned subsidiaries, in addition to the two newbuild LNG tankers that have been delivered already, we have entered into contracts to acquire seven additional LNG tankers that are currently under construction and will be delivered on a rolling basis in 2025 and 2026, which will be used to provide additional optionality to short-, medium- or long-term customers and to service our single existing post-COD DPU SPA and any future SPAs where LNG is sold on a delivered basis. Following delivery of each of these LNG tankers, we plan to manage and operate such tankers through our subsidiaries. In addition, we have chartered, and anticipate that we will continue to charter, LNG tankers to supplement our wholly-owned fleet. We are in the process of building out our team to manage and operate our fleet of LNG tankers, and as a result we will be exposed to various new operational risks as we expand that team and grow our fleet of LNG tankers. We will also be exposed to operational risks where we subcharter third-party vessels. For example, we will be exposed to the following risks with respect to the operation of LNG tankers:

- the Company's limited track record with managing and operating our own LNG tanker fleet;
- performing below expected levels of efficiency or capacity or required changes to specifications for continued operations;
- breakdowns or failures of equipment or shortages or delays in the delivery of supplies;
- risks related to operators and service providers of tanker or tugs used in our operations;
- operational errors by us or any contracted facility, port or other operator of related infrastructure.
- failure to maintain the required government or regulatory approvals, permits or other authorizations;
- accidents, fires, explosions or other events or catastrophes;
- a lack of adequate and qualified personnel to adequately crew and operate the LNG tankers;
- potential labor shortages, work stoppages or labor union disputes;
- our potential inability to recruit and retain a team to manage and operate our fleet of LNG tankers and any subchartered third-party vessels;
- weather-related or natural disaster interruptions of operations;
- pollution, release of or exposure to toxic substances or environmental contamination, including marine accidents and spills, affecting operations;
- inability, or failure, of any counterparty to any fleet-related agreements to perform their contractual obligations;
- a lack of demand for shipping services by our customers after we receive delivery of our LNG tankers or subcharter a third-party vessel;
- failures to supply due to scheduled or unscheduled maintenance; and
- potential changes to cabotage laws which may affect the ability of our LNG tankers and subchartered third-party vessels to engage in coastwise trade.

As a result, in addition to our current operational risks, we will be subject to risks related to the operation of LNG tankers, which operations are complex and technically challenging and subject to mechanical risks and problems. In particular, marine LNG operations are subject to a variety of risks, including, among others, marine disasters, piracy, bad weather, mechanical failures, environmental accidents, epidemics, grounding, fire, explosions and collisions, human error, and war and terrorism. An accident involving our cargos or any of our LNG tankers or subchartered third-party vessels could result in death or injury to persons, loss of property or environmental damage; delays in the delivery of cargo; loss of revenues; governmental fines, penalties or restrictions on conducting business; higher insurance rates; and damage to our reputation and customer relationships generally. Any of these circumstances or events could increase our costs or lower our revenues.

If our LNG tankers, or any vessels we subcharter, suffer damage as a result of such an incident, they may need to be repaired. Repairs and maintenance costs for LNG tankers are difficult to predict and may result in higher than anticipated operating expenses or require additional capital expenditures. The loss of earnings or costs to subcharter replacement tankers while these LNG tankers are being repaired could have a material adverse effect on our current or future business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

If one of our LNG tankers, or any vessels we subcharter, were involved in an accident with the potential risk of environmental impacts or contamination, the resulting media coverage and potential liability, including regulatory penalties, sanctions, fines and litigation, could have a material adverse effect on our reputation, our current or future business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects. An accident involving one of our LNG tankers would also distract our management team. We expect our offshore operating expenses to depend on a variety of factors including crew costs, provisions, deck and engine stores and spares, lubricating oil, insurance, maintenance and repairs and shipyard costs, many of which are beyond our control. Other factors, such as increased cost of qualified and experienced seafaring crew and changes in regulatory requirements, could also increase operating expenditures.

If we fall short of our goals in acquiring, building or maintaining our LNG tanker fleet, we may be required to subcharter vessels from third parties. Additionally, our ability to subcharter vessels from third parties could be affected by potential shortages of LNG tankers worldwide. See *—Risks Relating to the LNG Industry—There may be shortages of LNG tankers worldwide, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.* As the overall trends steer toward more regulation and more stringent operating requirements, we are subject to the risk that subchartered vessels we employ could fall out of compliance with such regulations. The terms of any charter agreement into which we may enter to substitute for shortfalls in our own LNG tanker fleet may require that we bear some or all of the associated costs with maintaining compliance with such regulations. While we believe we are appropriately situated to minimize this risk given the building of our own LNG tanker fleet, we cannot assure you that such factors will not have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Future occurrences of any of the foregoing or any other events of a similar or dissimilar nature could have a material adverse impact on our business, financial condition and results of operations.

The construction of our projects, and our operations, are subject to significant hazards and uninsured risks, one or more of which may create significant liabilities and losses for us.

The construction and operation of our projects is and will be subject to the inherent risks associated with these types of operations, including the following:

- explosions, pollution, releases of toxic substances;
- fires, hurricanes and adverse weather conditions and other weather-related interruptions of construction and/or operations;
- facilities performing below expected levels of efficiency;
- breakdown, failures or mechanical issues affecting our equipment;
- operational errors by vessel or tug operators;
- operational errors by us or any contracted facility operator; and
- labor disputes.

The occurrence of any of these events could require us, or enable our counterparties, to declare a *force majeure* under our material construction contracts or other construction contracts or SPAs or otherwise could result in significant delays in commencement or interruptions of operations and/or in damage to or destruction of our facilities or damage to persons and property. In addition, our operations and the facilities and vessels of third parties on which our operations are dependent face possible risks associated with acts of aggression or terrorism.

We do not, nor do we intend to, maintain insurance against all of these risks and losses. We may not be able to maintain desired or required insurance in the future at rates that we consider reasonable. The occurrence of a significant event not fully insured or indemnified against could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

We may enter into certain arrangements to share the use and operations of facilities among projects, which would require us to meet certain conditions under our project-level financing documents. Despite the protection provided by such financing documents, the nature of such sharing arrangements is not currently known and may limit our operational flexibility, use of land and/or facilities.

We are permitted under certain of our project-level financing documents to enter into sharing arrangements with one or more entities that are developing or own one or more liquefaction trains and related facilities among our various projects. Such sharing arrangements may involve sharing the use and capacity of land and facilities with such adjacent project owners, including pooling the capacity of liquefaction trains, sharing common facilities, such as power generating facilities, storage tanks and berths, and sharing capacity of the pipeline interconnections, to the extent permitted under the relevant financing documents. We may also, subject to regulatory approvals, transfer and/or amend previously obtained permits and other authorizations or applications such that they may be used by such other project owners with which we may have sharing arrangements.

As future arrangements that would only be fully determined if the circumstances arise, there is uncertainty as to the full scope and impact of these sharing arrangements. Our project-level financing documents require us to meet certain conditions in respect of such sharing arrangements. These sharing arrangements would be subject to quiet enjoyment rights for the relevant project owners.

Risks Relating to the LNG Industry

Competition in the LNG industry is intense, and certain of our competitors may have greater financial, engineering, marketing and other resources than we have.

We operate in the highly competitive area of LNG production, and we face intense competition from independent, technology-driven companies, national oil companies and major independent oil and natural gas companies and utilities. Certain of our competitors may have financial, engineering, marketing and other resources substantially greater than we have, and some of them are fully integrated oil and gas companies. Certain of these competitors also have longer operating histories, more development experience, greater name recognition, larger staffs, greater access to natural gas and LNG supply, and substantially greater financial, engineering, marketing and other resources than we do. In some cases, they may have also fully recouped the development and construction costs of their facilities. Our competitors' superior resources or financial position could allow them to compete successfully against us, including by increasing their LNG production, decreasing their LNG prices, offering LNG transportation or otherwise. Our ability to compete in this highly competitive environment will depend in part upon our ability to successfully develop, construct and operate our projects, including any bolt-on expansions thereof, and any other natural gas liquefaction and export facilities that we may develop in the future, and our ability to enter into SPAs or otherwise sell LNG. Increases in the production of LNG by our competitors, or decreases in their LNG prices, could have a material adverse effect on the viability of any of our planned projects and on our ability to compete with them successfully. If we are unable to compete successfully with these companies, our business, financial condition and results of operations could be adversely affected.

We face competition based upon the international market price for LNG.

Our projects are and will be subject to the risk of LNG price competition at times when we need to replace any existing post-COD SPA, whether due to natural expiration, default or otherwise, and at times when we seek to sell or enter into additional SPAs with respect to our respective projects' commissioning cargos and LNG that is produced in excess of the volumes required under our existing SPAs. Factors relating to competition may prevent us from entering into a new or replacement post-COD SPA on economically comparable terms as existing post-COD SPAs, or at all. Such an event could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects. Factors which may negatively affect potential demand for LNG from our projects and any other natural gas liquefaction and export facilities that we may decide to develop in the future are diverse and include, among others:

- increases in worldwide LNG production capacity and availability of LNG for market supply;

- lower than expected global economic growth and decreased demand for energy, including LNG, or increases in demand for LNG but at levels below those required to maintain a price equilibrium with respect to the cost of supply;
- increases in the cost to supply natural gas feedstock to our projects;
- decreases in the cost of competing sources of natural gas or alternate fuels such as coal, heavy fuel oil and diesel;
- decreases in the price of non-U.S. LNG, including decreases in price as a result of contracts indexed to lower oil prices;
- increases in capacity and utilization of nuclear power, renewable power, and related facilities outside the United States;
- political instability in foreign countries that import LNG, increased tariffs, or strained relations between such countries and the United States;
- displacement of LNG by new discoveries of gas, pipeline natural gas or alternate fuels in locations where access to these energy sources is not currently available; and
- any events, developments or public statements, including by competitors or customers, that adversely impact our reputation.

Failure of LNG exported from the United States, including from our projects, to remain a competitive source of energy for international markets could adversely affect the LNG business of our customers, which could have a material adverse effect on their ability and willingness to perform under their post-COD SPAs with us or otherwise contract with us, and on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Operations at our projects will be dependent upon the ability of our customers to deliver LNG supplies from the United States, including our projects, which is primarily dependent upon LNG being a competitive source of energy internationally. The success of our business plan and the commercial operations of our projects, or any other natural gas liquefaction and export facility that we may decide to develop in the future, is dependent, in part, on the extent to which LNG can, for significant periods and in significant volumes, be supplied from North America and delivered to international markets at a lower cost than the cost of alternative energy sources. Through the use of improved exploration technologies, additional sources of natural gas may be discovered outside the United States, which could increase the available supply of natural gas outside the United States and could result in natural gas in those markets being available at a lower cost than LNG exported to those markets.

Political instability in foreign countries that import or export natural gas, increased tariffs, or strained relations between such countries and the United States, may also impede the willingness or ability of LNG purchasers or suppliers and merchants in such countries to import LNG from the United States. Furthermore, some foreign purchasers or suppliers of LNG may have economic or other reasons to obtain their LNG from, or direct their LNG to, non-U.S. markets or from or to our competitors' liquefaction facilities in the United States. Conversely, future policy change in laws or regulation in the United States could restrict or limit natural gas exports to certain countries or in general.

In addition to natural gas, LNG also competes with other sources of energy, including coal, oil, nuclear, hydroelectric, wind and solar energy. LNG from our projects also competes with other sources of LNG, including LNG that is priced to indices other than Henry Hub. Some of these sources of energy may be available at a lower cost than LNG from our projects in certain markets. The cost of LNG supplies from the United States, including our projects, may also be impacted by an increase in natural gas prices in the United States. Although our customers may elect not to incur these costs by not lifting or electing not to take delivery of certain scheduled LNG cargos, they are obligated to pay the fixed facility charge under the relevant SPA for their scheduled quantities. However, such commercial conditions could cause customers to seek alternatives to satisfying this obligation under their SPAs.

As a result of these and other factors, LNG may not be a competitive source of energy internationally. The failure of LNG to be a competitive supply alternative to local natural gas, oil and other alternative energy sources in markets accessible to our customers could adversely affect the ability of our customers to deliver LNG from the United States or from our projects on a commercial basis, which could have a material adverse effect on their ability and willingness to perform under their post-COD SPAs with us or contract with us with respect to the sales of our commissioning cargos or the excess capacity covered by the Intercompany Excess Capacity SPAs. Furthermore, any such significant impediment to our customers' ability or willingness to deliver LNG from the United States generally, or from our projects specifically, could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Cyclical or other changes in the demand for and price of LNG and natural gas may adversely affect our business and the performance of our customers and could have a material adverse effect on our business, contracts, financial condition, operating results, cash flows, liquidity and prospects.

Our LNG business and the development of domestic LNG facilities and projects generally is based on assumptions about the future availability and price of natural gas and LNG, and the prospects for international natural gas and LNG markets. In particular, changes in the price of natural gas that is supplied to our projects or any other natural gas liquefaction and export facility we may decide to develop in the future could affect the demand for, and price of, the LNG that our projects are expected to produce. Changes in the price of natural gas could also affect the competitiveness of LNG as a source of energy, which could adversely affect our customers or the demand for, and price of, LNG. Any of these factors could, in turn, affect the viability of natural gas liquefaction and export facilities such as those we are proposing to construct, and could require us to re-evaluate the viability of any of our planned projects and result in us postponing or abandoning our current plans for development of our projects. Natural gas and LNG prices have been, and are likely to continue to be, volatile and subject to wide fluctuations in response to one or more of the following factors:

- competitive liquefaction capacity in North America;
- insufficient or oversupply of natural gas liquefaction or receiving capacity worldwide;
- insufficient LNG tanker capacity;
- weather conditions, including temperature volatility resulting from changes in climate, and severe weather events may lead to unexpected distortion in the balance of international LNG supply and demand;
- reduced demand and lower prices for natural gas;
- the extent of domestic production and importation of natural gas in relevant markets;
- increased natural gas production deliverable by pipelines, which could suppress demand for LNG;
- decreased oil and natural gas exploration activities, which may decrease the production of natural gas, including as a result of any potential ban on production of natural gas through hydraulic fracturing;
- cost improvements that allow competitors to provide natural gas liquefaction capabilities at reduced prices;
- changes in supplies of, and prices for, alternative energy sources such as coal, oil, nuclear, hydroelectric, wind and solar energy, which may reduce the demand for natural gas;
- changes in regulatory, tax, environmental or other governmental policies (including tariffs) regarding imported or exported LNG, natural gas or alternative energy sources, which may reduce the demand for imported or exported LNG and/or natural gas;
- political conditions in natural gas producing regions, including geopolitical events such as the Russia-Ukraine conflict and the conflicts occurring in the Middle East;
- sudden decreases in demand for LNG as a result of natural disasters or public health crises, including the occurrence of a pandemic, and other catastrophic events;
- adverse relative demand for LNG compared to other markets, which may decrease LNG exports from North America; and

- cyclical trends in general business and economic conditions that cause changes in the demand for natural gas.

We may be forced to delay some of our capital projects and our customers, who may be in financial distress, may slow down decision-making, delay planned projects or seek to renegotiate or terminate agreements with us. To the extent any of our counterparties is successful in any such renegotiation or termination, we may not be able to obtain new contract terms that are favorable to us or to replace contracts that are terminated. Counterparties may also be forced to file for bankruptcy protection, in which case our existing contracts with those counterparties may be rejected by the bankruptcy court.

Adverse trends or developments affecting any of these factors above could result in decreases in the price of LNG and/or natural gas, which could adversely affect the LNG business of our customers and the viability of our projects, and could also adversely affect the demand for, and price of, LNG, any of which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

There may be shortages of LNG tankers worldwide, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

The construction and delivery of LNG tankers require significant capital and long construction lead times, and the availability of the tankers (including the tankers that we have contracted to acquire) could be delayed to the detriment of our LNG business and our customers, and therefore our business, because of:

- an inadequate number of shipyards constructing LNG tankers and a backlog of orders at these shipyards;
- political or economic disturbances in the countries where the vessels are being constructed;
- acts of war or piracy;
- changes in governmental regulations or maritime self-regulatory organizations;
- work stoppages or other labor disturbances at the shipyards;
- bankruptcy or other financial crisis of shipbuilders or shipowners;
- quality or engineering problems;
- disruptions to maritime transportation routes;
- weather interference or a catastrophic event, such as a major earthquake, tsunami or fire; and
- shortages of or delays in the receipt of necessary construction materials.

Delays in the construction and delivery of LNG tankers or other shortages in LNG tankers could result in decreases in the demand for LNG, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Technological innovation may render our anticipated competitive advantage or our processes obsolete.

Our success will depend on our ability to create and maintain a competitive position in the natural gas liquefaction industry. In particular, we are constructing our projects using technologies that we believe provide us with certain advantages (such as the mid-scale natural gas liquefaction trains to be supplied by Baker Hughes). However, we do not have any exclusive rights to any of the technologies that we will be utilizing, and our competitors may be planning to use similar or superior technologies.

In addition, the technologies that we are using or anticipate using in our projects may be rendered obsolete or uneconomical by technological advances, more efficient and cost-effective processes or entirely different approaches developed by one or more of our competitors or others. Our existing contractual arrangements with Baker Hughes would restrict our ability to utilize any such technological advances in our projects. Moreover, any changes to the design of our projects to incorporate any such technological advances could have a negative impact on the applications we have submitted to FERC with respect to those projects. As a result, we may not be able to take advantage of any such technological advances, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Risks Relating to Our Indebtedness and Financing

Our subsidiaries have incurred a significant amount of debt and issued a significant amount of preferred equity, which could adversely affect our financial condition.

As of December 31, 2024, our subsidiaries had approximately \$29.6 billion in outstanding debt, which consisted of \$11.1 billion of debt incurred or guaranteed by VGLNG and approximately \$18.5 billion in project-level debt financing. In addition, our project-level equity investment subsidiaries for the Calcasieu Project, Calcasieu Holdings and Calcasieu Funding, have issued preferred units for total gross proceeds of \$1.3 billion, with an aggregate liquidation preference of approximately \$2.2 billion outstanding as of December 31, 2024, some of which require us to make preferential cash distributions to the holders under certain circumstances.

VGLNG also issued 9.000% Series A Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock, with a \$1,000 liquidation preference per share, or the VGLNG Series A Preferred Shares, which are entitled to preferential cash distributions, with an aggregate liquidation preference of \$3.0 billion outstanding as of December 31, 2024. As of December 31, 2024, our subsidiaries had approximately \$1.2 billion of additional borrowing capacity under our existing financing agreements.

This substantial amount of indebtedness and preferred equity could have important consequences to us, including:

- making it more difficult for us to satisfy our obligations with respect to our existing debt and our subsidiaries' existing preferred equity;
- limiting our ability, or increasing the costs, to refinance our indebtedness;
- limiting our ability to borrow additional amounts for working capital, capital expenditures, debt service requirements, execution of our business strategy or other purposes;
- limiting our ability to use our cash and capital resources in other areas of our business because we must dedicate a substantial portion of these funds to service debt and preferred equity;
- increasing our vulnerability to general adverse economic and industry conditions, including increases in interest rates, particularly given our substantial indebtedness that bears interest at variable rates;
- limiting our ability to react to changing market conditions in our industry, to our customers' businesses and to economic downturns;
- limiting our ability to attract future customers for SPAs in connection with any expansion of our facilities compared with other companies that may have substantially less debt;
- limiting our flexibility in planning for, or reacting to, changes in our business and future business opportunities;
- limiting our ability to capitalize on business opportunities and to react to competitive pressures; and
- resulting in a material adverse effect on our business, operating results and financial condition if we are unable to service our indebtedness or obtain additional capital, as needed.

Under the terms of certain agreements governing our indebtedness, we are permitted to incur additional indebtedness, which could further accentuate these risks.

Servicing our indebtedness and preferred equity will require a significant amount of cash and we may not have sufficient cash, operating cash flows and capital resources to service our existing and future indebtedness and preferred equity.

We may be required to use a substantial portion of our cash and capital resources to pay interest and principal on our indebtedness, as well as cash distributions or other required payments on preferred equity of our subsidiaries. Such payments may reduce the funds available to us to construct and complete the Plaquemines Project, the CP2 Project, the CP3 Project, the Delta Project or any expansion thereof or other natural gas liquefaction and export facility we may develop, to acquire our LNG tankers, and for working capital, capital expenditures, and other corporate purposes, and limit our ability to obtain additional financing. This may in turn limit our ability to implement our business strategy, heighten our vulnerability to downturns in our business, the industry or in the general economy, and limit our flexibility in planning for, or reacting to, changes in our business and the industry.

We may not have sufficient cash, operating cash flows and capital resources to service our existing and future indebtedness and preferred equity. As of December 31, 2024, we do not have any material sales, operating cash flow or operating history, other than the short-term sales of LNG commissioning cargos from the Calcasieu Project prior to commencing commercial operations. We cannot assure you when we will begin to generate any operating cash flow from commercial operations. Our ability to service our debt and preferred equity will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, political, regulatory and other factors, some of which are beyond our control. We also cannot assure you that our business will generate sufficient cash flow from operations or that future financing will be available to us in amounts sufficient to enable us to make required and timely payments on our indebtedness or preferred equity, or to fund our operations.

If we face such liquidity problems, we could be forced to reduce or delay investments and capital expenditures or to dispose of material assets or operations, seek additional debt or equity capital or restructure or refinance our indebtedness or preferred equity. We may not be able to effect any such alternative measures, if necessary, on commercially reasonable terms or at all and, even if successful, those alternative actions may not allow us to make required payments on our indebtedness or preferred equity. In addition, certain agreements governing our existing indebtedness and preferred equity and the terms of such future agreements or preferred equity may also restrict our ability to raise debt or equity capital to be used to repay our existing indebtedness when it becomes due. We may not be able to consummate those dispositions or to obtain proceeds in an amount sufficient to make required payments on our indebtedness or preferred equity when due. If our cash, operating cash flows and capital resources are insufficient to fund those obligations, it could result in an event of default under such indebtedness, which, if not cured or waived, could result in the acceleration of all or a portion of our debt. As a result, our debtholders would be entitled to proceed to foreclose against all collateral that secures such debt, representing substantially all assets of the relevant project. In addition, if the distributions on preferred units issued by Calcasieu Funding are made in the form of an increase in the funding face value instead of in cash for six consecutive calendar quarters with the first full quarter following the commencement of commercial operations of the Calcasieu Project, certain investors may exercise step-in rights to control, directly or indirectly, certain of our subsidiaries and the Calcasieu Project.

As a holding company, the Company depends on the ability of its subsidiaries to transfer funds to it to meet its obligations.

The Company is a holding company for all of our operations and is a legal entity separate from its subsidiaries. As a result, the Company is dependent on the ability of its subsidiaries to make loans, pay dividends and make other payments to generate the funds necessary for the Company to meet its financial obligations and to pay dividends to stockholders, if any. The inability to receive dividends from its subsidiaries could have a material adverse effect on our business, financial condition, cash flows and results of operations. In particular, following COD of the Calcasieu Project, but prior to August 19, 2027, no distributions from Calcasieu Funding will be permitted to VGLNG, its indirect parent, until Calcasieu Funding has redeemed in cash any accrued distributions on its preferred units, which are owned by a third party. Furthermore on and after August 19, 2027, no distributions from Calcasieu Funding will be permitted to VGLNG, its indirect parent, until Calcasieu Funding has redeemed in cash all of such preferred units.

The subsidiaries of the Company have no obligation to pay amounts due on any liabilities of the Company or to make funds available to the Company for such payments. The ability of our subsidiaries to pay dividends or other distributions to the Company in the future will depend, among other things, on their earnings, tax considerations and covenants contained in any financing or other agreements, such as the covenants governing our subsidiaries' current indebtedness and preferred equity. In particular, our subsidiaries may incur additional indebtedness or issue additional preferred equity that may restrict or prohibit the making of distributions, the paying of dividends or the making of loans by such subsidiaries to the Company. In addition, such payments may be limited as a result of claims against the Company's subsidiaries by their creditors, including suppliers, vendors, lessors and employees.

If the ability of the Company's subsidiaries to pay dividends or make other distributions or payments to the Company is materially restricted by cash needs, bankruptcy or insolvency, or is limited due to operating results or other factors, we may be required to raise cash through the incurrence of debt, the issuance of equity or the sale of assets. However, there is no assurance that we would be able to raise sufficient cash by these means. This could have an adverse effect on the Company's ability to pay its obligations or pay dividends, if any, which could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Certain of our debt agreements impose significant operating and financial restrictions on our subsidiaries, and the preferred equity of our subsidiaries also gives the holders certain consent rights, all of which may prevent us from capitalizing on business opportunities or paying dividends to the Company.

The Calcasieu Pass Credit Facilities, the Plaquemines Credit Facilities and the indentures governing the VGCP Senior Secured Notes contain various covenants restricting the ability of certain of our subsidiaries to, among other things:

- incur or guarantee additional debt or issue disqualified stock or preferred stock;
- pay dividends (including to the Company) and make other distributions on, or redeem or repurchase, capital stock;
- make certain investments;
- incur certain liens;
- enter into transactions with affiliates;
- merge or consolidate;
- enter into agreements that restrict the ability of restricted subsidiaries to make dividends or other payments to the issuers;
- designate restricted subsidiaries as unrestricted subsidiaries; and
- transfer or sell assets.

In addition, the credit agreement governing the Calcasieu Pass Credit Facilities requires VGCP to maintain a historical debt service coverage ratio of 1.15:1 for the 12-month period ending as of the end of any fiscal quarter. Analogous requirements apply to VGPL under the Plaquemines Credit Facilities when certain milestones are met.

The holders of preferred units of Calcasieu Holdings (or Class B common units after they are converted according to their terms) have the right to select and appoint one manager to the board of managers of Calcasieu Holdings, and such manager's consent is required, among others, prior to:

- amending key project contracts;
- incurring any additional indebtedness in excess of $75.0 million, subject to certain exceptions; and
- issuing or redeeming equity under certain circumstances.

In addition, other than Calcasieu Holdings contributing capital in exchange for issuance of common units in Calcasieu Funding, Calcasieu Funding may not issue additional units without a majority approval of holders of its preferred units.

Moreover, the indentures governing the VGLNG Senior Secured Notes contain various covenants restricting the ability of certain of our subsidiaries to, among other things:

- incur or guarantee additional indebtedness or issue disqualified stock or certain preferred stock;
- pay dividends and make other distributions or repurchase stock;
- create or incur certain liens; and
- merge, consolidate or transfer or sell all or substantially all of their assets.

Our failure to comply with the restrictive covenants described above as well as other terms of our other indebtedness and/or the terms of any future indebtedness from time to time could result in an event of default, which, if not cured or waived, could result in our being required to repay these borrowings before their due date. If we are forced to refinance these borrowings on less favorable terms or are unable to refinance these borrowings, there could be a material adverse effect on our business, financial condition and results of operations.

Additionally, if VGLNG does not pay semi-annual dividends on the VGLNG Series A Preferred Shares, certain terms of the VGLNG Series A Preferred Shares restrict VGLNG's ability to pay dividends, repurchase its common stock, or issue certain types of securities. Furthermore, when any dividends on any VGLNG Series A Preferred Shares are in arrears for three or more consecutive semi-annual dividend periods, VGLNG is required to increase the number of members of its board of directors by two, until such time as all accrued dividends for all past dividend periods have been fully paid.

As a result of these restrictions, we will be limited as to how we conduct our business and we may be unable to raise additional debt or equity financing to compete effectively, distribute cash from our subsidiaries to the Company, or take advantage of new business opportunities. The terms of any future indebtedness we may incur or equity financing we may raise could include more restrictive covenants. We cannot assure you that we will be able to maintain compliance with these covenants in the future and, if we fail to do so, that we will be able to obtain waivers from the relevant lenders or holders and/or amend these covenants.

Our common equity interest in the Calcasieu Project will be diluted if we are unable to, or elect not to, pay certain distributions on the Holdings Preferred Units in cash.

As of December 31, 2024, a third-party investor currently holds 100% of the preferred units, or Holdings Preferred Units, of Calcasieu Holdings, which is an indirect parent entity of the Calcasieu Project. We have the option to pay the distributions on the Holdings Preferred Units either in kind in the form of issuing additional Holdings Preferred Units, or Holdings PIK Units, or in cash. Upon COD at the Calcasieu Project, Holdings Preferred Units, including any Holdings PIK Units outstanding, will automatically convert into Class B common units of Calcasieu Holdings, or Class B Common Units. Assuming that we service all future distributions on the Holdings Preferred Units until COD in cash, we expect the Holdings Preferred Units to automatically convert into a number of Class B Common Units, equal to approximately 23% of the total outstanding common units of Calcasieu Holdings, or Holdings Common Units, reducing our common equity interest in the Calcasieu Project to approximately 77%. However, if we are unable to, or elect not to, make payments on the Holdings Preferred Units in cash, our common equity interest in the Calcasieu Project could be further diluted. While we expect to continue making distributions on the Holdings Preferred Units in cash, this is based on certain assumptions which could be affected by a number of factors beyond our control. In addition, we may enter into similar equity financing arrangements in the future with respect to our other projects, including bolt-on expansions thereof. Greater dilution of our common equity interest in the Calcasieu Project or any other project would decrease our control over the Calcasieu Project (or such other project) and the amount of cash distributions that we receive from the Calcasieu Project (or such other project), which may have a material adverse effect on our business, financial condition, cash flows and results of operations.

Increases in interest rates would increase the cost of servicing our debt and could reduce our profitability.

The debt outstanding under the Calcasieu Pass Credit Facilities and the Plaquemines Credit Facilities bears interest at variable rates. While a substantial portion of such debt has been hedged to a fixed rate with interest rate swaps, increases in interest rates would increase the cost of servicing our subsidiaries' debt, even if the amount borrowed remains the same, and could materially reduce our consolidated profitability and cash flows. As a result of such increases in the cost of servicing our subsidiaries' debt, our subsidiaries may be unable to make distributions to us.

The U.S. Federal Reserve Board significantly increased the federal funds rate in 2022 and 2023, which led to an increase in the borrowing costs on our variable rate debt. If this rate remains high or is not decreased in the future, it may keep the cost of any new debt we incur at such increased levels. Any federal funds rate increases could in turn make our financing activities more costly and limit our ability to refinance existing debt when it matures or pay higher interest rates upon refinancing and increase interest expense on refinanced indebtedness.

Despite the current level of indebtedness and preferred equity issued by our subsidiaries, we expect to incur significant additional debt, some or all of which may be secured, and equity financing to fund the development, construction and completion of our projects. This could further exacerbate the risks to our financial condition described above.

Although we are subject to certain limitations on additional indebtedness and equity financing pursuant to the terms of agreements governing our existing indebtedness and preferred equity, these restrictions are subject to a number of qualifications and exceptions, and additional indebtedness and/or preferred equity incurred in compliance with these restrictions could be substantial. We expect to incur significant additional debt and equity financing to fund the development, construction and completion of the CP2 Project, the CP3 Project, the Delta Project, any potential bolt-on expansions and any other natural gas liquefaction and export facilities, or other projects, that we may decide to develop in the future. As of December 31, 2024, our subsidiaries had approximately $1.2 billion of additional borrowing capacity in the form of available commitments, comprised of approximately $313 million of construction term loans under the Plaquemines Credit Facilities, approximately $627 million of working capital loans under the Plaquemines Working Capital Facility (after giving effect to approximately $1.4 billion of letters of credit and $85 million of working capital loans issued under the Plaquemines Working Capital Facility), and approximately $231 million of working capital loans under the Calcasieu Pass Credit Facilities (after giving effect to approximately $324 million letters of credit issued under the Calcasieu Pass Working Capital Facility), all of which would have been secured. To the extent we or any of our subsidiaries incurs or issues additional debt and/or preferred equity, as applicable, the risks described in the preceding risk factors would increase.

Upon the occurrence of an event of default under our existing and future indebtedness, our lenders and the holders of our debt securities could elect to accelerate all or a portion of our debt. A delay in COD of the Calcasieu Project or Phase 1 or 2 of the Plaquemines Project beyond a certain deadline could also result in an event of default under the Calcasieu Pass Credit Facilities or the Plaquemines Credit Facilities, respectively, and/ or certain investors exercising step-in rights to control, directly or indirectly, certain of our subsidiaries and the Calcasieu Project.

If we are unable to fund our debt service obligations or comply with restrictive covenants under our existing or future indebtedness, it could result in an event of default under such indebtedness which, if not cured or waived, could result in the acceleration of some or all of our debt. If we are unable to repay those amounts, our lenders and the holders of our debt securities could proceed to foreclose against the collateral securing such indebtedness. Any such foreclosure could have a material adverse impact on our business, financial condition, cash flows and results of operations.

In particular, we granted certain of our lenders under the Calcasieu Pass Credit Facilities and holders of the VGCP Senior Secured Notes (i) a first-priority perfected security interest in substantially all of VGCP's and TCP's existing and after-acquired personal property, including, without limitation, proceeds, insurance policies, agreements, permits and bank accounts; (ii) a mortgage on all material leasehold and fee interests of VGCP, including, without limitation, the Calcasieu Project site; (iii) a first-priority perfected security interest in 100% of the equity interests in certain subsidiaries relating to the Calcasieu Project; and (iv) all proceeds of the foregoing as collateral. In addition, Calcasieu Pass Pledgor, LLC granted the lenders and holders of the VGCP Senior Secured Notes a first-priority perfected security interest in all of the equity interests in VGCP and TCP. We also granted certain of our lenders under the Plaquemines Credit Facilities (i) a first-priority perfected security interest in substantially all of Plaquemines' and Gator Express' existing and after-acquired personal property, including, without limitation, proceeds, insurance policies, agreements, permits and bank accounts; (ii) a mortgage on all material leasehold and fee interests of Plaquemines, including, without limitation, the Plaquemines Project site; (iii) 100% of the membership interests in Plaquemines and Gator Express; and (iv) all proceeds of the foregoing as collateral. As a result, the lenders under any such indebtedness could proceed to foreclose against such collateral securing the applicable indebtedness following an event of default, which would have a material adverse impact on our business, financial condition, cash flows and results of operations.

Furthermore, under the Calcasieu Pass Credit Facilities if the Calcasieu Project does not satisfy certain conditions, including commencing commercial operation and completing a required lenders' reliability test, by a specified date certain (currently June 1, 2025), an event of default under the Calcasieu Pass Credit Facilities will occur.

In addition, the holders of preferred units or Class B units in Calcasieu Holdings, or the Investors, will have the right to appoint a majority of the board of managers of Calcasieu Holdings, or the Step-In Right, upon the occurrence of certain trigger events. Such trigger events, include if the Calcasieu Project does not commence commercial operation by the date that is 45 days prior to the date certain under the Calcasieu Pass Credit Facilities, if an event of default occurs under the Calcasieu Pass Credit Facilities, and if certain distributions continue to accrue at Calcasieu Funding after COD. Because Calcasieu Holdings is the sole member of the entity that wholly owns the Calcasieu Project and the TransCameron Pipeline, the Step-In Right not only gives the Investors significant control over Calcasieu Holdings but also over the Calcasieu Project and the TransCameron Pipeline. The Investors' interests may differ from our interests or those of our stockholders, and therefore the Investors may not always exercise the control in a way that benefits us or our stockholders, which may have a negative impact on our business, financial conditions and results of operations.

Our use of hedging arrangements may adversely affect our future operating results or liquidity.

To help mitigate our exposure to fluctuations in the price, volume and timing risk associated with the purchase of natural gas, we may use futures, swaps and option contracts traded or cleared on the Intercontinental Exchange and the New York Mercantile Exchange, or the NYMEX, or over-the-counter options and swaps with other natural gas merchants and financial institutions. Any hedging arrangements would expose us to risk of financial loss in some circumstances, including when:

- expected supply is less than the amount hedged;
- the counterparty to the hedging contract defaults on its contractual obligations; or
- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

The use of derivatives also may require the posting of cash collateral with counterparties, which can impact working capital when commodity prices change.

The regulatory and other provisions of the Dodd-Frank Act and the rules adopted thereunder and other non-U.S. regulations, including EMIR and REMIT, could adversely affect our ability to hedge risks associated with our business and our operating results and cash flows.

The provisions of the Dodd-Frank Act and the rules adopted and to be adopted by the CFTC, the SEC and other federal regulators establishing federal regulation of the OTC derivatives market, and entities like us that participate in that market, may adversely affect our ability to manage certain of our risks on a cost effective basis. Such laws and regulations may also adversely affect our ability to execute our strategies with respect to hedging our exposure to variability in expected future cash flows attributable to the future sale of our LNG inventory and to price risk attributable to future purchases of natural gas to be utilized as fuel to operate our LNG terminals and to secure natural gas feedstock for our liquefaction facilities.

CFTC position limits rules restrict the amounts of certain speculative futures contracts, as well as economically equivalent options, futures and swaps for or linked to certain physical commodities, including Henry Hub natural gas, that market participants may hold, subject to limited exemptions for certain bona fide hedging positions and other types of transactions. The application of these requirements affect the overall derivatives market, including the costs and availability of the types of swaps we use to hedge or mitigate our commercial risks.

Under the CEA and the rules adopted thereunder, certain swaps may be required to be cleared through a DCO. While the CFTC has designated certain interest rate swaps and index credit default swaps for mandatory clearing, it has not yet adopted rules designating any physical commodity swaps, for mandatory clearing or mandatory exchange trading. Further, we qualify for and rely on the end-user exception from the mandatory clearing and trade execution requirements for any swaps entered into to hedge our commercial risks. If we fail to qualify for that exception as to any swap we enter into and have to clear that swap through a DCO, we could be required to post margin (or post higher margin than if we entered into an uncleared OTC swap) with respect to such swap, our cost of entering into and maintaining such swap could increase, and we would not enjoy the same flexibility with the terms of the cleared swaps that we enjoy with the uncleared OTC swaps we enter into. Moreover, the application of the mandatory clearing and trade execution requirements to other market participants, such as our counterparties, may change the market cost and general availability in the market of swaps of the type we enter into to hedge our commercial risks and, thus, the cost and availability of the swaps that we use for hedging.

For uncleared swaps, the CFTC and federal banking regulators have adopted rules to require certain market participants to collect and post initial and/or variation margin with respect to uncleared swaps from their counterparties that are financial end users and certain registered swap dealers and major swap participants. Although we believe we will not be required to post margin with respect to any uncleared swaps we enter into in the future, were we required to post margin as to our uncleared swaps in the future, our cost of entering into and maintaining swaps would be increased. In addition, some of our counterparties are subject to the regulations imposing capital requirements on them, which may increase the cost to us of entering into swaps with them because, although not required to collect margin from us under the margin rules, our counterparties may contractually require us to post collateral with them in connection with such swaps in order to offset their increased capital costs or to reduce their capital costs to maintain those swaps on their balance sheets.

While we are directly subject to only limited regulatory requirements for our derivatives, the application of these requirements to other market participants, including our counterparties, may affect the overall swaps market, including the costs and availability of swaps we may use to hedge or mitigate our risks. If, as a result of the swaps regulatory regime discussed above, we were to reduce our use of swaps to hedge our risks, our operating results and cash flows may become more volatile and could be otherwise adversely affected.

The Federal Reserve Board also has proposed rules that would limit certain physical commodity activities of financial holding companies. Such rules, if adopted, may adversely affect our ability to execute our strategies by restricting our available counterparties for certain types of transactions, limiting our ability to obtain certain services, and reducing liquidity in physical and financial markets. It is uncertain at this time whether, when and in what form the Federal Reserve Board's proposed rules regarding physical commodity activities of financial holding companies may become final and effective.

European and UK-specific regulations, including but not limited to EMIR, MiFID II, REMIT, MAR, FSMA and the RAO, govern our trading activities and our compliance with such laws may result in increased costs and risks to the business similar to the impacts stated above with respect to the Dodd-Frank Act. The increased costs may also have an adverse impact on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects. Further, any violation of the foregoing laws and regulations could result in investigations, and possible fines and penalties, and in some scenarios, criminal offenses.

Further, the potential for divergence between the UK and EU financial regulatory regimes following the UK's withdrawal from the EU, has created uncertainty among market participants and may result in additional regulatory risks and compliance costs. While it is expected that the UK will maintain regulatory standards similar to those in the EU, technical differences have emerged recently and it is likely that this trend will continue to increase over time.

We expect that our hedging activities will remain subject to significant and developing regulations and regulatory oversight, and the ultimate effect on our business of any future changes to this regulatory regime remains uncertain.

Risks Relating to Regulation and Litigation

We may fail to receive the required approvals and permits from governmental and regulatory agencies for our projects.

The design, construction and operation of the facilities constituting our projects, as well as the export of LNG and the transportation of natural gas, are highly regulated activities. Certain of our development projects remain subject to the application for and/or receipt of several material federal, state and local governmental and regulatory approvals and permits, as described further under Item 1.—*Business*—*Governmental Regulation* of this Form 10-K. Approvals of FERC and DOE under Sections 3 and 7 of the Natural Gas Act, or the NGA, as well as several other material governmental and regulatory approvals and permits, including under the Clean Air Act, or the CAA, and the Clean Water Act, or the CWA, are required in order to construct and operate an LNG facility and a natural gas pipeline, and to export the LNG produced at our projects. See also Item 1.—*Business*—*Environmental Regulation* of this Form 10-K. Our projects that have obtained needed approvals and permits remain subject to extensive regulation.

The authorizations obtained from FERC, DOE and other federal and state regulatory agencies also contain ongoing conditions, and such agencies may impose additional approval and permit requirements. DOE has stated that it has authority to amend, modify, or revoke existing LNG export authorizations issued pursuant to Section 3 of the NGA if necessary or appropriate to protect the public interest. In addition, the DOE may suspend or revoke our export authorizations if we, our customers, and/or their downstream customers, do not comply with the terms and conditions of the authorizations or if the DOE later determines that LNG exports are contrary to the public interest.

While we have received the applicable approvals from the Office of Fossil Energy and Carbon Management of the DOE authorizing the export of domestically produced LNG for the nameplate capacity as well as excess capacity up to the current permitted liquefaction capacity for the Calcasieu Project and the Plaquemines Project, our requests to increase the authorized export volumes from both projects to reflect an increased peak output have been granted only with respect to exports to FTA Nations while the requests with respect to Non-FTA Nations remain pending. Similarly, DOE has authorized LNG exports from the CP2 Project only to FTA Nations while our non-FTA application for that project remains pending. We have not yet made filings to the DOE regarding the export of any natural gas from the CP3 Project or the Delta Project. Moreover, we have not made any filings with DOE with respect to any of the potential bolt-on expansion opportunities at any of our projects.

In January 2024, the Biden administration announced a temporary pause on new authorizations of natural gas exports to Non-FTA Nations while the DOE conducts studies to update its analyses regarding whether the exports are "not inconsistent with the public interest" to consider the latest available information regarding macro-economic impacts, domestic energy prices, potential GHG, climate or other environmental effects, and national security implications.

On December 17, 2024, DOE publicly released a multi-volume study of its views of the potential effects of U.S. LNG exports on the domestic economy; U.S. households and consumers; communities that live near locations where natural gas is produced or exported; domestic and international energy security, including effects of U.S. trading partners; and the environment and climate. DOE stated that it intends to use this study to inform its public interest review of and future decisions regarding exports to Non-FTA Nations. The study was initially subject to a public comment period scheduled to expire on February 18, 2025. On January 20, 2025, President Trump issued an Executive Order entitled "Unleashing American Energy," that, among other provisions, directed DOE to restart reviews of applications for approvals of LNG exports and directed the consideration of the economic and employment impacts to the U.S. and the impact to the security of allies and partners that would result from granting the application. Other parts of the wide-ranging Executive Order require expedited permitting and elimination of delays and revoke prior executive orders related to the CEQ and GHG emissions. A second Executive Order issued that same day declared a "National Energy Emergency" and, among other things, recognized the benefits of selling LNG to international allies and partners. On January 21, 2025, DOE directed to the Office of Fossil Energy and Carbon Management to resume consideration of pending applications for LNG exports in accordance with the Natural Gas Act and extended the comment period on the DOE study to March 20, 2025 "to ensure such public interest determinations receive appropriate stakeholder input." On February 14, 2025, DOE Secretary Wright announced the issuance of a conditional authorization to export LNG to Non-FTA Nations to Commonwealth LNG. Nevertheless, there can be no assurance as to DOE's further implementation of the Executive Orders, the new Administration's views of the recently released DOE study or its future policies, or the impact of those policies on our existing and future projects, including our related contracts.

While FERC has authorized the siting, construction and operation of the Calcasieu Project and the Plaquemines Project, as well as of the related pipelines under Sections 3 and 7 of the NGA, additional authorizations from the Commission and/or staff of FERC, as applicable, to proceed with the construction of facilities for the Plaquemines Project and to complete commissioning and place facilities into commercial service, are required as part of FERC's ongoing regulation of our projects. We may face additional regulatory risks from time to time as they are based on various factors outside of our control. There can be no assurance that we will not face additional regulatory risks from FERC.

The FERC issued its order authorizing the CP2 Project in June 2024. In July 2024, a group of opponents composed mostly of environmental groups filed a request for rehearing of the FERC authorization, raising a number of challenges to the FERC authorization. In a notice issued on August 29, 2024, FERC denied rehearing by operation of law. Project opponents consisting of numerous environmentalist organizations and certain individuals filed petitions for review of FERC's authorization order with the US Court of Appeals for the D.C. Circuit on September 4, 2024. FERC denied a motion for stay of its authorization order on October 1, 2024. The D.C. Circuit denied a similar request for stay filed by project opponents on November 8, 2024, and established a schedule providing for briefing through April 2025.

On November 27, 2024, FERC issued an order on rehearing that generally rejected the arguments opposing the CP2 Project and noted that it remains confident in the authorization order, but decided to partially "set aside" its prior analysis of the cumulative air impacts of emissions of nitrogen dioxide (NO_2) and particulate matter less than 2.5 micrometers ($PM_{2.5}$) and to prepare a supplemental Environmental Impact Statement concerning that topic and to address it along with certain other air quality issues in a future order. FERC also announced that, due to its initiation of supplemental environmental review, it will not issue authorizations to proceed with construction until FERC issues a further merits order. In response to FERC's order on rehearing, the D.C. Circuit on December 13, 2024, granted an unopposed motion by FERC to hold the appeal in abeyance, which will delay briefing of the D.C. Circuit appeal. On February 7, 2025, FERC issued a draft supplemental Environmental Impact Statement, concluding that the project will have no significant cumulative air quality impacts and that all its previous environmental conclusions remain unchanged. Public comments on the draft Environmental Impact Statement are due by March 31, 2025, and FERC's schedule provides for the Final Environmental Impact Statement to be issued by May 9, 2025. We may face additional regulatory risks from time to time as they are based on various factors outside of our control. There can be no assurance that we will not face additional regulatory risks from FERC, including as a result of additional supplemental environmental impact reviews in the future.

In addition to the appeal, construction of the CP2 Project will be subject to ongoing oversight and needed additional authorizations by FERC in accordance with the terms and conditions of the CP2 Project FERC order.

While we have already begun to submit implementation plans for that purpose, FERC has not yet authorized any on-site construction as of the date of this Form 10-K. There can be no assurance as to the timing of FERC's further merits order or authorizations from FERC for any on-site construction, and as a result there can be no assurance as to when we will be able to commence on-site construction for the CP2 Project.

We cannot predict whether our applications, approvals or permits will attract significant opposition or whether the permitting process will be lengthened due to complexities and appeals, including uncertainty and delays in the timetable on which the DOE will issue the non-FTA export authorization for the CP2 Project and for increases in the peak output for the Calcasieu and Plaquemines Projects, as well as for the FERC and DOE to act on future applications for the CP3 Project, the Delta Project or any potential bolt-on expansion opportunities in our projects in the future, litigation by environmental groups and other advocates concerned about the impact of our projects on climate change and pollution as well as resistance by local communities due to environmental, health and safety concerns. A number of environmental groups have opposed the regulatory approvals necessary for the CP2 Project, as well as the increase in the permitted capacity for the Plaquemines Project.

Opposition to our projects from environmental groups and other advocates may increase and strengthen over time. As noted above, opponents of the CP2 Project have both sought rehearing of and appealed the FERC authorization of the project. Those entities likely will continue to oppose the CP2 Project and its regulatory authorizations, including its export authorization for Non-FTA Nations. Any appeal of or litigation relating to our permits or approvals may delay the development of our natural gas liquefaction and export facilities. There can be no assurance that any opposition, appeals or other litigation, which may be entered after the granting of authorization by FERC (as in the existing appeal) or DOE (once it issues the non-FTA authorization), will not be successful or not delay our ability to develop the CP2 Project, the CP3 Project or the Delta Project, any bolt-on expansion to any of our projects we pursue in the future, or any other project we may seek to develop.

We do not know whether or when any of the approvals or permits we require can be obtained, whether any existing or potential future interventions or other actions by third parties will interfere with our ability to obtain and maintain such approvals or permits, whether any such approvals and permits may be revoked or altered in the future, or whether we will be able to comply with the conditions or requirements that such approvals or permits might impose. In addition, requests by regulators for additional information or additional regulatory submissions may delay the regulatory approval process and may also lead to changes in our project design. There is no assurance that we will obtain and maintain these governmental approvals and permits, or that we will be able to obtain them on a timely basis.

The denial of an application, approval or permit essential to a project or bolt-on expansion opportunity or the imposition of impractical conditions would impair our ability to develop a project or bolt-on expansion opportunity. Similarly, a delay in the review and permitting process for our projects or bolt-on expansion opportunities could impair or delay our ability to develop the relevant project or bolt-on expansion opportunity or increase the cost so substantially that the relevant project or bolt-on expansion opportunity is no longer financially attractive to us. In particular, certain of the foregoing approvals and permits must be obtained before construction of the CP2 Project, the CP3 Project and the Delta Project can begin, before the Plaquemines Project is completed, before commercial operations of the Calcasieu Project can commence, and before we can pursue any potential bolt-on expansion opportunities at our projects. If we are unable to obtain and maintain the necessary approvals and permits or satisfy additional permit requirements imposed on us, we may not be able to complete our projects on schedule or operate them and provide services to our customers under the SPAs and, consequently, a failure to obtain and maintain any of these permits, approvals or authorizations could have a material adverse effect on our business, financial condition, operating results, liquidity and prospects.

In the future, additional regulatory approvals may be required or significant costs may be incurred due to delays caused by the opposition, changes in laws and regulations or for other reasons. In addition, zoning, environmental, health and safety laws and regulations are subject to periodic amendment or promulgation and may become more stringent over time. Accordingly, we cannot assure that such laws or regulations will not be changed or reinterpreted or that new laws or regulations will not be adopted. The costs of complying with future laws and regulations may require us to incur materially higher costs.

There can be no assurance that our existing or future regulatory approvals will not be subject to other legal challenges, or that such approvals will not be re-examined vacated, withdrawn, overturned, altered or otherwise modified in a manner adverse to the development, construction or operation of one or more of our projects or to our business more generally. If we are required to modify our activities as a result of any changes to our existing regulatory approvals, the impact could increase our project costs, delay our project timelines, affect our ability to complete our planned projects, or result in claims from third parties if we are unable to meet our commitments under our pre-existing commercial agreements, all of which could have a material adverse effect on our business. As of the date of this Form 10-K, we have not yet submitted a formal FERC application for the CP3 Project or the Delta Project, but we have requested initiation of the pre-filing process with FERC with respect to an additional 18.6 mtpa of bolt-on expansion peak production capacity at the Plaquemines Project.

Our interstate natural gas pipelines and their FERC gas tariffs are subject to FERC regulation.

Our natural gas pipelines providing interstate transportation are subject to regulation by FERC under the NGA and under the Natural Gas Policy Act of 1978, or the NGPA. FERC regulates the transportation of natural gas in interstate commerce, including the construction and operation of pipelines, the rates, terms and conditions of service and abandonment of facilities. Under the NGA, the rates charged by interstate natural gas pipelines must be just and reasonable, and we are prohibited from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service. If our interstate natural gas pipelines fail to comply with all applicable statutes, rules, regulations and orders, they could be subject to substantial penalties and fines.

As our interstate natural gas pipelines are subject to FERC regulations, we must file FERC gas tariffs, as well as any subsequent changes to the filed FERC gas tariffs or agreements related to the pipelines from time to time, with FERC for approval for each of our pipelines. The construction and operation of any new, modified, or expanded facilities on our pipelines may also require FERC authorization. There can be no assurance that FERC will accept such filings on anticipated terms and timelines, or at all.

Should we, or any of our applicable subsidiaries that own a FERC-jurisdictional pipeline fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we or such subsidiary could be subject to substantial penalties and fines. Under the Energy Policy Act of 2005, or EPAct, FERC has civil penalty authority under the NGA and the NGPA to impose penalties for violations of currently up to approximately $1.58 million (with future changes indexed to inflation) per day for each violation.

Pipeline safety integrity programs and repairs may impose significant costs and liabilities on us.

The Pipeline and Hazardous Materials Safety Administration, or PHMSA, has exclusive authority to establish and enforce safety regulations for onshore LNG facilities and pipelines transporting hazardous materials such as natural gas. PHMSA periodically inspects LNG facilities and operators to enforce compliance with the applicable safety regulations. During the inspections, PHMSA reviews operator records to determine if facility equipment has been properly maintained and if the operator has developed and follows operation, maintenance, security, and emergency procedures that ensure the continued safe operation of the facility. Compliance with PHMSA requirements, which may change over time, can impose additional costs or liabilities on us or adversely affect our operations. PHMSA enforces violations it finds, which can include civil penalties or orders directing action. In addition, if PHMSA finds conditions that are hazardous, it can require the shut-down of the relevant facilities and expeditious corrections of the conditions through corrective action orders.

PHMSA also requires pipeline operators to develop integrity management programs to comprehensively evaluate certain areas along their pipelines and to take additional measures to protect pipeline segments located in "high consequence areas" where a leak or rupture could potentially do the most harm. As an operator, we are required to:

- perform ongoing assessments of pipeline integrity;

- identify and characterize applicable threats to pipeline segments that could impact a "high consequence area";
- improve data collection, integrate and analyze pipeline data;
- repair and remediate the pipeline as necessary; and
- implement preventative and mitigating actions.

We are required to maintain pipeline integrity testing programs that are intended to assess pipeline integrity. The costs of compliance with integrity management programs and other PHMSA requirements may be difficult to predict. Furthermore, these standards are subject to regular statutory and regulatory revision and generally have become more stringent over time, as PHMSA promulgates new or revised regulations and as Congress amends existing pipeline safety laws. If these standards become more stringent in the future, it could cause us, like other similarly situated pipeline operators, to incur increased costs for operating our pipelines, to incur increased costs for developing future projects or bolt-on expansion opportunities, or to suffer potential adverse impacts to our operations. For instance, on May 4, 2023, PHMSA issued a proposed rulemaking implementing a mandate under the Protecting Our Infrastructure and Enhancing Safety Act of 2020, or the PIPES Act, to reduce methane emissions from new and existing natural gas transmission, regulated gathering and distribution pipelines, natural gas storage, and LNG facilities. The proposed rule imposes enhanced leak survey and patrolling requirements, standards for leak detection programs, leak grading and repair criteria, repair timelines, requirements for mitigation of emissions from blowdowns, requirements for investigating failures, and criteria for the design, configuration and maintenance of pressure relief devices. Although PHMSA issued a final version of this rule on January 17, 2025, the rule was never published in the Federal Register prior to a regulatory freeze issued by the Trump administration on January 20, 2025. Although we do not expect this version to be issued in its current form, any future rule implementing these mandates under PIPES Act may require operators of pipelines and facilities to make operational changes or modifications at their facilities to meet standards beyond current requirements, which changes or modifications may result in additional capital costs, possible operational delays and increased costs of operation that, in some instances, may be significant.

Any repair, remediation or delayed remediation, preventative or mitigating actions may require significant capital and operating expenditures and may subject us to significant reputational or financial risk. Should we fail to comply with applicable statutes and the PHMSA rules and related regulations and orders, we could be subject to significant penalties and fines, which would have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Existing and future environmental and similar laws and governmental regulations could result in increased compliance costs or additional operating and/or construction costs and restrictions.

Our business is and will be subject to extensive federal, state and local laws and regulations that regulate and restrict, among other things, discharges to air, land and water, with particular respect to the protection of the environment and natural resources; the handling, storage and disposal of hazardous materials, hazardous waste, and petroleum products; and investigation and remediation associated with the release of hazardous substances. Many of these laws and regulations, such as the CAA, Oil Pollution Act, or OPA, CWA, Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, and Resource Conservation and Recovery Act, or RCRA, and analogous state laws and regulations, restrict or prohibit the types, quantities and concentration of substances that can be released into the environment in connection with the construction and operation of our projects and any other natural gas liquefaction and export facility we may decide to develop in the future, and require us to maintain permits and provide governmental authorities with access to our facilities for inspection and to provide reports related to our compliance. In addition, certain laws and regulations authorize regulators having jurisdiction over the construction and operation of our projects and related pipelines, including FERC, PHMSA, EPA and the United States Coast Guard, to issue regulatory enforcement actions, which may restrict or limit operations or increase compliance or operating costs. Violation of these laws and regulations could lead to substantial liabilities, compliance orders, fines and penalties, operational or construction restrictions, difficulty obtaining and maintaining permits from regulatory agencies or capital expenditures and operational costs related to pollution control equipment that could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Federal and state laws impose liability, without regard to fault or the lawfulness of the original conduct, for the release of certain types or quantities of hazardous substances into the environment. As the owner and operator of the proposed liquefaction facilities, we could be liable for the costs of investigating and cleaning up hazardous substances released into the environment at or from our facilities and for resulting damage to natural resources, including as they relate to releases of hazardous substances that pre-date our possession and operation.

We have conducted Phase I environmental studies on all of our project sites, and from time to time we have encountered environmental conditions on certain sites that we may be required to monitor or address prior to making use of the relevant project site. In addition, future studies and analyses may reveal adverse environmental conditions on them of which we are not currently aware, and we may be required to investigate and remediate such conditions or make other changes to those sites. Any discovery of preexisting, or occurrence of new, environmental conditions that require remediation or other alterations to our current plans for our projects could delay or prevent the construction of that project, or require us to pay penalties or fines or otherwise incur significant losses and liabilities, any of which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

On December 15, 2009, the Environmental Protection Agency, or the EPA, published its findings that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to human health and the environment because emissions of such gases are, according to EPA, contributing to the warming of the Earth's atmosphere and other climatic changes. Federal and state regulatory authorities have been pursuing a number of regulatory and policy initiatives to reduce GHG emissions in the United States from a variety of sources, but such initiatives can be controversial and subject to change depending on legal and political developments. For example, on May 9, 2024, the EPA finalized a new rule regulating GHG emissions from the power sector that would phase in requirements for certain fossil fuel-fired power plants to implement GHG reduction methods, including, among other things, the installation of systems to capture and sequester their carbon emissions. This rule is the subject of legal challenges pending before the Court of Appeals for the District of Columbia.

On December 2, 2023, EPA issued a final rule updating and broadening requirements for new, modified, and reconstructed oil and gas sources, including oil and gas wells, controllers, pumps, storage vessels, and compressor stations aimed at reducing methane and volatile organic compound emissions and directing states to develop plans largely paralleling these requirements for hundreds of thousands of existing oil and gas sources. The rule also includes a Super-Emitter Response Program, whereby qualified third parties may document super-emitter events and notify owners or operators of affected sites, requiring them to investigate and take measures to mitigate methane emissions. This rule is subject to pending legal challenges in the Court of Appeals for the District of Columbia as well. On January 20, 2025, President Trump signed an Executive Order to once again withdraw the U.S. from the Paris Agreement as well as a wide-ranging Executive Order entitled "Unleashing American Energy," that, among other provisions, directed all agencies to adhere to only relevant legislated requirements for environmental considerations and to prioritize energy production, and directed EPA to consider eliminating the social cost of carbon from permitting or regulatory decisions and reconsider its 2009 finding that GHG emissions endanger human health and the environment, which provides legal support for EPA GHG emissions regulations. The future impact of these actions, and the new administration generally, on existing climate-related regulations cannot be predicted at this time.

Section 60113 of the Inflation Reduction Act, which was signed into law on August 16, 2022, establishes a charge on excess methane emissions from various facilities operating in the oil and gas sector, including liquefied natural gas storage and liquefied natural gas import and export equipment, that report more than 25,000 metric tons of carbon dioxide equivalent emissions per year. For liquefied natural gas facilities, the excess emissions charge ($900 per ton for emissions reported in calendar year 2024, rising to $1,500 per ton for such emission beginning with calendar year 2026) is based on the reported tons of methane emissions that exceed 0.05 percent of the natural gas sent to sale from or through such facilities. We anticipate that our facilities would be subject to such excess emissions charge. In February 2025, Congress approved a measure to repeal the EPA rule implementing the emissions charge, and this measure currently awaits President Trump's signature. The future prospects of the emissions charge are uncertain.

The United States Congress has also considered other legislation to restrict or regulate emissions of GHGs. While it remains unclear whether Congress will be able to agree on comprehensive climate legislation in the near future, energy legislation and other initiatives may seek to address GHG emissions issues or restrict oil and gas operations. In addition to the uncertainties in federal climate policy, we could still be subject to or impacted by international initiatives, state initiatives or by future federal regulatory initiatives, which could include direct GHG emissions regulations, a carbon emissions tax, or cap-and-trade programs. Such initiatives could affect the demand for or cost of natural gas, which we consume at our terminals, or could increase compliance costs for our operations.

Other federal and state initiatives, as well as initiatives in foreign jurisdictions where we intend to market our products, have been implemented, are being considered or may be considered in the future to address GHG emissions and other climate and environmental concerns. These may include, but are not limited to, treaty commitments, direct regulation, carbon emissions taxes, cap and trade programs or mandates to the power sector to incorporate certain percentages of renewable energy into their portfolio. For example, the EU has adopted a legally binding target of net zero GHG emissions by 2050. Additionally, in August 2024, an EU regulation went into effect that is aimed at reducing methane emissions associated with natural gas, oil and coal imports and imposes monitoring, reporting and verification standards on importers of fossil fuels into the EU with respect to the "life cycle" methane emissions associated with the products.

In addition, from time to time, proposals have been made to change the way FERC considers GHG emissions in reviewing applications under the National Environmental Policy Act, or NEPA, and the NGA. For example, in February 2022, FERC released an interim policy statement for consideration of GHG emissions in natural gas infrastructure reviews, though it later converted it to a draft statement subject to further comment. On January 24, 2025, FERC withdrew this policy and stated that impacts associated with GHG emissions would be considered on a case-by-case basis. In May 2024, the CEQ published its final "Phase 2" NEPA regulations which include specific direction to account for both climate change and environmental justice effects in NEPA reviews. Such initiatives could affect the demand for, or the availability or cost of, natural gas, which we consume at our terminals, or could increase compliance costs for our operations. The impact on these initiatives of the new Trump administration with respect to energy policy and climate change, including CEQ's publication in the Federal Register on February 25, 2025 of an interim final rule which will rescind its NEPA regulations in their entirety effective April 11, 2025 (subject to CEQ's consideration of public comments submitted by the effective date), and President Trump's executive orders directing CEQ to issue guidance and coordinate agency level regulations that expedite permitting and prioritizes energy production, cannot be fully predicted at this time.

GHG emissions (such as carbon dioxide and methane) that could be regulated include, among others, those associated with our power generation, liquefaction and transportation of natural gas, and consumers' or customers' use of our products. Many of these activities, such as consumers' and customers' use of our products, as well as actions taken by our competitors in response to such laws and regulations, are beyond our control. Attention to climate change risks has also resulted and may continue to result in private initiatives by certain members of the investment community as well as public interest groups aimed at discouraging the production, development and consumption of fossil fuels.

GHG emissions-related laws and related regulations, consumer and investor preferences with respect to fossil fuels and the effects of operating in a potentially carbon-constrained environment may result in substantially increased capital, compliance, operating and maintenance costs and could, among other things, reduce demand for LNG, make our products more expensive and adversely affect our sales volumes, revenues and margins.

The ultimate effect of international agreements and national, regional and state legislation and regulatory measures to limit GHG emissions on our financial performance, and the timing of these effects, will depend on numerous factors. Such factors include, among others, the sectors covered, the GHG emissions reductions required and the extent to which we are able to recover the costs incurred through the pricing of our products in the competitive marketplace. Further, the ultimate impact of GHG emissions-related agreements, legislation, regulations, or private initiatives on our financial performance is highly uncertain because the company is unable to predict with certainty, for a multitude of individual jurisdictions, the outcome of political decision-making processes and the variables and tradeoffs that inevitably occur in connection with such processes and the timing thereof.

Other future legislation and regulations, such as those relating to the transportation and security of LNG exported from our projects, could cause additional expenditures, restrictions and delays in our business and to our proposed construction, the extent of which cannot be predicted and which may require us to limit substantially, delay or cease operations in some circumstances. Revised, reinterpreted or additional laws and regulations that result in increased compliance costs or additional operating or construction costs and restrictions could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

We are involved and may in the future become involved in disputes and legal proceedings.

We are involved in or may in the future become involved in disputes as well as legal proceedings with public authorities, shareholders, suppliers, contractors, customers and others. Given the nature of our business, such disputes and legal proceedings often involve highly complex legal and factual questions and determinations and, in some cases, introduce significant levels of exposure.

For example, the Calcasieu Project is currently involved in arbitration proceedings with certain of its customers under post-COD SPAs related to the Calcasieu Project. See *—If we are unsuccessful in any current or potential future arbitration proceedings with customers, the amounts that we are required to pay may be substantial or certain of our post-COD SPAs may be terminated, which may lead to an acceleration of all our debt for the relevant project.*

In addition, in 2024 certain of our former employees filed proceedings, including in Virginia federal court, seeking aggregate damages of approximately $214 million with respect to alleged breaches of certain stock option grant agreements and related matters. We disagree with the assertions in each of these proceedings and are defending ourselves and asserting counterclaims, where applicable. However, there can be no assurance that we will be successful in defending such claims.

Further, a putative securities class action complaint naming Venture Global, our directors and certain of our officers was filed in the U.S. District Court for the Southern District of New York on February 17, 2025. The complaint asserts claims under Sections 11 and 15 of the Securities Act on behalf of a putative class of all persons and entities who purchased or otherwise acquired our Class A common stock pursuant and/or traceable to the registration statement for the IPO. It contends that certain statements made by the Company and certain of its officers and directors in the registration statement and prospectus for the IPO were allegedly false or misleading and seeks unspecified damages on behalf of the putative class. The Company believes these claims, along with the third party statements on which they are based, are without merit and intends to defend itself vigorously. However, there can be no assurance that we will be successful in defending such claims.

Further, from time to time, we may be a party to various administrative, regulatory or other legal proceedings, and others may allege that we are in violation or in default under orders, statutes, rules or regulations relating to the environment, compliance plans imposed or agreed to by us, or permits issued by various local, state or federal agencies for the construction or operation of our natural gas liquefaction facilities. For instance, BP Gas Marketing Limited filed a complaint with FERC in December 2023, which was subsequently withdrawn in July 2024, alleging that the Calcasieu Project had actually met the requirements for FERC to put it in-service since 2022 and is operating commercially and sought to consolidate this proceeding with the ongoing FERC proceeding for the construction and commissioning of the Calcasieu Project. In addition, when the Calcasieu Project filed with FERC in February 2024 for an extension of time, if deemed necessary, of the condition in our February 2019 FERC authorization order requiring the Calcasieu Project's "proposed liquefaction facilities" be placed in-service within five years of the order, the Calcasieu Project's long-term customers filed numerous responsive pleadings, predominantly seeking access to information filed with FERC on a confidential basis and to intervene in the ongoing commissioning process. The Calcasieu Project has responded to customer filings in the extension of time filing proceeding, which remains pending before FERC.

Assessment of potential outcomes and the potential damages and other losses we may incur arising out of any current or future disputes or legal proceedings is inherently difficult given, *among other things*, the complex nature of the facts and law involved. Although we may disagree with any assertions and claims made against us in any such disputes or legal proceedings, we may not be successful in defending against such claims. If legal proceedings are resolved against us or if we make out-of-court settlements, we may be obliged to make substantial payments to other parties. Even if we are ultimately successful in the legal proceedings, such proceedings may distract our management team and we may also face harm to our reputation from case-related publicity. Further, any such disputes or legal proceedings could result in substantial costs to us associated with defending such claims and distract management, could have a material adverse effect on our reputation, and could also impact our ability to complete our projects and any natural gas liquefaction and export facility we may decide to develop in the future on their respective anticipated timelines and at their respective anticipated costs.

If we are unsuccessful in any current or potential future arbitration proceedings with customers, the amounts that we are required to pay may be substantial or certain of our post-COD SPAs may be terminated, which may lead to an acceleration of all our debt for the relevant project.

We are involved and may in the future become involved in disputes and arbitration proceedings with the customers under our SPAs. For example, in December 2022, a long-term customer of the Calcasieu Project submitted a request for arbitration to the International Chamber of Commerce, International Court of Arbitration, in accordance with the dispute resolution procedures of the post-COD SPA between us and that customer, asserting that the Calcasieu Project had failed to provide sufficient information or access regarding the Calcasieu Project and that it was delayed in achieving COD under the post-COD SPA. The remedies sought by the long-term customer are damages of approximately $1 billion (which is potentially subject to increase with the passage of time until COD occurs), rather than the termination of the post-COD SPA. The liability portion of the merits hearing for this arbitration proceeding occurred in September 2024.

In May 2023, two additional long-term customers of the Calcasieu Project submitted separate requests for arbitration to the London Court of International Arbitration and the International Chamber of Commerce, International Court of Arbitration, respectively, in accordance with the dispute resolution procedures of the relevant post-COD SPAs with such customers, asserting, among other claims, that the Calcasieu Project is delayed in achieving COD under the post-COD SPA. The remedies sought by each such long-term customer are (a) orders requiring the Calcasieu Project to immediately notify the relevant long-term customer of the occurrence of COD of the Calcasieu Project or otherwise deliver LNG cargos to the relevant long-term customer at the contract price set forth in the applicable post-COD SPA; and (b) damages of approximately $1.5 billion and $1.7 billion (each of which is potentially subject to increase with the passage of time until COD occurs), respectively, rather than the termination of the relevant post-COD SPAs. The hearings for such two arbitration proceedings occurred in October 2024 and November 2024, respectively.

In August 2023, two additional long-term customers of the Calcasieu Project submitted separate requests for arbitration to the International Chamber of Commerce, International Court of Arbitration in accordance with the dispute resolution procedures of the relevant post-COD SPAs with such customers, asserting, among other claims, that the Calcasieu Project is delayed in achieving COD under the relevant post-COD SPA. The hearings for such two arbitration proceedings have been scheduled for June 2025 and July 2025, respectively. In December 2023, one additional long-term customer of the Calcasieu Project submitted a request for arbitration to the International Chamber of Commerce, International Court of Arbitration in accordance with the dispute resolution procedures of the post-COD SPA between us and that customer, asserting among other claims that the Calcasieu Project is delayed in achieving COD under the relevant post-COD SPA. The remedies sought by each of the second group of three long-term customers are (a) orders requiring the Calcasieu Project to immediately notify the relevant long-term customer of the occurrence of COD of the Calcasieu Project or otherwise deliver LNG cargos to the relevant long-term customer at the contract price set forth in the applicable post-COD SPA; and (b) damages in an amount to be determined in excess of $2.0 billion (in the case of one such customer, pursuant to a further filing submitted in

February 2025) or of approximately $400 million (in the case of two such customers), rather than the termination of the relevant post-COD SPAs.

Further, in March 2024, a mid-term customer of the Calcasieu Project submitted a request for arbitration to the International Chamber of Commerce, International Court of Arbitration in accordance with the dispute resolution procedures of the post-COD SPA between us and that customer. Such customer has raised substantially the same assertions as the arbitration proceedings described above and is seeking damages of approximately $200 million (which is potentially subject to increase with the passage of time until COD occurs), as well as an additional claim relating to an undelivered commissioning cargo. Additionally, all such customers who have asserted that we are delayed in achieving COD have also disputed that the delay to COD constitutes a *force majeure* event in the context of their arbitration proceedings. We disagree with the assertions and legal claims in each of these requests for arbitration, and the Calcasieu Project is defending the arbitration proceedings in accordance with each underlying post-COD SPA. We further believe that any damage award would be subject to the relevant seller aggregate liability cap under the relevant post-COD SPA. However, there can be no assurance that the Calcasieu Project will be successful in defending such claims or establishing that any such claim is subject to the liability cap under the relevant post-COD SPA.

In addition, although none of the post-COD SPA customers who have commenced the arbitration proceedings described above has sought termination of the underlying post-COD SPA as a remedy in the relevant arbitration, two of those long-term post-COD SPA customers have notified the collateral agent for the Calcasieu Project's project financing that a potential termination event under their long-term post-COD SPA has occurred or may occur, and that remedies could include termination of, or suspension under, the relevant long-term post-COD SPA.

If the Calcasieu Project is unsuccessful in defending against any of the claims mentioned above, the amounts it could be required to pay could be substantial, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects. Further, a termination of, or suspension under, any of the relevant long-term post-COD SPAs that are subject to these claims could, subject to our ability to replace such long-term post-COD SPAs during the applicable grace period, lead to an acceleration of our outstanding debt under the Calcasieu Project and foreclosure against all collateral that secures such debt, representing substantially all assets of the Calcasieu Project, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

The Calcasieu Project has also notified all of its customers under the Calcasieu Foundation SPAs of a *force majeure* event in connection with the Calcasieu Project's HRSG units. As a result of such designation, the deadline for COD in such post-COD SPAs would be extended and such customers will not be entitled to terminate their respective post-COD SPAs as a result of failure to designate COD until June 2025. All of such customers have questioned (including, as applicable, in the post-COD SPA arbitration proceedings described above) whether the delay constitutes a *force majeure* event. These customers could assert that, notwithstanding the Calcasieu Project's declaration of *force majeure*, they are entitled to terminate their post-COD SPAs. Discussions with such customers with respect to this *force majeure* event remain ongoing. Such customers may also seek damages, and several such customers have already sought damages in connection with the alleged delay in achieving COD for the Calcasieu Project as described above. Any such damages claims could be substantial, and there can be no assurance that the Calcasieu Project will be successful in defending any such claims.

If certain customers were to successfully terminate their post-COD SPAs for the Calcasieu Project, we would need to replace those customers and/or amend the Calcasieu Project's existing post-COD SPAs over a certain period of time that may extend up to 180 days, which could take time and there can be no assurance we would be able to enter into new post-COD SPAs on a timely basis and on comparable or better terms. See *—Risks Relating to Our Business—Our customers or we may terminate our SPAs if certain conditions are not met or for other reasons.* See also *—Risks Relating to Our Indebtedness and Financing—Upon the occurrence of an event of default under our existing and future indebtedness, our lenders and the holders of our debt securities could elect to accelerate all or a portion of our debt. A delay in COD of the Calcasieu Project or Phase 1 or 2 of the Plaquemines Project beyond a certain deadline could also result in an event of default under the Calcasieu Pass Credit Facilities or the*

Plaquemines Credit Facilities, respectively, and/or certain investors exercising step-in rights to control, directly or indirectly, certain of our subsidiaries and the Calcasieu Project.

Risks Relating to Intellectual Property, Data Privacy and Cybersecurity

Hostile cyber intrusions, or other issues with our information technology, could severely impair our operations, lead to the disclosure of confidential information, damage our reputation and otherwise have a material adverse effect on our business.

Our projects and any other natural gas liquefaction and export facilities (including any expansion of existing facilities) we may decide to develop in the future include assets deemed by FERC to constitute critical energy infrastructure, the operation of which is dependent on our information technology, or IT, systems. The IT systems that run our natural gas liquefaction and export facilities are not completely isolated from external networks. A successful cyber-attack on the systems that will control our assets could severely disrupt business operations, preventing us from serving customers or collecting revenues, as well as expose us to other risks. Additionally, a successful cyber-attack against a pipeline which supplies our LNG facilities could affect our ability to obtain physical delivery of sufficient natural gas to operate at full capacity, or at all.

Other exposure to various types of cyber-attacks, such as malware, ransomware, viruses, denial of service attacks, social engineering, password spraying, credential stuffing, phishing or other malicious or fraudulent acts, as well as human error or malfeasance, could also potentially disrupt our operations. Such security threats are increasing in frequency and sophistication and pose a risk to the security of our IT systems and the confidentiality, availability and integrity of the information we process and maintain. We also may be vulnerable to interruption and breakdown by fire, natural disaster, power loss, telecommunication failures, internet failures and other catastrophic events. We may experience occasional system interruptions and delays that make our IT systems unavailable or slow to respond, including the interaction of our IT systems with those of third parties.

Cybersecurity threats are persistent and evolve quickly, and we may in the future experience such threats. Such threats have increased in frequency, scope and potential impact in recent years because of the proliferation of new technologies, including artificial intelligence, and the increased number, sophistication and activities of perpetrators of cyber-attacks. Since the techniques used to obtain unauthorized access to or to sabotage IT systems change frequently and are often not recognized until after they are launched against a target, we may be unable to anticipate these techniques or to implement adequate preventative measures. A major cyber incident could result in significant expenses to investigate and repair security breaches or system damage and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to our reputation and customer relationships. We maintain and update a cybersecurity program to safeguard our IT systems, including those that run and connect to IT systems that run our natural gas liquefaction and export facilities. Failure to continue to do so effectively could expose our IT systems to increased risk of a successful cyber-attack.

We are also reliant on the security practices of our third-party service providers, business partners, vendors, and suppliers, which may be outside of our direct control. These third parties, and the services provided by these third parties, which may include cloud-based services, are subject to the same risk of experiencing, and have experienced, outages, other failures and security breaches described above. IT systems provided by third parties on which we rely also may be difficult to integrate with other tools due to their complexity, resulting in high data inconsistency and incompatibility. If these third parties fail to adhere to adequate security practices, or experience a breach of their systems, the information of our employees, consumers and business associates may be improperly accessed, used, disclosed or otherwise processed, and we may potentially be held liable, or alleged to be liable, under certain laws or contractual obligations for the acts or omissions of our third-party providers. Any loss or interruption to our IT systems or the services provided by third parties could adversely affect our business, financial condition and results of operations.

We maintain property and casualty insurance that may cover certain damage caused by potential cybersecurity incidents. However, other damage and claims arising from such incidents may not be covered or may exceed the amount of any insurance available as discussed under *—Risks Relating to Our Business—We are unable* *to insure against all potential risks and may become subject to higher than expected insurance premiums. In addition, we retain certain risks as a result of insurance through our captive insurance.* As a result, a significant cyber incident involving our business or operational control systems or related infrastructure, or that of third-party pipelines with which we do business, could negatively impact our operations, result in data security breaches, impede the processing of transactions, delay financial or compliance reporting or otherwise disrupt our business. These impacts could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Changes in laws, rules or regulations relating to data privacy and security, or any actual or perceived failure by us to comply with such laws, rules and regulations, or contractual or other obligations relating to data privacy and security, could adversely impact our business.

We are, and may increasingly become, subject to various laws, directives, industry standards, rules and regulations, as well as contractual obligations, related to data privacy and security in the jurisdictions in which we operate. The regulatory environment related to data privacy and security is increasingly rigorous, with new and constantly changing requirements, and is likely to remain uncertain for the foreseeable future. These laws, rules and regulations may be interpreted and applied differently over time and from jurisdiction to jurisdiction, and it is possible that they will be interpreted and applied in ways that may have a material adverse effect on our results of operations, financial condition and cash flows.

In the United States, various federal and state regulators, including governmental agencies like the Federal Trade Commission, have adopted, or are considering adopting, laws, rules and regulations concerning personal information. Certain state laws may be more stringent or broader in scope, or offer greater individual rights, with respect to personal information than federal, international or other state laws, and such laws may differ from each other, all of which may complicate compliance efforts. A number of similar laws in other states have already taken effect or will become effective in the near future. State laws are changing rapidly and in the future Congress may pass a new comprehensive federal data protection law, which may add additional complexity, variation in requirements, restrictions and potential legal risks.

All of these evolving compliance and operational requirements impose significant costs on us, which are likely to increase over time. Any failure or perceived failure by us to comply with any applicable federal, state or similar foreign laws, rules and regulations relating to data privacy and security could result in damage to our reputation and our relationship with our customers, as well as proceedings or litigation by governmental agencies or individuals, including class action privacy litigation in certain jurisdictions, which could subject us to significant fines, sanctions, awards, penalties or judgments, operational changes, and negative publicity that could adversely affect our reputation, results of operations and financial condition.

If we are unable to obtain, maintain, protect and enforce our intellectual property rights, our business may be adversely affected.

We rely on a combination of intellectual property rights, including know-how and trade secrets, to establish, maintain and protect our intellectual property and other proprietary rights. For example, under our agreements with Baker Hughes, we own certain know-how and trade secrets relating to aspects of the liquefaction systems, including the routing of the piping and valves within the liquefaction modules and optimization of other module designs, the sharing of supporting equipment between individual liquefaction trains, and the management of mixed refrigerant in the liquefaction process.

We cannot guarantee that our efforts to obtain, maintain, protect and enforce such rights are adequate or that we have secured, or will be able to secure, appropriate permissions or protections for all of the intellectual property rights we use or rely on. Furthermore, any such intellectual property rights may be challenged, invalidated, circumvented, infringed, misappropriated or otherwise violated. Any challenge to our intellectual property rights could result in them being narrowed in scope or declared invalid or unenforceable. In addition, other parties may independently develop technologies that are substantially similar or superior to ours and we may not be able to stop such parties from using such independently developed technologies to compete with us. If we fail to adequately obtain, maintain, protect and enforce our intellectual property rights, we may lose an important advantage in the markets in which we compete. While we seek to enter into confidentiality, intellectual property assignment and non-compete agreements, as applicable, with our employees, contractors and other third parties, we may fail to enter into such agreements with all relevant parties, such agreements may not be self-executing or enforceable, and we may be subject to claims that such parties have misappropriated the trade secrets or other intellectual property or proprietary rights of their former employers or other third parties. Additionally, these agreements may not provide meaningful protection for our trade secrets and know-how in the event of unauthorized use or disclosure.

We also may be forced to bring claims against third parties to determine the ownership of what we regard as our intellectual property or to enforce our intellectual property against its infringement, misappropriation or other violation by third parties. Additionally, third parties may initiate legal proceedings alleging that we are infringing, misappropriating or otherwise violating their intellectual property rights. The outcomes of such intellectual property-related proceedings are often unpredictable. Regardless of whether any such proceedings are resolved in our favor, such proceedings could cause us to incur significant expenses and could distract our personnel from their normal responsibilities. Furthermore, our intellectual property rights and the enforcement or defense of such rights may be affected by developments or uncertainty in laws, rules and regulations related to intellectual property rights. Any of the foregoing could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Risks Relating to Ownership of Our Class A Common Stock

VG Partners has significant influence over us, including control over decisions that require their approval, which could limit your ability to influence the outcome of key transactions, including a change of control.

Our Class B common stock has ten votes per share and our Class A common stock has one vote per share. Holders of shares of our Class B common stock will vote together with holders of our Class A common stock as a single class on all matters on which stockholders are entitled to vote generally, except as otherwise required by law. As of the date of filing this Form 10-K, VG Partners owned 1,968,604,458 shares of Class B common stock or 100% of all shares of Class B common stock then outstanding. As a result, VG Partners holds approximately 97.8% of the combined voting power of our Class A common stock and our Class B common stock and is able to influence or control matters requiring approval by our stockholders, including the election of directors and the approval of mergers or other extraordinary transactions. Further, the share of combined voting power held by VG Partners may increase in the future as a result of any repurchase of outstanding Class A common stock that we may decide to pursue from time to time, or any acquisition of our Class A common stock by VG Partners or our Founders, who control VG Partners (including upon vesting or exercise of equity awards). Furthermore, under Delaware law and our amended and restated certificate of incorporation and amended and restated bylaws, VG Partners is able to take certain actions by written consent of the majority of the combined voting power of our common stock without calling a meeting of stockholders. In addition, as the holder of a majority of the combined voting power of our common stock, VG Partners currently has the sole ability to elect the board of directors. Other holders of our Class A common stock, so long as they do not own a majority of the combined voting power, have only minority voting rights on matters affecting our business.

VG Partners may have interests that do not align with the interests of our other stockholders, including with regard to pursuing acquisitions, divestitures, and other transactions that, in their judgment, could enhance their equity investment, even though such transactions might involve risks to our other stockholders. VG Partners has effective control over our decisions to enter into such corporate transactions regardless of whether others believe that the transaction is in our best interests. Such concentration of voting control may have the effect of delaying, preventing, or deterring a change of control of us, could deprive stockholders of an opportunity to receive a premium for their Class A common stock as part of a sale of us, and might ultimately affect the market price of our Class A common stock.

There is the possibility of significant fluctuations in the price of our Class A common stock.

Many factors may cause the price of our Class A common stock to fluctuate substantially, which may limit or prevent investors from readily selling their shares of our Class A common stock and may otherwise negatively affect the liquidity of our Class A common stock. These factors include:

- the ongoing development and sustainability of an active, liquid market for our Class A common stock;
- the price of LNG and natural gas;
- the completion of the regulatory approval process required to construct and operate our projects and the timing of any such completion;
- the commencement and timely completion of construction of our projects;
- our quarterly or annual earnings or those of other companies in our industry;
- actual or potential non-performance by any customer under any LNG sales contract that we may enter into;
- announcements by us or our competitors of significant contracts;
- changes in accounting standards, policies, guidance, interpretations or principles;
- market conditions in the broader stock market in general, or in our industry in particular;
- future sales of our Class A common stock;
- investor perceptions of the investment opportunity associated with our Class A common stock relative to other investment alternatives;
- the public's response to press releases or other public announcements or filings by us or third parties, including our filings with the SEC;
- regulatory developments;
- geopolitical developments;
- litigation and governmental investigations; and
- other factors described in these "Risk Factors" and elsewhere in this Form 10-K.

Accordingly, any investor may lose money or their investment in us and may be required to hold their shares for an indefinite period of time. In addition, in the past, when the market price of a stock has been volatile, holders of that stock have instituted securities class action litigation against the company that issued the stock. In particular, a putative securities class action complaint naming Venture Global, our directors and and certain of our officers was filed in the U.S. District Court for the Southern District of New York on February 17, 2025, asserting claims under Sections 11 and 15 of the Securities Act that certain statements made by the Company and certain of its officers and directors in the registration statement and prospectus for the IPO were allegedly false or misleading and seeking unspecified damages on behalf of the putative class. See *—Risk Factors—Risks Relating to Regulation and Litigation—We are involved and may in the future become involved in disputes and legal proceedings.* We could incur substantial costs defending the class action and any other lawsuit our stockholders may bring against us. Such lawsuits could also divert the time and attention of our management from our business.

The trading market for our Class A common stock may also be influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover us downgrade our stock, or if our results of operations do not meet their expectations, our stock price could decline.

If we become a United States real property holding corporation, or a USRPHC, non-U.S. shareholders may be subject to U.S. federal income tax in connection with the disposition of shares of our Class A common stock.

A non-U.S. holder of our Class A common stock not otherwise subject to U.S. federal income tax on gain from the sale or other disposition of our Class A common stock may nevertheless be subject to U.S. federal income tax with respect to such sale or other disposition if we are a USRPHC at any time within the five-year period preceding the sale or other disposition (or the non-U.S. holder's holding period, if shorter). Generally, a U.S. corporation is a USRPHC if the fair market value of its "United States real property interests," as defined in the Internal Revenue Code of 1986, as amended, or the Code, and applicable Treasury Regulations, equals or exceeds 50% of the aggregate fair market value of its worldwide real property interests and its other assets used or held for use in a trade or business. Based on the current composition of our assets, we believe that we are not currently a USRPHC. However, because (i) the determination of whether we are a USRPHC at any time depends on the fair market value of our U.S. real property relative to the fair market value of other business assets at such time, and (ii) the determination as to whether certain of our assets, including our property, plant and equipment, constitute United States real property interests, as defined in the Code, may be uncertain, there can be no assurance that we will not become a USRPHC at any point in time in the future. If we were to become a USRPHC at any point during the shorter of (i) the five-year period preceding the sale or other disposition and (ii) the non-U.S. holder's holding period, and either (1) our Class A common stock is not regularly traded on an established securities market during the calendar year in which the sale or disposition occurs or (2) the non-U.S. holder has owned or is deemed to have owned, at any time within the relevant period, more than 5% of our Class A common stock, the non-U.S. holder would be subject to tax on the net gain from the sale or other disposition under the regular graduated U.S. federal income tax rates applicable to U.S. persons and could, under certain circumstances, be subject to withholding at a 15% rate on the amount realized.

Certain provisions of our amended and restated certificate of incorporation, amended and restated bylaws and Delaware law have anti-takeover effects that could limit our ability to engage in certain strategic transactions our board of directors believes would be in the best interests of stockholders.

Certain provisions of our amended and restated certificate of incorporation and amended and restated bylaws could discourage unsolicited takeover proposals that stockholders might consider to be in their best interests. Among other things, our amended and restated certificate of incorporation and amended and restated bylaws includes provisions that, among other things:

- provide for a classified board of directors with staggered three-year terms (except that prior to the Trigger Date, our board of directors will consist of a single class of directors each serving one year terms);
- permit directors to be removed from the board of directors by our stockholders only for cause and with the affirmative vote of at least 75% of the combined voting power of our then-outstanding common stock (except that prior to the Trigger Date, directors may be removed by our stockholders with or without cause);
- do not permit cumulative voting in the election of directors, which would otherwise allow less than a majority of stockholders to elect director candidates;
- authorize the issuance of "blank check" preferred stock without any need for action by stockholders;
- limit the ability of stockholders to call special meetings of stockholders or to act by written consent in lieu of a meeting (except that prior to the Trigger Date, special meetings of stockholders may be called by stockholders holding a majority of the combined voting power of our then-outstanding common stock and shareholder actions may be taken by written consent in lieu of a meeting);
- require the affirmative vote of at least 75% of the combined voting power of our then-outstanding common stock, voting as a single class, to amend certain provisions of our certificate of incorporation (except that prior to the Trigger Date, such amendments require only the affirmative vote of a majority of the outstanding shares of common stock); and

- establish advance notice requirements for nominations for election to our board of directors or for proposing matters that may be acted on by stockholders at stockholder meetings; *provided* that, at any time when VG Partners and its permitted transferees beneficially own, in the aggregate, at least 5% of the combined voting power of our common stock, such advance notice procedure will not apply to VG Partners and its permitted transferees.

The foregoing factors, as well as the significant common stock ownership by VG Partners, could impede a merger, takeover, or other business combination or discourage a potential investor from making a tender offer for our common stock, which, under certain circumstances, could reduce the market value of our Class A common stock.

In addition, we have expressly elected not to be governed by the "Business Combination" provisions of Section 203 of the Delaware General Corporation Law, or the DGCL, until the earlier of the time at which (i) VG Partners and its permitted transferees no longer beneficially own at least 15% of the combined voting power of our then-outstanding common stock and (ii) our board of directors determines that we will be subject to Section 203 of the DGCL and gives written notice to VG Partners that VG Partners and its permitted transferees shall not be subject to Section 203 of the DGCL. Section 203 of the DGCL generally prohibits a Delaware corporation from engaging in any of a broad range of business combinations with any interested stockholder for a period of three years following the date on which the stockholder became an interested stockholder. If at any time we become subject to the provisions of Section 203 of the DGCL, these provisions will prohibit large stockholders, in particular a stockholder owning 15% or more of the outstanding voting power, from consummating a merger or combination with our company from a three-year period beginning on the date of the transaction in which the stockholder acquired in excess of 15% of our outstanding voting stock, unless this stockholder receives board approval for the transaction or $66^2/_3$% of the combined voting power of our then-outstanding common stock not owned by the stockholder approve the merger or transaction. These provisions of Delaware law may have the effect of delaying, deferring or preventing a change in control, and may discourage bids for our Class A common stock at a premium over our market price.

We cannot guarantee that we will pay further dividends on our Class A common stock in the future and, consequently, your ability to achieve a return on your investment will depend on appreciation in the price of our Class A common stock.

While we currently have declared certain cash dividends that remain payable and expect that we will declare and pay additional cash dividends on our common stock from time to time, we cannot guarantee that we will pay dividends on our Class A common stock in the future. The Company is a holding company and has no direct operations. All of our business operations are conducted through our subsidiaries. We cannot assure you that we will pay any dividend in the same amount or frequency as previous dividends, or at all, in the future. Any future dividend payments are within the absolute discretion of our board of directors and will depend on, among other things, our results of operations, working capital requirements, capital expenditure requirements, financial condition, level of indebtedness, contractual restrictions with respect to payment of dividends, business opportunities, anticipated cash needs, provisions of applicable law and other factors that our board of directors may deem relevant. Consequently, your ability to achieve a return on any purchase of our Class A common stock could depend on the appreciation of our Class A common stock. Accordingly, you should not purchase shares of our Class A common stock with the expectation of receiving cash dividends.

Further, Delaware law requires that dividends be paid only out of "surplus," which is defined as the fair market value of our net assets, minus our stated capital; or out of the current or the immediately preceding year's earnings. In addition, our ability to pay dividends is subject to a range of restrictions and limitations set forth in the instruments governing our indebtedness and preferred equity.

If we, VG Partners or certain other stockholders sell shares of our Class A common stock or are perceived by the public markets as intending to sell them, the market price of our Class A common stock could decline.

The sale of substantial amounts of shares of our Class A common stock in the public market, or the perception that such sales could occur, could harm the prevailing market price of shares of our Class A common stock. These sales, or the possibility that these sales may occur, also might make it more difficult for us to sell shares of our Class A common stock in the future at a time and at a price that we deem appropriate.

As of February 14, 2025, we had a total of 450,937,393 shares of our Class A common stock outstanding, of which 380,937,393 shares was held by our Pre-IPO Stockholders and 70,000,000 shares were sold in our IPO, and we had approximately 284,274,541 outstanding stock options (including the IPO Grants) to purchase Class A common stock. All of the shares of our Class A common stock sold in our IPO are freely tradable without restriction or further registration under the Securities Act of 1933, as amended, or the Securities Act, by persons other than our "affiliates," as that term is defined under Rule 144 of the Securities Act.

In addition, as of February 14, 2025, an aggregate of 1,968,604,458 shares of our Class B common stock was outstanding, all of which was held by VG Partners. All such Class B shares of common stock are convertible into our Class A common stock on a one-to-one basis at any time at the option of the holder thereof. VG Partners continues to be considered an affiliate following our IPO, and accordingly shares of our Class A common stock issued upon conversion of our Class B common stock may not be sold in the absence of registration under the Securities Act unless an exemption from registration is available, including the exemptions contained in Rule 144.

We, our directors and officers, and our Pre-IPO Stockholders are subject to lock-up restrictions pursuant to which, subject to certain exceptions, they may not offer, pledge, sell, contract to sell, sell any option or contract to purchase, purchase any option or contract to sell, grant any option, right or warrant to purchase, lend or otherwise transfer or dispose of, directly or indirectly, any shares of our Class A common stock or securities convertible into or exchangeable for shares of our Class A common stock (including our Class B common stock) for 180 days from January 23, 2025, except with the prior written consent of the representatives of the underwriters for our IPO. In addition, holders of options to purchase Class A common stock outstanding immediately prior to closing of our IPO (other than the IPO Grants) are subject to certain market stand-off provisions pursuant to the 2023 Plan, for 180 days from January 23, 2025, except with prior written consent of us or the underwriters. The representatives of the underwriters for our IPO, in their sole discretion, may release securities subject to the lock-up arrangements described above in whole or in part at any time. Upon the expiration of such lock-up arrangements and market stand-off provisions, all of such shares will be eligible for resale in the public market, subject, in the case of shares held by our affiliates, to volume, manner of sale and other limitations under Rule 144. Subject to the expiration or waiver of the lock-up period, VG Partners, as well as the other Pre-IPO Stockholders, will have the right, subject to certain exceptions and conditions, to require us to register their shares of Class A common stock under the Securities Act, and they will have the right to participate in future registrations of securities by us. Registration of any of these outstanding shares of common stock would result in such shares becoming freely tradable without compliance with Rule 144 upon effectiveness of the registration statement.

We have also filed a registration statement on Form S-8 under the Securities Act to register shares of our Class A common stock issuable under our outstanding stock options to purchase Class A common stock and the shares of our Class A common stock reserved for issuance under the Venture Global, Inc. 2025 Omnibus Incentive Plan. Shares registered thereunder are available for sale in the open market. If such shares of Class A common stock are sold or it is perceived that they will be sold in the public market, the trading price of our Class A common stock could decline. These sales also could impede our ability to raise future capital.

You may be diluted by the future issuance of additional Class A common stock, including in connection with our incentive plans, acquisitions, conversion of our Class B common stock, or otherwise.

As of February 14, 2025, we had approximately 3.9 billion shares of Class A common stock authorized but unissued. Our amended and restated certificate of incorporation authorizes us to issue these shares of Class A common stock and options, rights, warrants and appreciation rights relating to Class A common stock for the consideration and on the terms and conditions established by our board of directors in its sole discretion, whether in connection with incentive plans, acquisitions or otherwise.

Additionally, shares of our Class B common stock are convertible into shares of our Class A common stock on a one-for-one basis at the option of the holder. Moreover, future transfers, except for certain permitted transfers described in our amended and restated certificate of incorporation, by VG Partners of shares of Class B common stock will generally result in those shares automatically converting into shares of Class A common stock on a one-for-one basis.

Any Class A common stock that we issue, including under our existing equity incentive plans or other equity incentive plans that we may adopt in the future and the conversion of Class B common stock into Class A common stock, would dilute holders of Class A common stock.

We cannot predict with certainty the size of future issuances of shares of our Class A common stock or the effect, if any, that future issuances and sales of shares of our Class A common stock will have on the market price of shares of our common stock. Any such issuance could result in substantial dilution to our existing stockholders.

We may issue preferred stock whose terms could materially adversely affect the voting power or value of our Class A common stock.

Our amended and restated certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our Class A common stock with respect to dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our Class A common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of our Class A common stock.

If our estimates or judgments relating to our critical accounting policies are based on assumptions that change or estimates that prove to be incorrect, our results of operations could be adversely affected, which could cause the price of our Class A common stock to decline.

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in our financial statements and the accompanying notes thereto. We base our estimates on historical experience and on various other assumptions that we believe to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets, liabilities, equity, revenue and expenses that are not readily apparent from other sources. It is possible that interpretation, industry practice and guidance involving estimates and assumptions may evolve or change over time. If our assumptions change, or if actual circumstances differ from our assumptions, our results of operations may be adversely affected, which could cause the price of our Class A common stock to decline.

As a result of being a public company, we are obligated to develop and maintain proper and effective internal control over financial reporting, and any failure to maintain the adequacy of our internal control may adversely affect investor confidence in our company and, as a result, the value of our Class A common stock.

As a public company, we are required to commit significant resources and management time and attention to the requirements of being a public company, which causes us to incur significant legal, accounting and other expenses that we had not incurred as a private company, including costs associated with public company reporting requirements. We incur costs associated with the Securities Exchange Act of 1934, as amended, or the Exchange Act, the Sarbanes-Oxley Act of 2002, or the Sarbanes-Oxley Act, the Dodd-Frank Wall Street Reform and Protection Act, and related rules implemented by the Securities and Exchange Commission, or the SEC, and the NYSE, and compliance with these requirements places significant demands on our legal, accounting and finance staff and on our accounting, financial and information systems.

We are required, pursuant to Section 404 of the Sarbanes-Oxley Act, to furnish a report by management on, among other things, the effectiveness of our internal control over financial reporting for the fiscal year ending

December 31, 2025. This assessment will need to include disclosure of any material weaknesses identified by our management in our internal control over financial reporting. In addition, our independent registered public accounting firm will be required to attest to the effectiveness of our internal control over financial reporting in our Form 10-K required to be filed with the SEC for the fiscal year ending December 31, 2026. We have recently commenced the costly and challenging process of compiling the system and processing documentation necessary to perform the evaluation needed to comply with Section 404 of the Sarbanes-Oxley Act, but we may not be able to complete our evaluation, testing and any required remediation in a timely fashion once initiated. Our compliance with Section 404 of the Sarbanes-Oxley Act will require that we incur substantial expenses and expend significant management efforts. We currently do not have an internal audit group, and we will need to hire additional accounting and financial staff with appropriate internal control knowledge to compile the system and process documentation necessary to perform the evaluation needed to comply with Section 404 of the Sarbanes-Oxley Act.

During the evaluation and testing process of our internal control, if we identify one or more material weaknesses in our internal control over financial reporting, we will be unable to certify that our internal control over financial reporting are effective. We cannot assure you that there will not be material weaknesses or significant deficiencies in our internal control over financial reporting in the future. Any failure to maintain internal control over financial reporting could severely inhibit our ability to accurately report our financial condition or results of operations. If we are unable to conclude that our internal control over financial reporting are effective, or if our independent registered public accounting firm determines we have a material weakness or significant deficiency in our internal control over financial reporting, we could lose investor confidence in the accuracy and completeness of our financial reports, the market price of our Class A common stock could decline, and we could be subject to sanctions or investigations by the SEC or other regulatory authorities. Failure to remedy any material weakness in our internal control over financial reporting, or to implement or maintain other effective control systems required of public companies, could also restrict our future access to the capital markets.

We are a "controlled company" within the meaning of the NYSE rules and, as a result, qualify for exemptions from certain corporate governance requirements. If we rely on such exemptions in the future, you will not have the same protections afforded to stockholders of companies that are subject to such requirements.

VG Partners controls a majority of the voting power of our outstanding common stock, and as a result, we are a "controlled company" within the meaning of the NYSE corporate governance standards. Under the NYSE rules, a company of which more than 50% of the voting power is held by another person or group of persons acting together is a "controlled company" and may elect not to comply with certain NYSE corporate governance requirements, including the requirements that:

- a majority of the board of directors consist of independent directors;
- the nominating and corporate governance committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities;
- the compensation committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and
- there be an annual performance evaluation of the nominating and corporate governance and compensation committees.

Consistent with these exemptions, we do not have an independent compensation committee or an independent nominating and corporate governance committee. Accordingly, you may not have the same protections afforded to stockholders of companies that are subject to all of the NYSE corporate governance requirements.

Our amended and restated certificate of incorporation designates the Court of Chancery of the State of Delaware or the federal district courts of the United States of America, as applicable, as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which limits our stockholders' ability to obtain a favorable judicial forum for disputes with the Company or the Company's directors, officers or other employees.

Our amended and restated certificate of incorporation provides that, unless we consent to the selection of an alternative forum, the Court of Chancery of the State of Delaware will, to the fullest extent permitted by law, be the sole and exclusive forum for: (i) any derivative action or proceeding brought on our behalf; (ii) any action asserting a breach of fiduciary duty owed by any current or former director, officer, stockholder or employee of the Company to the Company or our stockholders; (iii) any action asserting a claim against us arising under the Delaware General Corporation Law, or the DGCL, our certificate of incorporation or our bylaws or as to which the DGCL confers jurisdiction on the Court of Chancery of the State of Delaware; or (iv) any action asserting a claim against us that is governed by the internal affairs doctrine.

These provisions do not apply to suits brought to enforce a duty or liability created by the Exchange Act. Furthermore, Section 22 of the Securities Act creates concurrent jurisdiction for federal and state courts over all suits brought to enforce any duty or liability created by the Securities Act or the rules and regulations thereunder. Accordingly, both state and federal courts have jurisdiction to entertain such claims. To prevent having to litigate claims in multiple jurisdictions and the threat of inconsistent or contrary rulings by different courts, among other considerations, our amended and restated certificate of incorporation further provides that the federal district courts of the United States of America are the exclusive forum for resolving any complaint asserting a cause or causes of action arising under the Securities Act, including all causes of action asserted against any defendant to such complaint. While the Delaware courts have determined that such choice of forum provisions are facially valid, a stockholder may nevertheless seek to bring a claim in a venue other than those designated in the exclusive forum provisions and there can be no assurance that these provisions will be enforced by a court in those other jurisdictions. In this regard, stockholders may not be deemed to have waived our compliance with the federal securities laws and the rules and regulations thereunder, including Section 22 of the Securities Act.

Any person or entity purchasing or otherwise acquiring any interest in any shares of our capital stock shall be deemed to have notice of and to have consented to the forum provision in our amended and restated certificate of incorporation. This choice-of-forum provision may limit a stockholder's ability to bring a claim in a different judicial forum, including one that it may find favorable or convenient for a specified class of disputes with the Company or the Company's directors, officers, other stockholders or employees, which may discourage such lawsuits. Alternatively, if a court were to find this provision of our amended and restated certificate of incorporation inapplicable or unenforceable with respect to one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could materially adversely affect our business, financial condition and results of operations and result in a diversion of the time and resources of our management and board of directors.

General Risk Factors

Global economic conditions, including inflation and supply chain disruptions, could continue to adversely affect our operations.

General global economic downturns and macroeconomic trends, including heightened inflation, capital market volatility, interest rate and currency rate fluctuations, and economic slowdown or recession, may result in unfavorable conditions that could negatively affect demand for our products and exacerbate some of the other risks that affect our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects. Both domestic and international markets experienced significant inflationary pressures in fiscal years 2022 and 2023 and to combat such inflation, the Federal Reserve in the U.S. and other central banks in various countries raised interest rates in response. Further interest rate increases or other government actions taken to reduce inflation could result in recessionary pressures in many parts of the world. Furthermore, currency exchange rates have been especially volatile in the recent past, and these currency fluctuations have affected, and may continue to affect, the reported value of our assets and liabilities, as well as our cash flows.

We have also experienced significant challenges in our global supply chain, including shortages in supply of materials and equipment to complete construction of our projects. While to date, we have been able to manage the challenges associated with these delays and shortages without significant disruption to our business, no assurance can be given that these efforts will continue to be successful. In addition, the deterioration of conditions in global credit markets may limit our ability to obtain, or may increase the cost of, external financing to fund our operations and capital expenditures on terms favorable to us, if at all. If we are unable to obtain adequate financing or financing on terms satisfactory to us, when we require it, we will have to significantly reduce our spending, delay or cancel construction of our projects or substantially change our corporate structure, and we might not have sufficient resources to conduct or support our business as projected, which would have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects. See *—Risks Relating to Our Projects and Other Assets—We will require significant additional capital to construct and complete certain of our projects, and we may not be able to secure such financing on time with acceptable terms, or at all, which could cause delays in our construction, lead to inadequate liquidity and increase overall costs.*

Developments related to the ongoing war between Russia and Ukraine and the ongoing conflicts in the Middle East could adversely affect our business, contracts, financial condition, operating results, cash flows, liquidity and prospects.

Russia is one of the main players in the global oil and gas markets. Accordingly, any events that can impair or enhance its ability to compete in such markets are likely to have an impact on the industry in which we operate and the operations of our projects. Since the beginning of Russia's invasion of Ukraine, sanctions have been imposed by Ukraine's allies that seek to limit Russia's ability to profit from oil and gas exports, and certain retaliatory measures have been taken by Russia in response (such as the ban on sales to certain countries). Additionally, there have been publicized threats to increase hacking activity against the critical infrastructure of any nation or organization that retaliates against Russia for its invasion. This invasion, as well as the ongoing conflicts in the Middle East, have led, are currently leading, and for an unknown period of time will continue to lead to disruptions in local, regional, national, and global markets and economies affected thereby. These disruptions caused by the invasion and such conflicts have included, and may continue to include, political, social, and economic disruptions and uncertainties and material increases in certain commodity prices that could adversely affect our business, contracts, financial condition, operating results, cash flows, liquidity and prospects.

Terrorist attacks, including cyberterrorism, or military campaigns may adversely impact our business.

A terrorism, including a cyberterrorism, or military incident affecting LNG facilities, including our projects, may result in delays in construction, which could increase the cost of completion of our projects beyond the amounts that we have estimated. See *—Risks Relating to Our Projects and Other Assets—Our estimated costs for our projects have been, and continue to be, subject to change due to various factors.* A terrorism, including a cyberterrorism, incident may also result in temporary or permanent closure of any of our projects, which could increase our costs and decrease our cash flows, depending on the duration and timing of the closure. Our operations could also become subject to increased governmental scrutiny that may result in additional security measures at a significant incremental cost to us. In addition, the threat of terrorism, including cyberterrorism, and the impact of military campaigns may lead to continued volatility in prices for natural gas that could adversely affect our business and our customers, including their ability to satisfy their obligations to us under our commercial agreements. Instability in the financial markets as a result of terrorism, including cyberterrorism, war, earthquakes and other natural or man-made disasters, pandemics, credit crises, recessions or other factors could increase the cost of insurance coverage and could also result in a significant decline in the U.S. economy and could also materially adversely affect our ability to raise capital. The continuation of these developments may subject our construction and our operations to increased risks, as well as increased costs, and, depending on their ultimate magnitude, could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Changes in tax laws or tax rulings, or the examination of our tax positions, could materially affect our financial condition and results of operations.

We are subject to various types of tax arising from normal business operations in the jurisdictions in which we operate and transact. Any changes to local, domestic or international tax laws and regulations, or their interpretation and application, including those with retroactive effect, could affect our tax obligations, profitability and cash flows in the future. In addition, tax rates in the various jurisdictions in which we operate may change significantly due to political or economic factors beyond our control. Our existing corporate structure and intercompany arrangements have been implemented in a manner we believe is in compliance with current prevailing tax laws. In addition, the taxing authorities in the United States and other jurisdictions where we do business regularly examine income and other tax returns and we expect that they may examine our income and other tax returns. The ultimate outcome of these examinations cannot be predicted with certainty. We continuously monitor and assess proposed tax legislation that could negatively impact our business.

The Inflation Reduction Act, enacted on August 16, 2022, includes the implementation of a new 15% corporate alternative minimum tax, or the CAMT, on adjusted financial statement income for applicable corporations, effective for tax years beginning after December 31, 2022. CAMT is a novel and new approach for calculating corporate tax liability. Many unanswered questions remain on how the operative rules for CAMT will be implemented and interpreted. The CAMT may lead to volatility in our cash tax payment obligations, particularly in periods of significant commodity, currency or financial market variability resulting from potential changes in the fair value of our derivative instruments.

We face risks related to the uncertainty regarding the future of international trade agreements and the United States' position on international trade.

Certain policies and statements of the prior and current Trump administration have given rise to uncertainty regarding the future of international trade agreements and the United States' position on international trade. For example, the first Trump administration imposed tariffs on a range of products from China, which led China to also impose tariffs on certain U.S. goods in retaliation, including a 25% tariff on U.S. LNG imports. The current Trump administration has indicated that they intend to impose or threatened to impose additional tariffs on other countries (such as Canada, Colombia and Mexico), and has imposed a 10% tariff on the import of Chinese goods. In addition, on February 10, 2025, the Trump administration announced the imposition of a 25% tariff on the import of steel and aluminum to the United States, no matter the origin, which will go into effect on March 12, 2025. The imposition and or threat of tariffs by the United States has in the past, and may continue to in the future, result in retaliatory tariffs imposed on U.S. businesses from any countries affected by such tariffs. Additionally, the imposition of retaliatory tariffs by any nation against the U.S. could have a material adverse effect on trade between the U.S. and other nations, as well as on the cost of goods for U.S. companies and consumers. The impact of any such tariffs remains uncertain and accordingly is not reflected in our current project cost estimates. However, the impositions of such tariffs could negatively affect demand for our products and our project cost estimates, particularly construction costs that may relate to foreign-sourced materials such as steel and aluminum, and also exacerbate some of the other risks that affect our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity.

We also face potential exposure to evolving U.S. tariff standards, and potential retaliatory international tariffs that may be imposed by other countries in response to U.S. tariffs, primarily on LNG exports and construction-related materials, systems, piping and commodities (e.g. cement, copper, nickel and steel). China's decision to implement a 15% tariff on coal and LNG products in response to US tariff initiatives may potentially impact our ability to sell commissioning and short-term LNG cargoes to China. In addition, given the rapidly evolving tariff landscape, we cannot anticipate the breadth of potential tariffs that may be announced and/or implemented on internationally sourced components and commodities used to construct our LNG facilities. As a result, the impact of any such tariffs remains uncertain and accordingly is not reflected in our current project cost estimates. However, the imposition of any such tariffs could negatively affect demand for our products and our project cost estimates, and also exacerbate some of the other risks that affect our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity.

As of December 31, 2024, we had entered into long term, post-COD SPAs for an aggregate of 9.5 mtpa with Chinese customers across all of our projects. Any future changes to the United States' trade relationship with China or other major LNG importing nations, including through the imposition of further tariffs, could have an adverse impact on such SPAs and our ability to market the remaining production capacity of our projects, by reducing demand from such customers for U.S. LNG exports. Moreover, the uncertainty regarding the policies of the current

Trump administration with respect to the future of trade partnerships and relations, including the possibility of additional or increased tariffs, may reduce our competitiveness in countries that may be affected by those policies, such as China, whether or not the second Trump administration ultimately takes any such actions. Any of these factors could adversely affect our ability to market the remaining production capacity of our projects, which could have a material adverse effect on the viability of our projects and on our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

Our ability to use our net operating losses to offset future taxable income may be subject to certain limitations.

As of December 31, 2024, we have accumulated federal net operating loss, or NOL, carryforwards of $6.7 billion with an indefinite carryforward period. We additionally had accumulated state net operating loss carryforwards of approximately $3.9 billion, of which $42 million will expire by 2037. Under the current tax law, federal NOLs incurred in taxable years beginning after December 31, 2017, can be carried forward indefinitely, but the deductibility of such federal NOLs in taxable years beginning after December 31, 2020 is limited to 80% of taxable income. These federal and state NOLs may be available to offset income tax liabilities in the future. In addition, we may generate additional NOLs in future years. NOLs may be limited by separate return limitation year, or SRLY, rules. These rules generally limit the use of NOL carryforwards to the amount of taxable income that the NOL producing entity contributes to consolidated taxable income during the year. Of the federal NOL carryforward amount stated earlier, $42 million is currently subject to the SRLY rules. NOLs subject to the SRLY limitations may also be subject to Section 382 limitations described below.

In general, under Section 382 of the Code, or Section 382, a corporation that undergoes an "ownership change" is subject to limitations on its ability to utilize its pre-change NOLs to offset future taxable income. For this purpose, an ownership change generally means a more than 50 percentage point change in the ownership of a corporation by one or more shareholders or specified groups of shareholders, each of which owns 5% or more of the corporation (determined after the application of certain attribution and grouping rules) over a three-year period. Although we do not believe that any of our NOLs are currently subject to limitation under Section 382, future changes in our stock ownership could result in an ownership change under Section 382, which could limit our ability to use our existing or future NOLs to offset future taxable income.

The outbreak of any infectious diseases or other illness could adversely impact our business, contracts, financial condition, operating results, cash flow, financing requirements, liquidity and prospects.

We are subject to risks related to outbreaks of infectious diseases. The extent to which an outbreak of an infectious disease or other illness could impact our business, operations and financial results depends on numerous factors that we cannot accurately predict, including: the duration and scope of any infectious disease; governmental, business and individuals' actions taken in response to any infectious disease and the associated impact on economic activity; the effect on the level of global demand for natural gas; geopolitical developments in the oil and gas markets; our ability to procure materials and services from third parties that are necessary for the operation of our business; the effect on the labor market, including worker shortages or related to supply chain disruptions; our ability to provide our services, including as a result of travel restrictions on our employees and employees of third parties that we utilize in connection with our services; the potential for key executives or employees to fall ill; and the ability of our customers to pay for our services if their businesses suffer as a result of any infectious disease.

We cannot estimate the magnitude and duration of potential social, economic and labor instability as a direct result of any infectious disease or pandemic. Should any of these potential impacts continue for an extended period of time, it will have a negative impact on the demand for our services and a material adverse effect on our financial position and results of operations. Moreover, the foregoing factors may also have the effect of heightening some of the other risk factors described herein.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

Cybersecurity Risk Management

Cybersecurity risk management is a critical priority for our Company, and we recognize the increasing sophistication and prevalence of cyber threats globally. We face ongoing risks related to cyber-attacks, data breaches, and system disruptions, which could materially impact our operations, financial results, and reputation. These risks encompass a broad spectrum, including potential disruptions to our critical energy infrastructure, compromise of confidential or sensitive operational and commercial data, theft of intellectual property, and financial losses resulting from business interruption, remediation costs, and regulatory penalties. Our cybersecurity program is designed to align with industry-leading standards, including the widely recognized NIST Cybersecurity Framework (CSF), and provides a framework for handling cybersecurity threats and incidents, including threats and incidents associated with the use of services provided by third-party service providers. This framework guides our approach to cybersecurity risk management through five core principles: Identify, Protect, Detect, Respond, and Recover, which enable what we believe is a comprehensive and proactive security posture. Our cybersecurity program is comprised of policies, procedures, controls, and tools designed to mitigate cybersecurity risks. We maintain a risk assessment process which includes steps for identifying cybersecurity threats, assessing the severity and impact, identifying the source of a cybersecurity threat, including whether the cybersecurity threat is associated with a third-party service provider, implementing cybersecurity countermeasures and mitigation strategies and informing management and our board of directors of material cybersecurity threats and incidents. This program includes preventative controls, continuous monitoring, incident detection and response capabilities, and regular security assessments and updates. Our cybersecurity team also engages third-party security experts for risk assessment and system enhancements.

We are committed to complying with all applicable cybersecurity regulations, including those relevant to the operation of US LNG export terminals and natural gas pipelines. Our facilities and maritime operations are subject to the Maritime Transportation Security Act, and we are dedicated to meeting its applicable cybersecurity-related requirements as enforced by the US Coast Guard and relevant guidance from agencies such as the Cybersecurity and Infrastructure Security Agency. We are committed to continuously enhancing our cybersecurity defenses and incident response plans to adapt to the evolving threat landscape and protect our assets and stakeholders. Given the nature of our operations, a particular area of focus is the security of our Operational Technology and Industrial Control Systems, which are essential for the safe and continuous operation of our liquefaction plants, terminals, and related infrastructure. Protecting these systems from cybersecurity threats is paramount to prevent operational disruptions, ensure safety, and maintain the reliability of our energy delivery.

Our board of directors has overall oversight responsibility for our risk management, and, following our IPO, delegates cybersecurity risk management oversight to the audit committee. The audit committee is responsible for ensuring that management has processes in place designed to identify and evaluate cybersecurity risks to which we are exposed and implement processes and programs to manage cybersecurity risks and mitigate cybersecurity incidents. The audit committee reports material cybersecurity risks to our full board of directors. Cybersecurity governance is overseen by senior management, which is responsible for identifying, considering and assessing material cybersecurity risks on an ongoing basis, establishing processes to ensure that such potential cybersecurity risk exposures are monitored, putting in place appropriate mitigation measures and maintaining cybersecurity programs.

Leadership for our cybersecurity program is provided by our Chief Information Officer, or CIO, who receives reports from our cybersecurity team and monitors the prevention, detection, mitigation, and remediation of cybersecurity incidents. Our CIO is a seasoned executive with over 25 years of experience in Information Technology, including 18 years in cybersecurity leadership roles specifically within the energy industry. The CIO's expertise is further underscored by prior service on the American Gas Association's Distribution Natural Gas Information Sharing and Analysis Center and as a former President of Oregon's InfraGard chapter, a partnership between the FBI and the private sector. Notably, the CIO also serves as our Chief Information Security Officer and is supported by a cybersecurity team with many years of experience led by a Vice President of Cybersecurity.

Management, including the Chief Financial Officer and CIO, will update the audit committee on our cybersecurity programs, material cybersecurity risks, program assessments and mitigation strategies. The CIO will provide periodic cybersecurity reports that cover these topics and industry developments.

Despite our efforts, we cannot eliminate all risks from cybersecurity threats, or provide assurances that we have not experienced an undetected cybersecurity incident. For more information about these risks, please see Item 1A.—*Risk Factors*—*Risks Relating to Intellectual Property, Data Privacy and Cybersecurity—Hostile cyber intrusions, or other issues with our information technology, could severely impair our operations, lead to the disclosure of confidential information, damage our reputation and otherwise have a material adverse effect on our business* of this Form 10-K.

ITEM 2. PROPERTIES

In the aggregate, as of December 31, 2024, we owned, leased or had an option to lease or purchase nearly 6,100 acres of land on the United States Gulf Coast, upon which we are developing our liquefaction and export projects.

For the Calcasieu Project, we entered into ground leases with various landowners in Cameron Parish, Louisiana, for up to 70 years. These ground leases cover approximately 432 acres of land for an initial term of 30 years, with four 10-year extensions exercisable at our option. The Calcasieu Project site also benefits from eight separate material offloading sites that are situated on the east side of the Calcasieu Ship Channel, have access to the primary access road to the project site and are adjacent to the Calcasieu Project and the CP2 Project sites. They range from approximately three to ten acres, and we are using these offloading sites to offload equipment and building materials during construction. These offloading sites are held under ground leases by one of our subsidiaries and we have access to these sites under access license agreements with that subsidiary.

We also entered into a 30-year lease with the Plaquemines Port Harbor and Terminal District, covering the 630 acres of land on which the Plaquemines Project is located. This lease may be extended at our option for up to four additional 10-year terms, up to 70 years in the aggregate. We also have lease option agreements to lease up to an additional approximately 1,100 acres of adjacent land that can be used for the potential bolt-on expansion for the Plaquemines Project and Delta Project under substantially similar terms as our existing lease for the Plaquemines Project.

We entered into various 30-year leases covering approximately 1,130 acres of land on which the CP2 Project will be located or adjacent to. We acquired fee ownership to approximately 27 acres of the project site in 2024.

We also entered into a 30-year lease covering 840 acres of land for the CP3 Project. This lease may be extended at our option for up to four additional 10-year terms, up to 70 years in the aggregate.

We own the office space in Arlington, VA where our principal executive offices are located. In addition, we lease office space in Houston, TX; Singapore; London, England; and Tokyo, Japan. These office leases expire or become subject to renewal clauses at various dates.

ITEM 3. LEGAL PROCEEDINGS

We are involved, and in the future may become involved, in various claims, lawsuits, and other proceedings incidental to the ordinary course of our business from time to time. For example, the Calcasieu Project is currently in arbitration proceedings with seven SPA customers for the Calcasieu Project. See Item 1A.—*Risk Factors*—*Risks Relating to Regulation and Litigation—We are involved and may in the future become involved in disputes and legal proceedings* and Item 1A.—*Risk Factors*—*Risks Relating to Regulation and Litigation—If we are unsuccessful in any current or potential future arbitration proceedings with customers, the amounts that we are required to pay may be substantial or certain of our post-COD SPAs may be terminated, which may lead to an acceleration of all our debt for the relevant project* of this Form 10-K. In addition, as of December 31, 2024 certain of our former employees filed proceedings, including in Virginia federal court, seeking aggregate damages of approximately $214 million with respect to alleged breaches of certain stock option grant agreements and related matters. Further, a putative securities class action complaint naming Venture Global, our directors and certain of our officers was filed in the U.S. District Court for the Southern District of New York on February 17, 2025. The complaint asserts claims under Sections 11 and 15 of the Securities Act on behalf of a putative class of all persons and entities who purchased or otherwise acquired our Class A common stock pursuant and/or traceable to the registration statement for the IPO. It contends that certain statements made by the Company and certain of its officers and directors in the registration statement and prospectus for the IPO were allegedly false or misleading and seeks unspecified damages on behalf of the putative class. See Item 1A.—*Risk Factors*—*Risks Relating to Regulation and Litigation—We are involved and may in the future become involved in disputes and legal proceedings* of this Form 10-K.

Further, from time to time, we may be a party to various administrative, regulatory or other legal proceedings, such as various proceedings before FERC related to our projects. See Item 1A.—*Risk Factors*—*Risks Relating to Regulation and Litigation—We are involved and may in the future become involved in disputes and legal proceedings* of this Form 10-K.

We are required to assess the likelihood of any adverse judgments or outcomes related to these legal contingencies, as well as potential ranges of probable or reasonably possible losses. We accrue for litigation and claims when it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. The determination of the amount of any losses to be recorded or disclosed as a result of these contingencies is based on a careful analysis of each individual exposure with, in some cases, the assistance of outside legal counsel. There can be no assurance that any accrued liabilities will be adequate to cover all existing and future claims or that we will have the liquidity to pay such claims as they arise. If the Calcasieu Project is unsuccessful in defending against certain claims by our post-COD SPA customers for the Calcasieu Project described above, the amounts it could be required to pay could be substantial, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Other than such foregoing claims, as of the date hereof, there are no pending or threatened legal claims or proceedings, individually or in the aggregate, which we believe could have a material adverse effect on our business or financial condition. For more information, see Item 8.—*Financial Statements and Supplementary Data*—*Note 15 – Commitments and Contingencies* of this Form 10-K.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information

Our Class A common stock has traded on the New York Stock Exchange under the symbol "VG" since January 24, 2025. Prior to this date, there was no public trading market for our Class A common stock. There is no public trading market for our Class B common stock.

Holders

As of February 14, 2025, we had approximately 450,937,393 shares of Class A common stock outstanding held by twelve record owners. As of February 14, 2025, there was one holder of record of our Class B common stock. This does not include the number of stockholders that hold shares in "street-name" through banks or broker-dealers.

Dividend Policy

On September 13, 2024, our board of directors declared the payment of cash dividends to our stockholders in an aggregate amount of $160 million to be paid, subject to applicable law, on a pro rata basis to holders of record of our outstanding common stock on the applicable record dates in four equal dividend payments of $40 million on the last business day of four consecutive calendar quarters. The purpose of this cash dividend is to distribute profits to our stockholders.

The first two such dividend payments were made on September 30, 2024 and December 31, 2024, to holders of our outstanding common stock of record as of September 13, 2024 and December 12, 2024, respectively. We expect to pay the remaining two dividend payments on the last business day of each of the calendar quarters ending March 31, 2025 and June 30, 2025, on a ratable basis to holders of our outstanding common stock, as of a record date to be determined by us and announced prior to the applicable dividend payment date. The record date for the March 31, 2025, dividend payment is March 10, 2025. We expect that the record date for the June 30, 2025 dividend payment will be following the filing of this Form 10-K.

Our Second Amended and Restated Certificate of Incorporation authorizes Class A common stock and Class B common stock and provides that holders of our Class A common stock and holders of our Class B common stock will be treated equally and ratably on a per share basis with respect to any dividends (unless different treatment of the shares of a class is approved by the affirmative vote of the holders of a majority of the outstanding shares of the applicable class of common stock treated adversely, voting separately as a class). Accordingly, holders of shares of Class A common stock in our IPO that are holders on the applicable record date for each of the remaining two dividend payments of the declared dividend will be entitled to receive such dividend payments.

We currently expect that we will declare and pay additional cash dividends on our common stock from time to time. However, we cannot assure you that we will pay any dividend in the same amount or frequency as previous dividends, or at all, in the future. Any future dividend payments are within the absolute discretion of our board of directors and will depend on, among other things, our results of operations, working capital requirements, capital expenditure requirements, financial condition, level of indebtedness, preferred equity obligations, contractual restrictions with respect to payment of dividends, general economic business conditions, industry practice, business opportunities, anticipated cash needs, provisions of applicable law and other factors that our board of directors may deem relevant. Consequently, your ability to achieve a return on your investment could depend on the appreciation of our Class A common stock. Further, Delaware law requires that dividends be paid only out of "surplus," which is defined as the fair market value of our net assets, minus our stated capital; or out of the current or the immediately preceding year's earnings. In addition, our ability to pay dividends is subject to a range of restrictions and limitations set forth in the instruments governing our indebtedness and preferred equity. For more details, see Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations*—*Liquidity and*

Capital Resources, Item 1A.—*Risk Factors*—*Risks Relating to Our Indebtedness and Financing—Certain of our debt agreements impose significant operating and financial restrictions on our subsidiaries, and the preferred equity of our subsidiaries also gives the holders certain consent rights, all of which may prevent us from capitalizing on business opportunities or paying dividends to the Company* and Item 1A.—*Risk Factors*—*Risks Relating to Our Indebtedness and Financing—As a holding company, the Company depends on the ability of its subsidiaries to transfer funds to it to meet its obligations* of this Form 10-K.

Recent Sales of Unregistered Securities

None.

Use of Proceeds from Registered Securities

On January 27, 2025, we closed our IPO in which we issued and sold 70 million shares of Class A common stock. The shares sold in our IPO were registered under the Securities Act pursuant to our Registration Statement on Form S-1, as amended (File No. 333-283964) which was declared effective by the SEC on January 23, 2025. Our shares of Class A common stock were sold at an initial public offering price of $25.00 per share, which generated net proceeds of approximately $1.7 billion after deducting underwriting discounts and commissions of $70 million. We estimated that we incurred offering expenses of approximately $10 million. We expect to use the proceeds (net of underwriting discounts) from our IPO to support the continued growth and development of our business, increase our financial flexibility, and establish a public market for our Class A common stock, as well as for general corporate purposes, including, but not limited to, funding our expected pre-FID capital expenditures with respect to the CP2 Project, the CP3 Project and the Delta Project, any bolt-on expansions that we may develop, our continuing operations, our LNG tanker milestone payments, and our pipeline development projects.

There has been no material change in our planned use of net proceeds from our IPO as described under the heading "Use of Proceeds" in our final prospectus, filed with the SEC on January 23, 2025 pursuant to Rule 424(b)(4) relating to our Registration Statement.

Goldman Sachs & Co. LLC, J.P. Morgan and BofA Securities acted as joint lead book-running managers. ING, RBC Capital Markets, Scotiabank, Mizuho, Santander, SMBC Nikko, MUFG, BBVA, Loop Capital Markets, Natixis, Deutsche Bank Securities, Wells Fargo Securities and Truist Securities acted as joint book-running managers for the offering. National Bank of Canada Financial Markets, Raymond James, Regions Securities LLC, Guggenheim Securities and Tuohy Brothers acted as co-managers for the offering.

Purchase of Equity Securities by the Issuer and Affiliated Purchasers

None.

ITEM 6. [RESERVED]

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our audited consolidated financial statements and the accompanying notes thereto, included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K. In addition to historical consolidated financial information, the following discussion contains forward-looking statements that reflect our plans, estimates, and beliefs that involve significant risks and uncertainties. Our actual results could differ materially from those discussed in the forward-looking statements. Factors that could cause or contribute to those differences include those discussed below and elsewhere in Item 1A.—*Risk Factors* and *Cautionary Statement Regarding Forward-Looking Statements* of this Form 10-K.

In September 2023, we engaged in a series of reorganization transactions, or the Reorganization Transactions, that ultimately resulted in Venture Global becoming the principal parent company of our entire enterprise. See Item 8.—*Financial Statements and Supplementary Data*—*Note 2 – Summary of Significant Accounting Policies* of this Form 10-K for further information.

On January 27, 2025, the Company effectuated an approximately 4,520.3317-for-one forward stock split of its Class A common stock in connection with its IPO which was completed on January 27, 2025. All Class A common stock share and per share amounts in these consolidated financial statements have been retroactively adjusted to reflect the impact of the Stock Split. See Item 8.—*Financial Statements and Supplementary Data*—*Note 25 – Subsequent Events* for further discussion of the IPO.

Executive Summary

Our LNG Projects

Calcasieu Project. In 2024, production and sales of LNG from our initial LNG export facility remained ongoing, although not at full nameplate capacity levels, while we continued to address significant remaining work related to commissioning, carryover completions, rectification, reliability testing, and other incomplete aspects of the facility. Sales from our Calcasieu Project commenced in March 2022. LNG cargos exported in 2024 totaled 140 (504.5 TBtu of LNG) compared to 143 (506.0 TBtu of LNG) in 2023.

Plaquemines Project. In December 2024, we first produced LNG from our second LNG export facility, and as of December 31, 2024, we exported one cargo from the Plaquemines Project, which was in-transit to our customer. In December 2024, a portion of the facility's assets, representing $11.4 billion of costs, were placed in service in accordance with GAAP. As of December 31, 2024, physical construction of the Plaquemines Project was ongoing and the project's commissioning program remained underway. In 2024, we incurred $9.3 billion of project costs, the majority of which were capitalized.

CP2 Project. In 2024, we significantly advanced the development of our third LNG project, amidst a fluctuating political and regulatory environment. During the year, we incurred $2.7 billion of project costs primarily associated with engineering and design, equipment procurement, and off-site manufacturing work, a portion of which was capitalized and a portion of which were expensed. In 2024, we issued purchase orders and notices to proceed thereunder to Baker Hughes for both the liquefaction train and power island systems for Phase 2 of the project, among other development and procurement activities. We also continued to see change in regards to the CP2 Project's regulatory landscape, as discussed below:

- *FERC authorization*. In June 2024, we received authorization from FERC to site, construct and operate the CP2 Project. In July 2024, a group of opponents, composed mostly of environmental groups, filed a request for rehearing of FERC's authorization. In November 2024, FERC issued an order on rehearing that, among other things, (i) generally rejected the opposition's arguments, (ii) stated that FERC would prepare a supplemental EIS to further address air impacts of certain emissions, and (iii) that FERC will address the emissions topic in a future order. In addition, FERC announced that, due to its initiation of supplemental environmental review, it will not issue authorizations to proceed with construction until the

Commission issues a further merits order. In February 2025, FERC prepared its draft supplemental EIS which reaffirmed that CP2 Project emissions impacts are "not significant".

- *DOE non-FTA authorization*. In January 2024, the Biden administration announced a temporary pause on approvals from the DOE to export natural gas to Non-FTA Nations. In January 2025, President Trump issued an Executive Order that, among other things, directed the DOE to resume reviews of such export applications.

Our Sources of Capital. In July 2024, VGLNG issued $1.5 billion of 7.000% senior secured notes maturing January 2030. In September 2024, VGLNG issued 3 million shares of 9.000% Series A Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock for gross proceeds of $3.0 billion. In early 2025, we completed our IPO, issuing and selling 70 million shares of our Class A common stock at a public offering price of $25.00 per share. In connection with the IPO, we effectuated a 4,520.3317-for-one forward stock split of our Class A common stock, which has been retrospectively incorporated into this Form 10-K, as applicable.

Our Strategic Advancements. In July 2024, we took delivery of our first two of nine LNG tankers that we have contracted to construct and/or acquire. In addition, in 2024, we executed two medium-term and two short-term charters for additional LNG tankers, bringing our shipping portfolio to a total of thirteen vessels. In 2024, eight of our cargos from LNG produced by the Calcasieu Project and the Plaquemines Project were sold or in-transit on as delivered terms utilizing our owned or chartered LNG tankers. In 2024, we signed an agreement for 1 mtpa of regasification capacity, or approximately 12 cargos annually, at the Alexandroupolis LNG regasification terminal in Greece for five years, which is expected to begin in October 2025.

LNG Market Environment. In 2024, average LNG prices experienced a significant decline compared to 2023 as a result of various supply and demand factors, including high inventories in Europe and relatively stable natural gas supply conditions. In the U.S., the Henry Hub natural gas spot price averaged $2.25 per MMBtu in 2024 a decline of 11% from 2023. In Europe, the Title Transfer Facility, or TTF, price averaged $10.89 per MMBtu in 2024, a decline of 15% from 2023. The Japan-Korea-Marker, or JKM, price, a key benchmark for LNG in East Asia, averaged $11.91 per MMBtu in 2024, a decline of 14% from 2023. See Item 1A.—*Risk Factors*—*Risks Relating to Our Business—Our ability to generate proceeds from sales of commissioning cargos is subject to significant uncertainty and volatility in such proceeds, given significant volatility in spot-market prices* of this Form 10-K.

Our Financial Results. Our net income for the year ended December 31, 2024 decreased $1.9 billion, from $3.6 billion in 2023 to $1.7 billion in 2024, primarily due to the decrease in income from operations of $3.1 billion, from $4.9 billion in 2023 to $1.8 billion in 2024. This decrease was primarily due to a reduction in the weighted average price of LNG commissioning sales in 2024 compared to 2023. The impact on net income attributable to volumes sold was less significant between the periods.

	Years ended December 31,		
	2024	2023	2022
LNG volumes exported(1)			
Cargos	141	143	94
TBtu	508.4	506.0	329.5
LNG volumes sold (TBtu)(2)	500.6	509.6	329.5
Weighted average price of LNG volumes sold (per MMBtu)(3)	$ 9.89	$ 15.43	$ 25.35

(1) Volumes that departed our LNG production facilities.
(2) Delivered to customer and recognized in results of operations.
(3) Contracted spot and/or forward prices, generally consisting of a liquefaction fee and commodity charge.

Key Factors Affecting Results of Operations

The key factors affecting our results of operations and financial performance are as follows:

Sales of LNG during commissioning of our projects. We aim to generate cash proceeds from the sale of LNG produced during the commissioning phase of each of our projects. Our ability to generate such cash proceeds, and the amount of any such cash proceeds, will depend primarily on the duration of the commissioning phase for each of our projects, the volume of LNG that we are able to produce during the commissioning phase, our ability to negotiate sales of LNG produced during the commissioning phase, as well as the market price for LNG at the time of such sales. As a result, the amount of cash proceeds we are able to generate from such sales of commissioning cargos will likely differ from period to period and from project to project, and such differences could be material.

Sales of LNG post-COD of our projects. We aim to generate cash proceeds from the sale of LNG produced after COD for each of our projects under a combination of long-term 20-year post-COD SPAs as well as short- and medium-term post-COD SPAs to optimize the average fixed facility charge across our SPAs. Further, to the extent our projects generate excess capacity relative to the nameplate capacity, we expect to sell such excess capacity as described below. None of our projects have achieved COD as of the date of this Form 10-K. Our ability to generate cash proceeds from such sales, and the amount of any such cash proceeds that we are able to generate, will be contingent upon achieving COD at each of our projects, and will vary depending on the following key factors:

- *Contract price under our SPAs.* Our existing post-COD SPAs will require our export customers to pay us a fixed facility charge per MMBtu, plus a variable commodity charge per MMBtu, in an amount equal to, depending on the applicable SPA, 115% or more of the Henry Hub gas price. The fixed facility charge varies across our post-COD SPAs and a portion of the fixed facility charge will be adjusted for inflation. For any additional post-COD SPAs that we may enter into in the future which include a fixed facility charge, that amount will be based on several factors, including market conditions at the time we enter into the relevant contract. Final terms for any additional post-COD SPAs we may enter into in the future will not be known until those contracts are executed and will impact our future revenue, as well as our operating margins.
- *Henry Hub gas price.* As described above, the variable commodity charge under our post-COD SPAs requires our customers to pay 115% or more of the Henry Hub gas price per MMBtu, which is intended to cover the price of the feed gas and gas transportation costs, and is also intended to cover certain of our operating expenses and partially adjust for inflation. We anticipate that any additional post-COD SPAs we enter into in the future will similarly require our export customers to pay a similar variable commodity charge. As a result, changes in the Henry Hub gas price will impact our future revenue, as well as our operating margins. In addition, there may be differences, and such differences may be material, between the actual price we pay for feed gas and the Henry Hub gas price used to calculate the variable commodity charges payable by our customers under the relevant post-COD SPAs, which could affect our operating margins.
- *Sales of uncommitted and excess LNG.* We intend to market and sell any uncommitted LNG and any excess capacity through our wholly owned subsidiary, VG Commodities, which manages our shipping business, providing the flexibility to optimize pricing for such sales. Our ability to generate cash proceeds from such sales, and the amount of any such cash proceeds that we are able to generate, will depend primarily on the volume of LNG that has been contracted under post-COD SPAs and the amount of LNG that we are able to produce at any project in excess of the nameplate capacity, our ability to negotiate sales of such uncommitted and excess LNG, as well as the market price for LNG at the time of such sales or the terms of any SPA we are able to negotiate with respect to such sales. As a result, the amount of cash proceeds we are able to generate from such sales of uncommitted and excess LNG, if any, will likely differ from period to period and from project to project, and such differences could be material.

Cost of feed gas. The direct costs of purchasing, transporting and converting natural gas to LNG for sale to our customers are the main component of our cost of sales. Under the post-COD SPAs and substantially all of the commissioning cargo sales that we have executed to date, our export customers pay a fixed facility charge (which includes a CPI-linked component) per MMBtu, plus a variable commodity charge per MMBtu, in an amount equal to, depending on the applicable SPA, 115% or more of the Henry Hub gas price, which is intended to cover the price of the feed gas and gas transportation costs, and is also intended to cover certain of our operating expenses and partially adjust for inflation. If we are successful in producing and selling excess LNG produced by our projects, we expect our cost of sales to increase as we will be required to purchase more feed gas to produce more LNG.

Project costs and expenses. We currently have five projects in various stages of development. We expect our development, construction and commissioning expenses for any particular project to increase significantly as we approach and commence the construction phase, and we expect these expenses will continue to be significant until the commissioning phase has been completed and the relevant project reaches its COD. Moreover, our project costs may be higher than we currently estimate due to many factors outside of our control, which could lead to higher development, construction and commissioning expenses for our projects. In addition, we expect to increase our project-dedicated staff as we progress towards the commencement of construction of the CP2 Project, the CP3 Project and the Delta Project and when we subsequently commence operation at our facilities. As a result, we anticipate that operating and maintenance expenses will increase significantly as we approach commissioning and operation of our projects (as was the case for the Calcasieu Project). We outsource certain major equipment maintenance activities under long-terms service arrangements, but our various operating subsidiaries are responsible for performing day-to-day operations and maintenance work for our projects. See Item 1.—*Business*—*Major Consultants and Contractors* of this Form 10-K for more information. Once one of our projects has commenced full commercial operations, we anticipate that the timing of the operating and maintenance costs under the long-term service arrangements for that project will be relatively predictable, subject to inflation, and will generally increase during periods in which regularly scheduled or other maintenance is performed. Increases in operating and maintenance expenses would impact our operating margins. Further, we anticipate that insurance premiums for LNG projects may increase due to losses and claims that have arisen or been experienced in respect of other unrelated projects in other regions, or losses and claims that are large enough to impact the broader insurance market even if an LNG project is not involved.

Effective tax rates and regulations. We utilize various tax incentive programs the State of Louisiana offers, including the industrial tax exemption, to offset local and state taxes that would otherwise be payable. However, the industrial tax exemption will expire after two 5-year periods, which would begin on the last day of the tax year in which the Calcasieu Project, the Plaquemines Project and the CP2 Project assets, as applicable, are placed in service from an accounting perspective, and afterwards ad valorem taxes may be levied against our properties. We anticipate similar tax exemptions will be available for the CP3 Project and the Delta Project, although any such exemptions may only be available at lower rates. The future rates at which any taxes (including ad valorem taxes, inventory taxes, franchise taxes and utility taxes) will be levied against us will impact our operating margins.

Inflation. Inflation remains a variable factor in the United States economy, and it may impact our operating margins and results of operations in the future. In particular, we anticipate that the post-COD SPAs that include a fixed facility charge and that we enter into will only be partially adjusted for inflation over the contract term, as is the case with our existing post-COD SPAs as described above. In addition, we anticipate that our operating costs will experience inflationary pressure over time, and the commodity charge we charge our customers for recovery of these costs is based on the price of natural gas per MMBtu. We also expect to experience inflation with respect to the cost of equipment and personnel necessary to develop, construct and operate our projects. See Item 1A.—*Risk Factors*—*Risks Relating to Our Projects and Other Assets—Our estimated costs for our projects have been, and continue to be, subject to change due to various factors* and Item 1A.—*Risk Factors*—*Risks Relating to Our Business—We and our contractors, including our EPC contractors, may experience increased labor costs, and the unavailability of skilled workers or our failure to attract and retain qualified personnel could adversely affect us* of this Form 10-K.

Seasonality. Seasonal weather can affect demand for LNG and accordingly can impact our ability to sell LNG during the commissioning of our facilities or once our facilities achieve their respective CODs. We have already begun experiencing, and we expect to experience for our other projects, the effects of market volatility and fluctuation in seasonal demand for LNG in our existing markets. For example, temperature and weather in the markets we supply, as well as the amount of natural gas in storage in such markets, may affect both power demand

and power generation mix, including the portion of electricity provided through other sources of energy, such as hydroelectric, solar or wind, thus affecting the need for LNG. Further, slower-than-expected inventory withdrawal due to mild weather can decrease the demand for LNG. Other factors, including but not limited to the price spread between European and Asian LNG indices and the availability of LNG tankers and the routes they choose to take due to seasonal and other factors can also affect the price of LNG. As a result, our ability to generate cash proceeds from LNG sales on a spot basis, and to enter into new SPAs for the sale of LNG, may be impacted by such factors, which may in turn result in fluctuations in revenue during quarters of high and low demand, respectively, and could have a disproportionate effect on our results of operations. As such, our results of operations across different fiscal quarters may not be comparable or accurate indicators of our future performance. For more information on these risks, see Item 1A.—*Risk Factors*—*Risks Relating to Our Business*—*Seasonal fluctuations will cause our business and results of operations to vary among quarters, which could adversely affect our business and results of operations* of this Form 10-K.

Macroeconomic Trends. Macroeconomic conditions, such as high inflation and elevated interest rates, continue to be sources of volatility and uncertainty for global economic activity, and may affect our project costs and operations, as discussed above. See Item 1A.—*Risk Factors*—*Risks Relating to Our Business*—*Our ability to maintain profitability and positive operating cash flows is subject to significant uncertainty* of this Form 10-K. Ongoing geopolitical conflicts in Ukraine, the Middle East, and tensions in United States-China relations may drive further economic instability and inflationary pressures, as well as increase risks for the global flow of goods, including energy. In the case of the LNG market, these geopolitical conflicts have and may continue to impact the availability of materials required for the development of LNG projects, in addition to disrupting the supply of LNG, resulting in price volatility on non-SPA volumes. For additional information on historical net spread volatility see Item 1A.—*Risk Factors*—*Risks Relating to Our Business*—*Our ability to generate proceeds from sales of commissioning cargos is subject to significant uncertainty and volatility in such proceeds, given significant volatility in spot-market prices* of this Form 10-K. Historical proceeds from such sales at the Calcasieu Project, which has had an extended commissioning period due to unanticipated challenges with equipment reliability that we are in the process of remediating, may not be indicative of the duration of the commissioning period or the amount of proceeds for any future period or for any of our other projects including bolt-on expansions thereof.

Results of Operations

Year Ended December 31, 2024 compared to Year Ended December 31, 2023

The following table shows a summary of our results of operations for the periods indicated:

	Years ended December 31,		Change	
	2024	2023	($)	(%)
REVENUE	$ 4,972	$ 7,897	$ (2,925)	(37)%
OPERATING EXPENSE				
Cost of sales (exclusive of depreciation and amortization shown separately below)	1,351	1,684	(333)	(20)%
Operating and maintenance expense	589	391	198	51 %
General and administrative expense	312	224	88	39 %
Development expense	635	490	145	30 %
Depreciation and amortization	322	277	45	16 %
Insurance recoveries, net	—	(19)	19	(100)%
Total operating expense	3,209	3,047	162	5 %
INCOME FROM OPERATIONS	1,763	4,850	(3,087)	(64)%
OTHER INCOME (EXPENSE)				
Interest income	244	172	72	42 %
Interest expense, net	(584)	(641)	57	(9)%
Gain on interest rate swaps	774	174	600	NM
Loss on financing transactions	(14)	(123)	109	(89)%
Total other income (expense)	420	(418)	838	(200)%
INCOME BEFORE INCOME TAX EXPENSE	2,183	4,432	(2,249)	(51)%
Income tax expense	437	816	(379)	(46)%
NET INCOME	$ 1,746	$ 3,616	$ (1,870)	(52)%
Less: Net income attributable to redeemable stock of subsidiary	144	130	14	11 %
Less: Net income attributable to non-controlling interests	59	805	(746)	(93)%
Less: Dividends on VGLNG Series A Preferred Shares	68	—	68	NM
NET INCOME ATTRIBUTABLE TO COMMON STOCKHOLDERS	$ 1,475	$ 2,681	$ (1,206)	(45)%

NM Percentage not meaningful.

Revenue

Revenue was $5.0 billion for the year ended December 31, 2024, a $2.9 billion, or 37%, decrease from $7.9 billion during the year ended December 31, 2023. This decrease was primarily due to lower LNG sales prices for the sale of commissioning cargos of $2.8 billion and lower LNG sales volumes of $139 million.

Operating Expense

Cost of Sales

Cost of sales was $1.4 billion for the year ended December 31, 2024, a $333 million, or 20%, decrease from $1.7 billion during the year ended December 31, 2023. This decrease was primarily due to the combined impact of a decrease in the net cost of natural gas and improved plant efficiency of $311 million and a decrease in LNG sales volumes of $22 million.

Operating and Maintenance Expense

Operating and maintenance expense was $589 million for the year ended December 31, 2024, a $198 million, or 51%, increase from $391 million during the year ended December 31, 2023. This increase was primarily due to $67 million higher operating costs at the Calcasieu Project to support ongoing commissioning and remediation work and higher legal costs of $49 million, a $48 million increase in operating costs for our LNG tankers with no corresponding costs in 2023, and $14 million in higher operating costs for the Plaquemines Project mainly resulting from an increase in asset retirement obligation, or ARO, accretion.

General and Administrative Expense

General and administrative expense was $312 million for the year ended December 31, 2024, a $88 million, or 39%, increase from $224 million during the year ended December 31, 2023. This increase was primarily due to higher personnel costs of $43 million due to an increase in employee headcount, increases in promotional activities of $10 million, and increases in external services of $6 million.

Development Expense

Development expense was $635 million for the year ended December 31, 2024, a $145 million, or 30%, increase from $490 million during the year ended December 31, 2023. This increase was primarily due to higher development costs of $91 million for engineering and environmental services related to the CP2 Project and $32 million related to pipeline projects and higher lease costs of $33 million, partially offset by a decrease of $36 million in legal costs related to construction contractor disputes at the Calcasieu Project.

Depreciation and Amortization

Depreciation and amortization was $322 million for the year ended December 31, 2024, a $45 million, or 16%, increase from $277 million during the year ended December 31, 2023. This increase was primarily attributable to placing $11.4 billion of property, plant and equipment at the Plaquemines Project in service from an accounting perspective in December 2024 and the acquisition of two LNG tankers.

Insurance Recoveries, Net

Insurance recoveries, net were $19 million for the year ended December 31, 2023, due to the recognition of our portion of insurance claims received in connection with Hurricane Laura. There was no similar activity during the year ended December 31, 2024.

Income from Operations

Income from operations was $1.8 billion for the year ended December 31, 2024, a $3.1 billion, or 64%, decrease from $4.9 billion during the year ended December 31, 2023. This decrease was primarily the result of lower revenue, partially offset by lower cost of sales, from the sale of LNG, as discussed above. In addition, there were increases in operating and maintenance expense, development expense, general and administrative expense, and depreciation and amortization, as discussed above.

Other Income or Expense

Interest Income

Interest income was $244 million during the year ended December 31, 2024, a $72 million, or 42%, increase from $172 million during the year ended December 31, 2023. This increase was primarily due to higher average cash balances and interest rates during the year ended December 31, 2024, compared to the same period in 2023.

Interest Expense, Net

Interest expense, net was $584 million during the year ended December 31, 2024, a $57 million, or 9%, decrease from $641 million during the year ended December 31, 2023. This decrease was primarily due to lower commitment fees of $34 million, primarily at the Plaquemines Project, and higher capitalizable interest costs of $15 million.

Gain on Interest Rate Swaps

Gain on interest rate swaps was $774 million for the year ended December 31, 2024, a $600 million increase from $174 million during the year ended December 31, 2023. This increase was primarily due to an increase in the gain on the Plaquemines Project interest rate swaps of $572 million, driven by favorable changes in the forward interest rate curves over higher notional amounts, and a favorable change on the Calcasieu Project interest rate swaps of $30 million, driven by favorable changes in the forward interest rate curves over lower notional amounts.

Loss on Financing Transactions

Loss on financing transactions was $14 million for the year ended December 31, 2024, a $109 million, or 89%, decrease from $123 million during the year ended December 31, 2023. This decrease was primarily due to the write-off of debt issuance costs associated with the full prepayment of the Plaquemines Equity Bridge Facility during the year ended December 31, 2024, as compared to the write-off of debt issuance costs associated with the prepayment of a term loan at VGLNG, and the partial prepayments of both the Plaquemines Equity Bridge Facility and the Calcasieu Pass Credit Facilities during the year ended December 31, 2023.

Income before Income Tax Expense

Income before income tax expense was $2.2 billion for the year ended December 31, 2024, a $2.2 billion, or 51%, decrease from $4.4 billion during the year ended December 31, 2023. This decrease was primarily the result of the decrease in our income from operations partially offset by an increase in our gain on interest rate swaps, as discussed above.

Income Tax Expense

Income tax expense was $437 million for the year ended December 31, 2024, a $379 million, or 46%, decrease from $816 million during the year ended December 31, 2023, primarily driven by a decrease in pre-tax income. Our effective tax rate was 20.0% for the year ended December 31, 2024, as compared to 18.4% for the year ended December 31, 2023. The 2024 effective tax rate was lower than the statutory income tax rate due to a combination of factors including, research and development tax credits, guaranteed payments to non-controlling interests, and non-deductible expenses.

Net Income

Net income was $1.7 billion for the year ended December 31, 2024, a $1.9 billion, or 52%, decrease from $3.6 billion during the year ended December 31, 2023. This decrease was primarily the result of a decrease in income from operations due to lower revenue earned from the sale of LNG, partially offset by lower cost of sales, partially offset by an increase in gain on derivatives and a decrease in income tax expense, as discussed above.

Net Income Attributable to Redeemable Stock of Subsidiary

Net income attributable to redeemable stock of subsidiary was $144 million for the year ended December 31, 2024, a $14 million, or 11%, increase from $130 million during the year ended December 31, 2023. This increase was from 2024 paid-in-kind distributions on the Redeemable Preferred Units.

Net Income Attributable to Non-controlling Interests

Net income attributable to non-controlling interests was $59 million for the year ended December 31, 2024, a $746 million, or 93%, decrease from $805 million during the year ended December 31, 2023. This decrease was primarily due to the 2023 repurchase of VGLNG common stock by VGLNG and the 2023 Reorganization Transactions resulting in no non-controlling interest at the VGLNG level after September 30, 2023.

Dividends on VGLNG Series A Preferred Shares

Dividends on VGLNG Series A Preferred Shares were $68 million for the year ended December 31, 2024. This increase was due to the September 2024 issuance of the VGLNG Series A Preferred Shares and the corresponding accumulated but undeclared dividends. There was no similar activity during the year ended December 31, 2023.

Net Income Attributable to Common Stockholders

Net income attributable to common stockholders was $1.5 billion for the year ended December 31, 2024, a $1.2 billion, or 45%, decrease from $2.7 billion during the year ended December 31, 2023. This decrease was primarily resulting from the changes discussed above.

Results of Operations

Year Ended December 31, 2023 compared to Year Ended December 31, 2022

The following table shows a summary of our results of operations for the periods indicated:

	Years ended December 31,		Change	
	2023	2022	($)	(%)
REVENUE	$ 7,897	$ 6,448	$ 1,449	22 %
OPERATING EXPENSE				
Cost of sales (exclusive of depreciation and amortization shown separately below)	1,684	2,093	(409)	(20)%
Operating and maintenance expense	391	140	251	179 %
General and administrative expense	224	191	33	17 %
Development expense	490	311	179	58 %
Depreciation and amortization	277	158	119	75 %
Insurance recoveries, net	(19)	—	(19)	NM
Total operating expense	3,047	2,893	154	5 %
INCOME FROM OPERATIONS	4,850	3,555	1,295	36 %
OTHER INCOME (EXPENSE)				
Interest income	172	18	154	NM
Interest expense, net	(641)	(592)	(49)	8 %
Gain on interest rate swaps	174	1,212	(1,038)	(86)%
Loss on embedded derivatives	—	(14)	14	NM
Loss on financing transactions	(123)	(635)	512	(81)%
Total other expense	(418)	(11)	(407)	NM
INCOME BEFORE INCOME TAX EXPENSE	4,432	3,544	888	25 %
Income tax expense	816	447	369	83 %
NET INCOME	$ 3,616	$ 3,097	$ 519	17 %
Less: Net income attributable to redeemable stock of subsidiary	130	118	12	10 %
Less: Net income attributable to non-controlling interests	805	1,121	(316)	(28)%
NET INCOME ATTRIBUTABLE TO COMMON STOCKHOLDERS	$ 2,681	$ 1,858	$ 823	44 %

NM Percentage not meaningful.

Revenue

Revenue was $7.9 billion for the year ended December 31, 2023, a $1.4 billion, or 22%, increase from $6.4 billion during the year ended December 31, 2022. This increase was primarily due to $7.1 billion from higher LNG sales volumes, partially offset by a decrease of $5.8 billion due to lower pricing. The Calcasieu Project facility assets were in service from an accounting perspective and generating revenue for the entire year ended December 31, 2023, as compared to being placed in service from an accounting perspective on a sequential basis between April and August 2022, and therefore generating revenue for only a portion of the year ended December 31, 2022. The proceeds attributable to test LNG sales generated prior to the Calcasieu Project facilities being in service from an accounting perspective, and therefore recognized as construction in progress and not as revenue, were $1.8 billion for the year ended December 31, 2022.

Operating Expense

Cost of Sales

Cost of sales was $1.7 billion for the year ended December 31, 2023, a $409 million, or 20%, decrease from $2.1 billion during the year ended December 31, 2022. This decrease was due to $2.8 billion from lower natural gas prices and higher efficiency, partially offset by an increase of $2.4 billion from higher LNG sales volumes. The Calcasieu Project facility assets were in service from an accounting perspective and incurring cost of sales for the entire year ended December 31, 2023, as compared to being placed in service from an accounting perspective on a sequential basis between April and August 2022, and therefore incurring cost of sales for only a portion of the year ended December 31, 2022. The cost attributable to the production of test LNG sales incurred prior to the Calcasieu Project facilities being in service from an accounting perspective, and therefore recognized as construction in progress and not as cost of sales, was $723 million for the year ended December 31, 2022.

Operating and Maintenance Expense

Operating and maintenance expense was $391 million for the year ended December 31, 2023, a $251 million, or 179%, increase from $140 million during the year ended December 31, 2022. This increase was primarily due to higher operating costs at the Calcasieu Project to support ongoing commissioning and remediation work, personnel costs, and insurance, and higher operating costs in support of the Plaquemines Project primarily due to an increase in non-capitalizable personnel costs and ARO accretion.

General and Administrative Expense

General and administrative expense was $224 million for the year ended December 31, 2023, a $33 million, or 17%, increase from $191 million during the year ended December 31, 2022. This increase was primarily due to increased personnel costs due to an increase in employee headcount.

Development Expense

Development expense was $490 million for the year ended December 31, 2023, a $179 million, or 58%, increase from $311 million during the year ended December 31, 2022. This increase was primarily due to an increase in early development activities and personnel costs related to the CP2 Project, partially offset by the Plaquemines Project being deemed probable in March 2022, and the majority of the costs to develop the facility subsequently being capitalized.

Depreciation and Amortization

Depreciation and amortization was $277 million for the year ended December 31, 2023, a $119 million, or 75%, increase from $158 million during the year ended December 31, 2022. This increase was primarily due to placing additional property, plant and equipment at the Calcasieu Project in service from an accounting perspective throughout the year ended December 31, 2022.

Insurance Recoveries, Net

Insurance recoveries, net were $19 million for the year ended December 31, 2023, a $19 million increase from the year ended December 31, 2022. This increase was mainly due to the recognition of our portion of insurance claims received in connection with Hurricane Laura storm costs during the year ended December 31, 2023, with no similar activity during the year ended December 31, 2022.

Income from Operations

Income from operations was $4.9 billion for the year ended December 31, 2023, a $1.3 billion, or 36%, increase from $3.6 billion during the year ended December 31, 2022. This increase was primarily a result of higher sales volumes and margin earned from the sale of LNG produced by the Calcasieu Project assets placed in service from an accounting perspective between April and August 2022.

Other Income or Expense

Interest Income

Interest income was $172 million for the year ended December 31, 2023, a $154 million increase from $18 million during the year ended December 31, 2022. This increase was primarily due to larger average cash balances and higher interest rates during the year ended December 31, 2023, compared to the year ended December 31, 2022.

Interest Expense, Net

Interest expense, net was $641 million for the year ended December 31, 2023, a $49 million, or 8%, increase from $592 million during the year ended December 31, 2022. This increase was primarily due to higher interest costs associated with increased debt outstanding and higher interest rates. These increases were partially offset by higher capitalized interest, primarily at the Plaquemines Project and corporate, as a result of more interest meeting the threshold for capitalization, partially offset by a reduction in capitalized interest at the Calcasieu Project due to the assets being placed in service from an accounting perspective in 2022.

Gain on Interest Rate Swaps

Gain on interest rate swaps was $174 million for the year ended December 31, 2023, a $1.0 billion, or 86%, decrease from $1.2 billion during the year ended December 31, 2022. This decrease was primarily due to a reduction in the gain on the Plaquemines Project interest rate swaps of $838 million, due to smaller changes in the forward interest rate curves over higher notional amounts, and a reduction in the gain on the Calcasieu Project interest rate swaps of $197 million, due to smaller changes in the forward interest rate curves over lower notional amounts during the year ended December 31, 2023 compared to the year ended December 31, 2022.

Loss on Embedded Derivatives

Loss on embedded derivatives was nil for the year ended December 31, 2023, a $14 million decrease from the loss of $14 million during the year ended December 31, 2022. This decrease was due to the full prepayment of a convertible note instrument in December 2022, with no corresponding change in the fair value of embedded derivatives during the same period in 2023.

Loss on Financing Transactions

Loss on financing transactions was $123 million for the year ended December 31, 2023, a $512 million, or 81%, decrease from $635 million during the year ended December 31, 2022. This decrease was primarily due to the write-off of debt issuance costs associated with the prepayment of a term loan at VGLNG and the partial prepayments of the Calcasieu Pass Credit Facilities and the Plaquemines Equity Bridge Facility during the year ended December 31, 2023, compared to the write-off of debt issuance costs associated with the prepayment of a convertible note instrument, the refinancing of a term loan at VGLNG, and the reduction and repayment of debt associated with the Plaquemines Project during the year ended December 31, 2022.

Income before Income Tax Expense

Income before income tax expense was $4.4 billion for the year ended December 31, 2023, a $888 million, or 25%, increase from $3.5 billion during the year ended December 31, 2022. The increase was primarily a result of the increase in our income from operations, as discussed above.

Income Tax Expense

Income tax expense was $816 million for the year ended December 31, 2023, a $369 million, or 83%, increase from $447 million during the year ended December 31, 2022. Our effective tax rate was 18.4% for the year ended December 31, 2023 compared to 12.5% for the year ended December 31, 2022. The 2023 effective tax rate was impacted by income tax benefits related to the foreign derived intangible income, or FDII, deduction and other permanent GAAP to tax differences. The 2022 effective tax rate was impacted by an income tax benefit from the release of a significant portion of our valuation allowance. This tax benefit was partially offset by tax expense related to the disallowed interest expense and disallowed losses from the prepayment of a convertible note instrument.

Net Income

Net income was $3.6 billion for the year ended December 31, 2023, a $519 million, or 17%, increase from $3.1 billion during the year ended December 31, 2022. This increase was primarily a result of an increase in income from operations due to higher revenue, partially offset by cost of sales, from the sale of LNG produced by the Calcasieu Project, partially offset by an increase in income tax expense and a decrease in gain on interest rate swaps, as discussed above.

Net Income Attributable to Redeemable Stock of Subsidiary

Net income attributable to redeemable stock of subsidiary was $130 million during the year ended December 31, 2023, a $12 million, or 10%, increase from $118 million during the year ended December 31, 2022. This increase was primarily from 2023 paid-in-kind distributions on the Redeemable Preferred Units.

Net Income Attributable to Non-controlling Interests

Net income attributable to non-controlling interests was $805 million during the year ended December 31, 2023, a $316 million, or 28%, decrease from $1.1 billion during the year ended December 31, 2022. This decrease was primarily due to the 2023 repurchase of VGLNG common stock by VGLNG and the 2023 Reorganization Transactions resulting in no non-controlling interest at the VGLNG level after September 30, 2023.

Net Income Attributable to Common Stockholders

Net income attributable to common stockholders was $2.7 billion for the year ended December 31, 2023, a $823 million, or 44%, increase from $1.9 billion during the year ended December 31, 2022. This increase was primarily due to the changes discussed above.

Segment Results of Operations

We have three reportable segments, which consist of the Calcasieu Project, the Plaquemines Project, and the CP2 Project. Each reportable segment includes activity of both the respective liquefaction and export terminal and the associated pipeline facilities that will supply the natural gas to that export terminal. Activities relating to certain development stage projects and our shipping business, overhead costs not directly associated with our LNG projects (for example, general and administrative and marketing expenses) and inter-segment eliminations are not material and therefore are included in corporate, other and eliminations. Our segment performance is evaluated based on income (loss) from operations.

Year Ended December 31, 2024 compared to Year Ended December 31, 2023

The following table shows a summary of our segment income (loss) from operations for the periods indicated:

	Years ended December 31,		Change	
	2024	2023	($)	(%)
Calcasieu Project	$ 2,813	$ 5,598	$ (2,785)	(50)%
Plaquemines Project	(217)	(187)	(30)	16 %
CP2 Project	(500)	(362)	(138)	38 %
Corporate, other and eliminations(1)	(333)	(199)	(134)	67 %
Total	$ 1,763	$ 4,850	$ (3,087)	(64)%

(1) Includes costs associated with the CP3 Project, the Delta Project, our shipping business, our pipeline development projects and certain corporate activities.

Calcasieu Project

During the year ended December 31, 2024, the Calcasieu Project had income from operations of $2.8 billion, a $2.8 billion, or 50%, decrease from $5.6 billion during the year ended December 31, 2023.

This decrease was primarily due to:

- a decrease in revenue of $3.0 billion due to a decrease in LNG sales prices of $2.8 billion and lower LNG sales volumes of $124 million; and
- an increase in operating and maintenance expense of $133 million primarily due to higher operating costs to support ongoing commissioning and remediation work and legal costs.

These decreases to income from operations were partially offset by:

- a net decrease in cost of sales of $321 million due to the combined impact of a decrease in the net cost of natural gas and improved plant efficiency of $304 million and a decrease in LNG sales volumes of $25 million; and
- a decrease in development expense of $38 million primarily due to lower legal costs related to construction contractor disputes.

The Calcasieu Project sold a portion of the LNG produced by the project to VG Commodities.

Plaquemines Project

During the year ended December 31, 2024, the Plaquemines Project had a loss from operations of $217 million, a $30 million, or 16%, increase from $187 million during the year ended December 31, 2023.

This increase was primarily due to:

- an increase in depreciation and amortization of $16 million from placing a portion, or $11.4 billion, of the facility's assets in service from an accounting perspective in December 2024;
- an increase in operating and maintenance expense of $14 million primarily due to an increase in ARO accretion; and
- an increase in cost of sales of $13 million, due to the sale of LNG produced by the portion of the Plaquemines Project assets placed in service from an accounting perspective in December 2024, compared to no cost of sales for the comparative period in 2023.

These increases to loss from operations were partially offset by:

- an increase in revenue of $23 million due to the sale of LNG produced by the portion of the Plaquemines Project assets placed in service from an accounting perspective in December 2024, compared to no revenue for the corresponding period in 2023.

The Plaquemines Project sold the LNG produced by the project to VG Commodities.

CP2 Project

During the year ended December 31, 2024, the CP2 Project had a loss from operations of $500 million, a $138 million, or 38%, increase from $362 million during the year ended December 31, 2023. This increase was primarily driven by an increase in development expense of $123 million primarily due to $91 million of higher costs for engineering and environmental services and $18 million for lease costs as the Company continued to advance the project.

Corporate, other and eliminations

During the year ended December 31, 2024, corporate, other and eliminations had a loss from operations of $333 million, a $134 million, or 67%, increase from $199 million during the year ended December 31, 2023.

This increase was primarily due to:

- an increase in general and administrative expenses of $67 million primarily due to higher personnel costs associated with an increase in employee headcount, increased promotional activities, and increased external services;
- an increase in development expense of $57 million primarily related to pipeline development projects;
- an increase in operating and maintenance expense of $52 million related to the operation of our newly acquired LNG tankers; and
- an increase in depreciation and amortization of $16 million primarily due to acquisition of two LNG tankers acquired and placed in service during the year ended December 31, 2024, compared to no similar activity during the same period in 2023.

These increases to loss from operations were partially offset by an increase of $329 million in revenue, offset by a corresponding increase of $266 million in cost of sales, from the sale of LNG by VG Commodities. This increase was partially offset by an increase of $8 million of eliminated income from operations due to intercompany sales of LNG.

Year Ended December 31, 2023 compared to Year Ended December 31, 2022

The following table shows a summary of our segment income (loss) from operations for the periods indicated:

	Years ended December 31,		Change	
	2023	2022	($)	(%)
Calcasieu Project	$ 5,598	$ 4,042	$ 1,556	38 %
Plaquemines Project	(187)	(269)	82	(30)%
CP2 Project	(362)	(34)	(328)	NM
Corporate, other and eliminations(1)	(199)	(184)	(15)	8 %
Total	$ 4,850	$ 3,555	$ 1,295	36 %

(1) Includes costs associated with the CP3 Project, the Delta Project, our shipping business, our pipeline development projects and certain corporate activities.

NM Percentage not meaningful.

Calcasieu Project

For the year ended December 31, 2023, the Calcasieu Project had income from operations of $5.6 billion, a $1.6 billion, or 38%, increase from $4.0 billion during the year ended December 31, 2022. This increase was primarily due to:

- an increase in revenue of $1.4 billion primarily due to $7.1 billion from higher LNG sales volumes, partially offset by a decrease of $5.8 billion due to lower pricing. The Calcasieu Project facility assets were in service from an accounting perspective and generating revenue for the entire year ended December 31, 2023, as compared to being placed in service from an accounting perspective on a sequential basis between April and August 2022, and therefore generating revenue for only a portion of the year ended December 31, 2022. The proceeds attributable to test LNG sales generated prior to the facilities being in service from an accounting perspective, and therefore recognized as construction in progress and not revenue, were $1.8 billion for the year ended December 31, 2022; and
- a decrease in cost of sales of $409 million due to $2.8 billion from lower natural gas prices and higher efficiency, partially offset by an increase of $2.4 billion from higher LNG sales volumes. The Calcasieu Project facility assets were in service from an accounting perspective and incurring cost of sales for the entire year ended December 31, 2023, as compared to being placed in service from an accounting perspective on a sequential basis between April and August 2022, and therefore incurring cost of sales for only a portion of the year ended December 31, 2022. The cost attributable to the production of test LNG sales incurred prior to the facilities being in service from an accounting perspective, and therefore recognized as construction in progress and not cost of sales, was $723 million for the year ended December 31, 2022.

These net favorable changes were partially offset by:

- an increase in operating and maintenance expense of $188 million, primarily due to higher operating costs in support of LNG production including costs to support ongoing commissioning and remediation work, personnel costs and insurance costs; and
- an increase in depreciation and amortization expense of $112 million, primarily due to placing additional property, plant and equipment at the Calcasieu Project in service from an accounting perspective throughout the year ended December 31, 2022.

Plaquemines Project

For the year ended December 31, 2023, the Plaquemines Project had a loss from operations of $187 million, a $82 million, or 30%, decrease from $269 million during the year ended December 31, 2022. This decrease was primarily due to a decrease in development expense of $184 million due to the Plaquemines Project being deemed probable in March 2022, and the costs to develop and construct the facility largely being capitalized in 2023. This decrease was partially offset by an increase in operating and maintenance expense of $64 million due to higher operating costs primarily due to an increase in non-capitalizable personnel costs and ARO accretion and an increase in general and administrative expenses of $37 million due to higher costs for administrative services.

CP2 Project

For the year ended December 31, 2023, the CP2 Project had a loss from operations of $362 million, a $328 million increase from $34 million during the year ended December 31, 2022. This increase was primarily driven by an increase in development expense of $328 million primarily due to early development, pre-construction and personnel costs related to the CP2 Project that were not capitalizable.

Corporate, other and eliminations

For the year ended December 31, 2023, corporate, other and eliminations had a loss from operations of $199 million, a $15 million, or 8%, increase from $184 million during the year ended December 31, 2022. This increase was primarily driven by an increase in development expense of $14 million, primarily related to a pipeline development project, partially offset by a lower fee to secure future manufacturing capacity during the year ended December 31, 2023.

Liquidity and Capital Resources

General

We have a limited operational history and we did not generate any LNG sales proceeds prior to 2022. We may incur losses as we continue to construct and develop our projects and explore the development of other potential natural gas liquefaction and export projects.

Funding Requirements

The operation, commissioning, construction and development of our projects requires significant capital expenditures.

We expect that the remaining project costs to achieve COD for the Calcasieu Project will be funded with cash held in cash reserve accounts pursuant to our project financing arrangements and reflected as restricted cash in our financial statements at the Calcasieu Project in an amount expected to be necessary to complete the project and achieve COD under the Calcasieu Foundation SPAs.

We currently estimate that the total project costs for the Plaquemines Project will be approximately $23.3 billion to $23.8 billion, including EPC contractor profit and contingency, owners' costs and financing costs. Of the total project costs for the Plaquemines Project, approximately $19.8 billion had been paid for as of December 31, 2024 and had obtained approximately $15.0 billion of project-level debt financing comprised of an approximately $12.9 billion term loan facility and $2.1 billion working capital revolving facility, and made an aggregate of approximately $8.1 billion of equity contributions. As of December 31, 2024, approximately $12.7 billion of such project-level debt financing was outstanding, and we had additional available borrowing capacity of approximately $940 million thereunder. We believe we have sufficient cash and access to substantial commissioning cargo proceeds to fund the completion of the Plaquemines Project based on our current estimate of the total project costs. However, we may make additional equity contributions to the extent that total project costs exceed the low-end of the range of estimated total project costs above and that such costs exceed the available project-level debt and equity financing and net proceeds from the sale of commissioning cargos.

We currently estimate that the total project costs for the CP2 Project will be approximately $27.0 billion to $28.0 billion, including EPC contractor profit and contingency, owners' costs and financing costs. Of the total project costs for the CP2 Project, approximately $4.0 billion had been paid for as of December 31, 2024. Given that we have not executed certain contracts to construct the CP2 Project, including the EPC contract with respect to Phase 2 of the CP2 Project, this estimate is based upon the contracts that we have in place for the CP2 Project and our construction cost experiences with the Calcasieu Project and the Plaquemines Project. The cost estimate for the CP2 Project reflects the current inflationary environment, and may be higher, potentially materially, compared to our current estimates as a result of many factors. In addition, we expect to construct longer pipelines for the CP2 Project than for the Calcasieu Project and the Plaquemines Project. Furthermore, our cost estimates might change due to factors such as unexpected delays in the construction or commissioning of our projects, the execution of any repair or warranty work and change orders or amendments to certain material construction contracts, including final terms of or amendments to any EPC contract for such projects, and/or other construction or supply contracts. For more details on these risks, see Item 1A.—*Risk Factors*—*Risks Relating to Our Projects and Other Assets—Our estimated costs for our projects have been, and continue to be, subject to change due to various factors* of this Form 10-K.

These estimates do not reflect the potential impact of any new tariffs that have been announced or implemented since December 31, 2024 or that may be implemented in the future. Our project budget estimates included in this Form 10-K reflect all tariffs in place, and Section 232 exemptions secured, as of December 31, 2024. Certain of our products, including our Baker Hughes sourced liquefaction train system modules and power island components, are foreign sourced and specified under our regulatory approvals, offering no domestically sourced alternative and potentially exposing us to the effects of any future tariffs that may be imposed. There can be no assurance as to the extent of any future tariffs, or the impact thereof on any of our estimates of total project costs for our projects, which could have a material adverse effect on our construction budgets and limit our growth prospects.

We intend to finance the construction and development of the CP2 Project, the CP3 Project, the Delta Project, and any bolt-on expansions or future LNG projects as well as the related owners' costs through one or more sources of debt and equity financing. The amount of project-level equity funding that is required for any of our projects relative to the amount of project-level debt financing may differ between our projects. Generally, we expect to finance approximately 50% to 75% of the anticipated construction costs of each of our projects with project-level debt financing (which may include limited recourse debt), and the remaining 25% to 50% with project-level equity (which may consist of equity contributions by us, equity financing transactions, mezzanine financing and/or other similar financing alternatives). The final terms and availability of such debt and equity financing will depend on various factors, including market conditions at the time. We may consider alternative structures to raise capital for those projects and, as a result, there can be no assurance that the financing structure for the CP2 Project, the Delta Project, the CP3 Project or any future project we may develop will be similar to those used for the Calcasieu Project and the Plaquemines Project.

Contractual Obligations

We have contractual obligations involving commitments to third parties that impact our liquidity and capital resource needs. In addition to the construction and development obligations discussed above, the following table summarizes our contractual obligations as of December 31, 2024 (in millions):

	Years ended December 31,			
	2025	2026-2029	Thereafter	Total
Operating contracts				
Natural gas supply and transportation[1]	$ 2,904	$ 9,628	$ 6,701	$ 19,233
Leases	144	342	1,367	1,853
Regasification capacity	6	115	707	828
Other	190	91	43	324
Other capital projects				
LNG tankers	883	288	—	1,171
Pipeline development projects	882	55	—	937
Total	$ 5,009	$ 10,519	$ 8,818	$ 24,346

(1) Includes contractual obligations under (i) natural gas forward purchase contracts for the supply of feed gas to the Calcasieu Project and the Plaquemines Project for which we intend to take physical delivery through October 2031, and (ii) long-term natural gas firm transportation service agreements with various interstate pipeline companies to secure natural gas transportation requirements for the Calcasieu Project and the Plaquemines Project through April 2045 and August 2046, respectively.

In addition, we have significant debt and associated interest expense obligations at our subsidiaries, consisting of debt incurred by VGLNG as well as debt incurred by subsidiaries of VGLNG in connection with financing the Calcasieu Project and the Plaquemines Project. We anticipate obtaining significant additional financing and incurring related financing fees and interest expense in connection with the CP2 Project, the CP3 Project, the Delta Project, our pipeline development projects, our LNG tankers, and any bolt-on expansions or future LNG projects.

Outstanding debt and associated interest expense obligations of subsidiaries of VGLNG have no recourse to nor are guaranteed by the Company or VGLNG. The following table summarizes our debt and associated interest expense obligations of subsidiaries of VGLNG as of December 31, 2024 (in millions):

	Years ended December 31,			
	2025	2026-2029	Thereafter	Total
Principal maturities[(1)(2)]	$ 190	$ 14,777	$ 3,500	$ 18,467
Interest payments[(3)]	942	2,404	328	3,674
Total	$ 1,132	$ 17,181	$ 3,828	$ 22,141

(1) Reflects aggregate contractual maturities for outstanding principal as of December 31, 2024. See —*Funding Requirements* and Item 8.—*Financial Statements and Supplementary Data*—*Note 11 – Debt* of this Form 10-K, for more information.

(2) Excludes $1.5 billion of redeemable preferred shares of Calcasieu Pass Funding, presented as redeemable stock of subsidiary which is redeemable at the option of the holder thereof upon the occurrence of certain events. See Item 8.—*Financial Statements and Supplementary Data*—*Note 17 – Redeemable Stock of Subsidiary* of this Form 10-K.

(3) Inclusive of the expected settlements of interest rate swaps that economically hedge the variable rate interest incurred by the Calcasieu Project and the Plaquemines Project. See Item 8.—*Financial Statements and Supplementary Data*—*Note 11 – Debt* of this Form 10-K, for more information.

Outstanding debt and associated interest expense obligations of VGLNG are secured by its equity interests in the direct wholly-owned subsidiaries of VGLNG that directly or indirectly own our LNG projects. The following table summarizes our debt and associated interest expense obligations of VGLNG (including $84 million of indebtedness outstanding as of December 31, 2024, that was incurred by one of our subsidiaries and is guaranteed by VGLNG in certain circumstances) as of December 31, 2024 (in millions):

	Years ended December 31,			
	2025	2026-2029	Thereafter	Total
Principal maturities[(1)(2)]	$ —	$ 5,334	$ 5,750	$ 11,084
Interest payments[(3)]	965	3,450	829	5,244
Total	$ 965	$ 8,784	$ 6,579	$ 16,328

(1) Reflects aggregate contractual maturities for outstanding principal as of December 31, 2024. See —*Funding Requirements* and Item 8.—*Financial Statements and Supplementary Data*—*Note 11 – Debt* of this Form 10-K, for more information.

(2) Excludes $3.0 billion VGLNG Series A preferred shares presented as non-controlling interest and $270 million of corresponding annual preferred dividends that are subject to adjustment and accrue indefinitely, unless optionally redeemed in accordance with their terms. See Item 8.—*Financial Statements and Supplementary Data*—*Note 11 – Debt* of this Form 10-K, for more information.

(3) The interest rate for all VGLNG Senior Secured Notes is fixed. See Item 8.—*Financial Statements and Supplementary Data*—*Note 11 – Debt* of this Form 10-K for more information.

There are no material differences between the financial information presented on this Form 10-K and VGLNG's financial information other than (i) certain presentational differences related to the accounting for the VGLNG Series A Preferred Shares, and (ii) stockholders' equity of Venture Global, including the Class A common stock and any dividends payable thereon. See Item 15.—*Exhibits and Financial Statement Schedules*—*Schedule I Financial Information of Registrant* of this Form 10-K.

For further discussion of our contractual obligations as of December 31, 2024, see Item 8.—*Financial Statements and Supplementary Data*—*Note 15 – Commitments and Contingencies* of this Form 10-K for further information.

Sources and Uses of Cash

Since our inception, we have funded our operations and capital expenditures with various forms of financing, including private placements of equity securities, project equity financings and borrowings at VGLNG and our project entities, as well as cash from our operations.

We expect to meet our short-term cash requirements using operating cash flows and available liquidity, consisting of cash and cash equivalents, restricted cash and available borrowing capacity under our existing credit facilities. Additionally, we expect to meet our long-term cash requirements by using operating cash flows and other future potential sources of liquidity, which may include debt and equity offerings by us or our subsidiaries.

The following table provides a summary of our cash and available borrowing capacity under existing credit facilities as of December 31, 2024 (in millions):

	December 31, 2024
Cash and cash equivalents	$ 3,608
Restricted cash	1,006
Available borrowing capacity under our credit facilities[(1)]:	
Calcasieu Pass Working Capital Facility	231
Plaquemines Construction Term Loan	313
Plaquemines Working Capital Facility	627
Total available borrowing capacity under our credit facilities	1,171
Total cash and available borrowing capacity	$ 5,785

(1) Available borrowing capacity represents total borrowing capacity less outstanding borrowings and letters of credit under each of our credit facilities as of December 31, 2024.

In January 2025, we closed our IPO in which we issued and sold 70 million shares of Class A common stock. Our shares of Class A common stock were sold at an initial public offering price of $25.00 per share, which generated net proceeds of approximately $1.7 billion after deducting underwriting discounts and commissions of $70 million and approximately $10 million of offering expenses. See additional discussion in Item 8 —*Financial Statements and Supplementary Data*—*Note 25 – Subsequent Events* of this Form 10-K for further information.

As of December 31, 2024, our subsidiaries had approximately $29.6 billion in outstanding debt, which consisted of $11.1 billion of debt incurred or guaranteed by VGLNG and approximately $18.5 billion in project-level debt financing. In addition, our project-level equity investment subsidiaries for the Calcasieu Project, Calcasieu Holdings and Calcasieu Funding, have issued preferred units for total gross proceeds of $1.3 billion, with an aggregate liquidation preference of approximately $2.2 billion outstanding as of December 31, 2024, some of which require us to make preferential cash distributions to the holders under certain circumstances.

Following COD of the Calcasieu Project, but prior to August 19, 2027, no distributions will be permitted from the Calcasieu Project to VGLNG until any accrued distributions on the Redeemable Preferred Units have been settled in cash. Further, on and after August 19, 2027, no distributions will be permitted from the Calcasieu Project to VGLNG until the Redeemable Preferred Units have been fully redeemed in cash. As of December 31, 2024, the Redeemable Preferred Units had a redemption value of $1.5 billion of which $629 million was related to accrued distributions.

We commence production at our LNG projects on a sequential basis, with each liquefaction train being brought online as it is commissioned. On March 1, 2022, we successfully loaded our first cargo of LNG at the Calcasieu Project and all 18 liquefaction trains at the Calcasieu Project were capable of producing initial quantities of LNG by June 2022. In December 2024, we successfully loaded our first cargo of LNG at the Plaquemines project, to be sold on an as delivered basis, and eight liquefaction trains were capable of producing initial quantities of LNG by the end of December 2024.

The primary use of our capital resources to date has been to fund expenses related to the development, construction, commissioning and operation of our projects and our other key, complementary assets.

We believe that our current cash and cash equivalents, borrowing capacity under our existing credit facilities, the expected proceeds from sales of LNG at our projects as well as the proceeds from our IPO will provide us with sufficient liquidity for at least the next 12 months, and will enable us to fund our continuing operations, our upcoming LNG tanker milestone payments, our pipeline development projects and our expected pre-FID capital expenditures with respect to the CP2 Project, the CP3 Project, the Delta Project, and the potential bolt-on expansion for the Plaquemines Project.

We anticipate that we will need substantial additional debt and equity capital to commence full construction activities and achieve COD for the CP2 Project, the CP3 Project, the Delta Project, and the potential bolt-on expansion for the Plaquemines Project. We regularly evaluate market conditions, our capital needs, our liquidity profile, and various debt, equity and equity-linked financing alternatives at Venture Global, VGLNG, our project entities, and other subsidiaries, for opportunities to raise additional debt or equity capital and to support our growth and enhance our capital structure. The availability, timing and terms of any such additional debt and equity financing will depend on various factors, including market conditions at the time. To the extent we issue equity or equity-linked securities, there can be no assurance that any such funding will not be expensive or dilutive to stockholders.

If we are unable to obtain additional funding on a timely basis or on terms that are acceptable to us, we will have to delay, scale back or eliminate construction plans for the CP2 Project, the CP3 Project, the Delta Project, and the potential bolt-on expansion for the Plaquemines Project, any of which could harm our business, financial condition and results of operations. Any delays in construction could prevent us from commencing operations when we anticipate and would prevent us from realizing anticipated cash flows. Our future liquidity may also be affected by the timing of construction financing availability in relation to our incurrence of construction costs and other outflows as well as the timing of our receipt of cash flows under export contracts in relation to our incurrence of project and operating expenses. Moreover, many factors (including factors beyond our control) could result in a disparity between our liquidity sources and cash needs, including factors such as construction delays and breaches of construction agreements by our contractors. After the construction period, our business may not generate sufficient cash flow from operations, currently anticipated costs may increase or future borrowings may not be available to us in amounts sufficient to enable us to pay our indebtedness or to fund our other liquidity needs, including operating expenses. See Item 1A.—*Risk Factors* of this Form 10-K.

Material Financings

VGLNG Senior Secured Notes

In May 2023, VGLNG issued $2.25 billion aggregate principal amount of 8.125% Senior Secured Notes due 2028, or the VGLNG 2028 Notes, and $2.25 billion aggregate principal amount of 8.375% Senior Secured Notes due 2031, or the VGLNG 2031 Notes. The VGLNG 2028 Notes bear interest at a rate of 8.125% per annum and mature on June 1, 2028. The VGLNG 2031 Notes bear interest at a rate of 8.375% per annum and mature on June 1, 2031. The interest on each such series of notes is payable semi-annually in arrears on each June 1 and December 1.

In October 2023, VGLNG issued $2.5 billion aggregate principal amount of 9.500% Senior Secured Notes due 2029, or the VGLNG 2029 Notes, and $1.5 billion aggregate principal amount of 9.875% Senior Secured Notes due 2032, or the VGLNG 2032 Notes. In addition, in November 2023, VGLNG issued an additional $500 million aggregate principal amount of VGLNG 2029 Notes, and an additional $500 million aggregate principal amount of VGLNG 2032 Notes. The VGLNG 2029 Notes bear interest at a rate of 9.500% per annum and mature on February 1, 2029. The VGLNG 2032 Notes bear interest at 9.875% per annum and mature on February 1, 2032. The interest on each such series of notes is payable semi-annually in arrears on each February 1 and August 1, commencing on August 1, 2024.

In July 2024, VGLNG issued $1.5 billion aggregate principal amount of 7.000% Senior Secured Notes due 2030, or the VGLNG 2030 Notes. The VGLNG 2030 Notes bear interest at a rate of 7.000% per annum and mature on January 15, 2030. The interest on each such series of notes is payable semi-annually in arrears on each January 15 and July 15, commencing on January 15, 2025.

The VGLNG 2028 Notes, the VGLNG 2029 Notes, the VGLNG 2031 Notes, the VGLNG 2032 Notes and the VGLNG 2030 Notes are secured by first-priority liens in, subject to permitted liens and certain other exceptions, substantially all of our existing and future assets, if any, including our direct wholly-owned subsidiaries that directly or indirectly own the Calcasieu Project, the Plaquemines Project, the CP2 Project, the CP3 Project, the Delta Project, or any related pipeline.

VGLNG Series A Preferred Shares

In September 2024, VGLNG issued three million shares of 9.000% Series A Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock, with a $1,000 liquidation preference per share, or the VGLNG Series A Preferred Shares, for aggregate gross proceeds of $3.0 billion. The VGLNG Series A Preferred Shares are not convertible into any other securities and have limited voting rights. Cumulative cash dividends on the VGLNG Series A Preferred Shares are payable semi-annually, in arrears, on each March 30 and September 30, when, as and if declared by the board of directors of VGLNG. See Item 8.—*Financial Statements and Supplementary Data*—*Note 11 – Debt* and Item 8.—*Financial Statements and Supplementary Data*—*Note 18 – Non-Controlling Interests* of this Form 10-K for further discussion.

Project Debt and Equity Financing

Calcasieu Project. In August 2019, our subsidiary, VGCP, obtained $5.8 billion in project financing consisting of an approximately $5.5 billion senior secured construction term loan, or the Calcasieu Pass Construction Term Loan, and a $300 million senior secured working capital facility, or the Calcasieu Pass Working Capital Facility, or collectively, the Calcasieu Pass Credit Facilities, that mature on August 19, 2026 and bear interest at SOFR plus an applicable margin, payable monthly in arrears. The proceeds from the Calcasieu Pass Credit Facilities were used to fund the costs of developing, constructing and commissioning the Calcasieu Project. In September 2021, VGCP upsized the Calcasieu Pass Working Capital Facility by an incremental $255 million to $555 million. See Item 8.—*Financial Statements and Supplementary Data*—*Note 11 – Debt* and Item 8.—*Financial Statements and Supplementary Data*—*Note 18 – Non-Controlling Interests* of this Form 10-K for further discussion.

In May 2019, our subsidiaries, Calcasieu Funding and Calcasieu Holdings, entered into two unit purchase agreements with certain funds associated with Stonepeak Infrastructure Partners, pursuant to which Calcasieu Funding and Calcasieu Holdings issued 9 million and 4 million preferred units, respectively, for $1.3 billion of total gross proceeds at a face value of $100 per preferred unit. These transactions closed in August 2019 and proceeds were used to fund the equity portion of the cost of developing, constructing and commissioning the Calcasieu Project. See Item 8.—*Financial Statements and Supplementary Data*—*Note 17 – Redeemable Stock of Subsidiary* and Item 8.—*Financial Statements and Supplementary Data*—*Note 18 – Non-Controlling Interests* of this Form 10-K for further discussion.

In August 2021, VGCP issued $2.5 billion aggregate principal amount of senior secured notes, consisting of $1.25 billion of senior secured notes due 2029, or the VGCP 2029 Notes, and $1.25 billion of senior secured notes due 2031, or the VGCP 2031 Notes. The VGCP 2029 Notes bear interest at a rate of 3.875% per annum and the VGCP 2031 Notes bear interest at a rate of 4.125% per annum, with each series of notes payable semi-annually in arrears on February 15 and August 15 of each year. The VGCP 2029 Notes will mature on August 15, 2029 and the VGCP 2031 Notes will mature on August 15, 2031. In November 2021, VGCP issued $1.25 billion aggregate principal amount of senior secured notes due 2033, or the VGCP 2033 Notes. The VGCP 2033 Notes bear interest at a rate of 3.875% per annum, payable semi-annually in arrears on May 1 and November 1 of each year. The VGCP 2033 Notes will mature on November 1, 2033. In January 2023, VGCP issued $1.0 billion aggregate principal amount of senior secured notes due 2030, or the VGCP 2030 Notes, and together with the VGCP 2029 Notes, the VGCP 2031 Notes and the VGCP 2033 Notes, the VGCP Senior Secured Notes. The VGCP 2030 Notes bear interest at a rate of 6.250% per annum, payable semi-annually in arrears on January 15 and July 15 of each year, beginning July 15, 2023. The VGCP 2030 Notes will mature on January 15, 2030. The aggregate proceeds from these issuances were used to prepay $4.2 billion outstanding under the Calcasieu Pass Credit Facilities. See Item 8.—*Financial Statements and Supplementary Data*—*Note 11 – Debt* of this Form 10-K for further discussion.

Plaquemines Project. In May 2022, our subsidiary, VGPL, obtained approximately $9.6 billion in project financing consisting of an approximately $8.5 billion term loan facility, or the Plaquemines Construction Term Loan, and a $1.1 billion working capital revolving facility, or the Plaquemines Working Capital Facility, or collectively, the Plaquemines Credit Facilities, that matures in May 2029, to fund the development and construction of Phase 1 of the Plaquemines Project. The project financing facilities were upsized in March 2023 to fund the development and construction of Phase 2 of the Plaquemines Project. In the aggregate, the upsized Plaquemines

Credit Facilities, are comprised of an approximately $12.9 billion Plaquemines Construction Term Loan and a $2.1 billion Plaquemines Working Capital Facility, that mature on May 25, 2029 and bear interest at SOFR plus an applicable margin, payable monthly in arrears. In connection with the upsize, PL Holdings entered into the Plaquemines Equity Bridge Facility, an approximately $1.7 billion secured credit facility equity bridge credit facility to fund a portion of project costs for the Plaquemines Project. In July 2024, we prepaid the remaining outstanding amount of the Plaquemines Equity Bridge Facility in full using proceeds from the VGLNG 2030 Notes. The net proceeds from the project financing arrangements will be used be used to fund the costs of financing, developing, constructing, and commissioning the Plaquemines Project. See Item 8.—*Financial Statements and Supplementary Data*—*Note 11 – Debt* of this Form 10-K for further discussion.

Cash Flows

Year Ended December 31, 2024 compared to Year Ended December 31, 2023

The following table shows a summary of our cash flows for the periods indicated:

	Years ended December 31,		Change	
	2024	2023	($)	(%)
Net cash from operating activities	$ 2,149	$ 4,550	$ (2,401)	(53)%
Net cash used by investing activities	(14,159)	(8,725)	(5,434)	62 %
Net cash from financing activities	10,752	7,635	3,117	41 %

Operating activities

Net cash from operating activities during the year ended December 31, 2024 was $2.1 billion, a $2.4 billion, or 53%, decrease from $4.6 billion during the year ended December 31, 2023. The net decrease in cash inflows was primarily due to:

- a decrease of $2.9 billion of cash received for the sale of LNG; and
- an increase of $280 million of cash paid for operating expenses.

These decreases in net cash inflows from operating activities were partially offset by:

- a decrease of $475 million of cash paid for costs of sales, primarily for the purchase of natural gas;
- a decrease of $118 million of cash paid for income taxes; and
- an increase of $88 million of cash received from interest income.

Investing activities

Net cash used by investing activities during the year ended December 31, 2024 was $14.2 billion, a $5.4 billion, or 62%, increase from $8.7 billion during the year ended December 31, 2023. The net increase in cash outflows was primarily due to:

- an increase in cash used for purchases of property, plant and equipment of $5.6 billion primarily related to:
    - an increase in cash paid for construction of $3.0 billion at the Plaquemines Project,
    - $1.4 billion of cash paid for capitalizable equipment and materials at the CP2 Project, and
    - $1.3 billion of cash paid at corporate, primarily for our shipping business and pipeline activities.

Financing activities

Net cash from financing activities during the year ended December 31, 2024 was $10.8 billion, a $3.1 billion, or 41%, increase from $7.6 billion during the year ended December 31, 2023. The net increase in cash inflows was primarily due to:

- a decrease in principal payments on debt of $5.0 billion due to:
  - $905 million of payments during the year ended December 31, 2024 comprised of:
    - the prepayments of $727 million of the Plaquemines Equity Bridge Facility; and
    - the repayments of $178 million of the Calcasieu Pass Credit Facilities;
  - compared to $5.9 billion of principal payments on debt during the year ended December 31, 2023, comprised of:
    - the prepayment of $3.3 billion of a term loan at VGLNG;
    - the prepayments of $1.1 billion of the Calcasieu Pass Credit Facilities;
    - the prepayments of $938 million of the Plaquemines Equity Bridge Facility; and
    - the prepayments of $549 million of a term loan which was jointly held by Legacy VG Partners and VG Commodities;
- an increase in proceeds from project credit facilities of $3.9 billion due to proceeds from the Plaquemines Credit Facilities of $7.8 billion during the year ended December 31, 2024 as compared to proceeds of $3.9 billion during the same period in 2023;
- proceeds from the issuance of VGLNG Series A Preferred Shares of $3.0 billion during the year ended December 31, 2024, with no similar activity during the same period in 2023;
- the repurchase of non-controlling interests (VGLNG common stock) of $1.6 billion during the year ended December 31, 2023, with no similar activity during the same period in 2024; and
- a decrease in payments of financing and debt issuance costs of $449 million due to $142 million of payments during the year ended December 31, 2024, as compared to payments of $591 million during the same period in 2023.

These net increases to cash inflows were partially offset by:

- a decrease in proceeds from the issuance of debt of $10.7 billion due to:
  - $1.6 billion of proceeds during the year ended December 31, 2024 comprised of:
    - proceeds of $1.5 billion from the issuance of the VGLNG 2030 Notes; and
    - proceeds of $84 million from the issuance of other fixed rate debt;
  - compared to $12.3 billion of proceeds during the year ended December 31, 2023 comprised of:
    - proceeds of $9.5 billion from the issuance of the VGLNG 2028 Notes, the VGLNG 2029 Notes, the VGLNG 2031 Notes, and the VGLNG 2032 Notes;
    - proceeds of $1.7 billion from the issuance of the Plaquemines Equity Bridge Facility in connection with FID of Phase 2 of the Plaquemines Project;
    - proceeds of $1.0 billion from the issuance of the VGCP 2030 Notes; and
    - proceeds of $115 million from the upsizing of a term loan jointly held by Legacy VG Partners and VG Commodities.

Year Ended December 31, 2023 compared to Year Ended December 31, 2022

The following table shows a summary of our cash flows for the periods indicated:

	Years ended December 31,		Change	
	2023	2022	($)	(%)
Net cash from operating activities	$ 4,550	$ 3,702	$ 848	23 %
Net cash used by investing activities	(8,725)	(2,900)	(5,825)	201 %
Net cash from financing activities	7,635	235	7,400	NM

NM Percentage not meaningful.

Operating Activities

Net cash from operating activities was $4.6 billion during the year ended December 31, 2023, a $848 million, or 23%, increase from $3.7 billion during the year ended December 31, 2022. The net increase in cash inflows was primarily due to:

- an increase of $1.4 billion of cash proceeds received from test LNG sales produced by the Calcasieu Project assets that were placed in service from an accounting perspective between April and August 2022;
- a $208 million favorable change in cash from the settlement of interest rate swaps due to $203 million in net cash received during the year ended December 31, 2023 as compared to $5 million net cash paid to settle interest rate swaps during the year ended December 31, 2022; and
- an increase of $149 million of cash received from interest income due to larger average cash balances and higher interest rates during the year ended December 31, 2023 as compared to the year ended December 31, 2022.

These increases in cash inflows were partially offset by:

- an increase of $610 million of cash paid for operating expenses primarily due to an increase in development and pre-construction activities related to the CP2 Project that were not capitalizable and operating activities related to the Calcasieu Project, partially offset by a decrease in development activities related to the Plaquemines Project primarily due to it being deemed probable in March 2022, and the costs to develop the facility subsequently being capitalized;
- a net increase of $138 million of cash paid for non-capitalized interest and commitment fees comprised of $129 million at the Calcasieu Project and $18 million at corporate, offset by a decrease of $10 million at the Plaquemines Project; and
- an increase of $128 million of cash paid for income taxes with no similar material activity during the year ended December 31, 2022.

Investing Activities

Net cash used by investing activities was $8.7 billion during the year ended December 31, 2023, a $5.8 billion, or 201%, increase from $2.9 billion during the year ended December 31, 2022. The net increase in cash outflows was primarily due to:

- an increase in cash used for purchases of property, plant and equipment of $3.5 billion related to:
    - an increase in cash paid for construction of the Plaquemines Project of $3.5 billion for costs incurred after the project was deemed probable in March of 2022;
    - an increase of $915 million primarily due to advanced equipment payments related to the CP2 Project; and

  - an increase of $600 million due to advanced equipment payments and capitalized interest payments at corporate.

These increases were partially offset by:

- a decrease at the Calcasieu Project of $1.6 billion since assets were placed in service from an accounting perspective in 2022;
- a decrease in cash proceeds of $1.8 billion from test LNG sales, which was offset against construction in progress, during the year ended December 31, 2022, with no similar cash inflows during the year ended December 31, 2023; and
- an increase in cash outflows of $539 million to purchase equity investments in certain third-party entities for the ultimate acquisition of four LNG tankers.

Financing Activities

Net cash from financing activities was $7.6 billion during the year ended December 31, 2023, a $7.4 billion increase from $235 million during the year ended December 31, 2022. The net increase in cash inflows was primarily due to:

- an increase in proceeds from the issuance of debt of $6.3 billion due to:
  - $12.3 billion of proceeds from debt issuances during the year ended December 31, 2023, comprised primarily of:
    - proceeds of $9.5 billion from the issuance of the VGLNG Senior Secured Notes;
    - proceeds of $1.7 billion from the issuance of the Plaquemines Equity Bridge Facility in connection with FID for Phase 2 of the Plaquemines Project;
    - proceeds of $1.0 billion from the issuance of the 2030 VGCP Senior Secured Notes; and
    - proceeds of $115 million from the upsizing of a term loan jointly held by Legacy VG Partners and VG Commodities;
  - compared to $6.0 billion of proceeds from debt issuances during the year ended December 31, 2022, comprised primarily of:
    - proceeds of $3.2 billion due to the refinancing of a term loan at VGLNG;
    - proceeds of $2.4 billion from debt associated with the Plaquemines Project;
    - an increase in proceeds from the project credit facilities of $2.2 billion due to an increase in proceeds from the Plaquemines Credit Facilities of $2.8 billion, partially offset by a decrease in proceeds from the Calcasieu Pass Credit Facilities of $626 million; and
- a decrease in payments of financing and debt issuance costs of $295 million due to $591 million of payments during the year ended December 31, 2023 compared to debt issuance costs of $886 million during the year ended December 31, 2022.

These net increases to cash inflows were partially offset by:

- an increase in principal payments on debt of $875 million due to:
  - $5.9 billion of repayments during the year ended December 31, 2023 comprised of:
    - the prepayment of $3.3 billion of a term loan at VGLNG;
    - the repayments of $1.1 billion of the Calcasieu Pass Credit Facilities;
    - the prepayments of $938 million of the Plaquemines Equity Bridge Facility; and
    - the prepayment of $549 million of a term loan which was jointly held by Legacy VG Partners and VG Commodities

- compared to $5.0 billion of principal payments on debt during the year ended December 31, 2022, comprised of:
    - the repayment of $3.4 billion for debt associated with the Plaquemines Project;
    - the repayment of $863 million for a convertible note instrument and corresponding embedded derivative liability;
    - the repayment of $385 million due to the refinancing of a term loan at VGLNG; and
    - the repayment of $95 million of the Calcasieu Pass Working Capital Facility.
- an increase in purchases of non-controlling interests of $147 million during the year ended December 31, 2023, as compared to the same period in 2022.

Key Trends and Uncertainties

During 2025 and beyond, we expect to face the following uncertainties related to our business. Management expects that increased operational performance from continued commissioning of our Calcasieu Project and Plaquemines Project may lessen the impacts of these uncertainties. If these favorable effects do not occur, or if the challenges described below have a more significant impact on our business than currently anticipated, then these uncertain adverse factors (or other uncertain adverse factors currently unknown to us) may have a material impact on our income from operations and cash flows. We continue to monitor our operations and address challenges as they arise. For the risk factors related to our business, see Item 1.—*Business* and Item 1A.— *Risk Factors* on this Form 10-K.

Regulatory

The design, construction and operation of our projects, as well as the export of LNG and the transportation of natural gas, are highly regulated activities. The CP2 Project, the CP3 Project, the Delta Project and the potential bolt-on expansion for the Plaquemines Project remain subject to the application for and/or receipt of several material federal, state and local governmental and regulatory approvals and permits. Approvals of FERC and DOE as well as several other material governmental and regulatory approvals and permits, are required in order to construct and operate an LNG facility and a natural gas pipeline, and to export the LNG produced at our projects. See Item 1.—*Business*—*Governmental Regulation*—*Federal Energy Regulatory Commission (FERC)*—*CP2 Project* and Item 1.—*Business*—*Governmental Regulation*—*DOE Export Authorizations* of this Form 10-K.

We cannot predict whether our applications, approvals or permits will attract significant opposition or whether the permitting process will be lengthened due to complexities and appeals, including uncertainty and delays in the timetable on which the DOE will issue the non-FTA export authorization for the CP2 Project. As of December 31, 2024, the carrying value of equipment and materials purchased with the intent of supporting the CP2 Project was $3.5 billion. For further discussion of the FERC regulatory process related to the CP2 Project and DOE export authorizations, see Item 1.—*Business* and Item 1A.— *Risk Factors* of this Form 10-K.

Post-COD SPAs

By design, conventional, stick-built projects generally only engage in several months of commissioning production, thereby limiting the number of cargos produced before full commercial operations occur. Due to our unique modular development approach and configuration consisting of many mid-scale liquefaction trains, which are delivered and installed sequentially, it is necessary to commission and test our LNG facilities sequentially over a longer period of time than traditional LNG facilities with substantially fewer, larger-scale liquefaction trains. The commissioning of the liquefaction trains at our facilities begins while portions of our facilities remain under construction. This important reliability and technical requirement results in earlier production of LNG than with traditional LNG facilities.

The project companies for the Calcasieu Project, the Plaquemines Project and the CP2 Project have executed 39.25 mtpa of LNG under post-COD SPAs that commence after we achieve COD of the relevant project or phase thereof. COD has not yet occurred for any of our LNG projects or phases thereof, and accordingly, LNG revenue recognized during the years ended December 31, 2024, 2023 and 2022, was earned under LNG Commissioning Sales Agreements.

The Calcasieu Project is involved in disputes and arbitration proceedings with certain of its post-COD SPA customers. Such customers are asserting, among other claims, that the Calcasieu Project is delayed in achieving COD under our post-COD SPAs. The remedies sought by these customers include damages ranging between $6.7 billion and $7.4 billion (which is potentially subject to increase with the passage of time until COD occurs), rather than the termination of the post-COD SPA. These disputes are subject to the relevant seller aggregate liability cap of approximately $1.6 billion under the relevant post-COD SPAs. Certain of these customers are also disputing whether the liability limitations in the Calcasieu Project's post-COD SPAs are applicable, and therefore are claiming damages, including amounts in excess of the liability limitations. For further discussion, see Item 1A.—*Risk Factors*—*Risks Relating to Regulation and Litigation*—*If we are unsuccessful in any current or potential future arbitration proceedings with customers, the amounts that we are required to pay may be substantial or certain of our post-COD SPAs may be terminated, which may lead to an acceleration of all our debt for the relevant project* of this Form 10-K.

Macroeconomic Uncertainty

General macroeconomic trends and geopolitical uncertainty may result in conditions that could affect demand and market prices for our products and exacerbate some of the risks that affect our business. This includes heightened inflation, capital market volatility, interest rate and currency rate fluctuations, evolving tax regimes and tariff structures, and changes to environmental and energy policies. Such events may adversely impact the market for corporate bonds and notes or lead the Federal Reserve to raise interest rates in response to concerns about inflation, which may have the effect of increasing our borrowing costs. It is not possible to predict the impact these trends and uncertainties on our consolidated results of operations or financial condition. For further discussion, see Item 1A.—*Risk Factors* of this Form 10-K.

Critical Accounting Policies and Estimates

Use of Estimates

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. We evaluate our assumptions on an ongoing basis. The accounting policies and estimates discussed below are considered by our management to be critical to an understanding of our financial statements as their application requires the most significant judgments from management in estimating matters for financial reporting that are inherently uncertain. While we believe the estimates and assumptions used in the preparation of the consolidated financial statements are appropriate, actual results could differ from these estimates.

Revenue from Contracts with Customers

The transaction price defined in our contracts for the sale of LNG to third-party customers include both fixed and variable components including variable consideration for contingent penalties or fees which may be due from the Company and could result in the significant reversal of revenue. Estimates for penalties or fees are recognized as a reduction to the transaction price until the future significant reversal of revenue is no longer probable of occurring or once the uncertainty is resolved. For further discussion, see Item 8.—*Financial Statements and Supplementary Data*—*Note 4 – Revenue from Contracts with Customers* of this Form 10-K, for more information.

Critical Accounting Policies

Revenue Recognition

The majority of our nameplate capacity produced at the Calcasieu Project and the Plaquemines Project after COD will be sold under long-term 20-year SPAs. We aim to market and sell the expected nameplate capacity at our subsequent projects under a combination of long-term 20-year SPAs as well as short- and medium-term contracts to optimize the average fixed facility charge across our SPAs. Delivery under these post-COD SPAs commences upon achieving COD of the respective LNG facilities, which has not yet occurred for any of our projects. LNG produced prior to an LNG facility achieving COD is sold to various customers under master SPAs, either as single cargos or as multiple cargos to be loaded over a period of time, and are based on spot and/or forward prices at the time of execution.

We recognize revenue when we transfer control of promised goods or services to our customers in an amount that reflects the consideration we expect to be entitled to receive in exchange for those goods or services. Revenue from the sale of LNG is recognized at the point in time when the LNG is delivered to the customer at the agreed upon LNG terminal which is the point when legal title, physical possession and the risks and rewards of ownership transfer to the customer. Each individual molecule of LNG is viewed as a separate performance obligation. Under our projects' LNG sales agreements, LNG may be transferred to the customer on delivery terms including FOB or DPU. When LNG is sold on terms other than FOB, transportation costs incurred by us are considered to be fulfillment costs and are not separate performance obligations within the arrangement. The stated contract price, including both fixed and variable components, is representative of the stand-alone selling price for LNG at the time the contract was negotiated. Sales of LNG commissioning cargos and under our SPAs include variable consideration for contingent penalties or fees which may be due from the Company, and if so, could result in the significant reversal of revenue. Estimates for penalties or fees are recognized as a reduction to the transaction price until the future significant reversal of revenue is no longer probable of occurring or once the uncertainty is resolved. Payment terms are within 30 days after the LNG is delivered.

Proceeds from the sale of test LNG generated during the early commissioning of an LNG project, or test LNG sales, are determined based on estimates of LNG production generated from commissioning activities and recognized as a reduction to the cost basis of construction in progress until assets are placed in service in accordance with the accounting guidance.

Capitalization of Development and Construction Costs

Generally, the costs incurred to develop our LNG facilities are treated as development expenses until construction of the relevant project is considered probable. Costs primarily include professional fees associated with front-end engineering and design work, costs of securing necessary regulatory approvals, and other preliminary investigation and development activities related to our projects. In assessing probability, we consider whether: (i) management has committed to funding construction of the LNG project, (ii) financing for the project is available and (iii) the ability exists to meet the necessary local and other governmental regulations. Certain costs are capitalized prior to a project meeting the criteria otherwise necessary for capitalization, which requires judgment and is based upon our assessment of our ability to realize the future benefits associated with these assets. For example, we have capitalized the cost of equipment and materials that are expected to be used on projects that are not yet probable when the equipment and materials have alternative use and are otherwise recoverable in other projects or for resale. Our construction and equipment supplier arrangements also contain various terms including retainage, performance bonuses, and liquidated damages, that impact the amount and timing of the recognition of the related costs. We capitalized costs of $34.7 billion and $19.4 billion into property, plant, and equipment, net as of December 31, 2024 and 2023, respectively, and recognized development expenses of $635 million, $490 million, and $311 million during the years ended December 31, 2024, 2023 and 2022, respectively. For further discussion, see Item 8.—*Financial Statements and Supplementary Data—Note 6 – Property, Plant and Equipment* of this Form 10-K, for more information.

Derivative Instruments

We reflect all contracts that meet the definition of a derivative, except those designated and qualifying as normal purchase and normal sale, as either assets or liabilities on the consolidated balance sheets at fair value. Changes in the fair value of derivative instruments are recognized in earnings, unless we elect to apply hedge accounting and meet the specified criteria in ASC 815, Derivatives and Hedging. We designate derivatives instruments based on all available facts and circumstances.

We enter into interest rate swap agreements to mitigate volatility arising from changes in interest rates. We do not utilize derivatives for trading or speculative purposes. Derivative instruments are recognized at their fair values on the consolidated balance sheets. Changes in fair value of derivative instruments designated as cash flow hedges are recognized in accumulated other comprehensive income or loss, or AOCL, until the hedged transaction affects earnings, at which time the deferred gains and losses are reclassified to earnings. Cash flows associated with derivatives hedging capitalized interest and designated as cash flow hedges are classified as investing activities in the consolidated statements of cash flows unless the derivatives contain an other-than-insignificant financing element at inception, in which case the associated cash flows are classified as financing activities. Cash flows of our derivatives which are not designated as hedging relationships are classified as operating activities in the consolidated statements of cash flows. Derivative assets and liabilities are presented net on the consolidated balance sheets when a legally enforceable master netting arrangement exists with the counterparty.

We discontinue hedge accounting on a prospective basis if the derivative is no longer expected to be highly effective as a hedge, if the hedged transaction is no longer probable of occurring, or if we de-designate the instrument as a cash flow hedge. Any gain or loss in AOCL at the time of de-designation is reclassified into earnings in the same period the hedged transaction affects earnings unless the underlying hedged transaction is probable of not occurring, in which case, any gain or loss in AOCL is reclassified into earnings immediately. For further discussion, see Item 8.—*Financial Statements and Supplementary Data*—*Note 12 – Derivatives* of this Form 10-K for more information.

Income Taxes

We account for U.S. federal, state and foreign income taxes under the asset and liability method, which requires the recognition of deferred income tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method, we determine income tax assets and liabilities based on the differences between the financial statement and income tax basis for assets and liabilities using the enacted statutory tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in tax rate on deferred income tax assets and liabilities is recognized in income in the period that includes the enactment date.

A valuation allowance is provided for deferred income taxes if it is more-likely-than-not these items will either expire before we are able to realize their benefits or if future deductibility is uncertain. Additionally, we evaluate tax positions under a more-likely-than-not recognition threshold and measurement analysis before the positions are recognized for financial statement reporting.

Our accounting policy for releasing the income tax effects from AOCL occurs on a portfolio basis. For further discussion, see Item 8.—*Financial Statements and Supplementary Data*—*Note 14 – Income Taxes* of this Form 10-K for more information.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Interest Rate Risk

As of December 31, 2024, our exposure to market risk for changes in interest rates related primarily to the Calcasieu Pass Credit Facilities, the Plaquemines Credit Facilities and our investment portfolio. The Calcasieu Pass Credit Facilities and the Plaquemines Credit Facilities accrued interest at term SOFR, plus an applicable margin.

Therefore, fluctuations in interest rates will impact our consolidated financial statements. A rising interest rate environment will increase the amount of interest paid on these loans. We entered into interest rate hedge arrangements to manage our interest rate exposure under the Calcasieu Pass Credit Facilities, and the Plaquemines Credit Facilities. As of December 31, 2024 and December 31, 2023, we had hedges targeting 97% of our variable rate debt for the Calcasieu Project and 80% of our variable rate debt for both phases of the Plaquemines Project. For the years ended December 31, 2024 and 2023, a hypothetical 100 basis point increase in interest rates would have increased our interest cost by $26 million and $12 million, respectively.

The fair value of our credit facilities will generally fluctuate with movements of interest rates, increasing in periods of declining rates of interest and declining in periods of increasing rates of interest. A hypothetical 100 basis point increase or decrease in interest rates would not have had a material impact on the fair value of our credit facilities as of December 31, 2024 and December 31, 2023.

The primary objective of our investment activities is to preserve our capital for the purpose of funding our operations. We do not enter into investments for trading or speculative purposes. We generally invest our cash in investments with short maturities or with frequent interest reset terms. Accordingly, our interest income fluctuates with short-term market conditions. As of December 31, 2024 and December 31, 2023, our investment portfolio consisted of $1.5 billion and $3.4 billion, respectively. Due to the short-term nature of our investment portfolio, our exposure to interest rate risk is minimal.

To the extent we utilize additional debt financing, we may incur fixed or floating rate debt or a combination thereof. We will have exposure to changes in interest rates until such time as the interest rates on any such instruments are determined. We will also have exposure to changes in interest rates with respect to any floating rate debt we incur, unless we enter into interest rate hedges with respect to any such exposure.

Commodity Price Risk

We face commodity price exposure in connection with the construction of our projects, and we expect to also face commodity price exposure during operation of our projects, which we seek to mitigate through certain pricing mechanisms in our SPAs.

In connection with the construction of our projects, our exposure to commodity price risk relates primarily to the commodity fluctuations in the time between when we execute our EPC contract and key owner furnished equipment contracts, and when individual commodity pricing is finalized once procured. Our reimbursable EPC contract target price considers anticipated inflation and models financed contingency to absorb commodity pricing pressure, labor cost increases, and cost overruns for the construction of the relevant project. We expect the potential impacts from commodity price risk will fluctuate with changes in prices of the relevant commodities to be utilized in the construction of the relevant project, which will primarily be steel, aluminum, nickel, concrete and diesel fuel. For our future projects we may be exposed to changes in prices of such commodities if the relevant project is delayed in issuing notice to proceed (or the equivalent) and that delay results in adjustments to the contract price, or if the scope of the project changes subsequent to execution of the contract. We anticipate that the commissioning cargo proceeds expected to be generated by each project will provide additional contingency that is held at the project-level until certain production milestones are achieved and contingency utilization is replenished.

Following the commencement of operations at our projects, our exposure to market risk for changes in commodity prices will relate primarily to the margin we charge our export customers for feed gas under SPAs. Export customers under our existing SPAs will pay a fee equal to a fixed facility charge (which includes a CPI-linked component) per MMBtu, plus a variable commodity charge per MMBtu, in an amount equal to, depending on the applicable SPA, 115% or more of the Henry Hub gas price, which is intended to cover the price of the feed gas and gas transportation costs and is also intended to cover certain of our operating expenses and partially adjust for inflation. We anticipate that any additional LNG contracts we enter into in the future will similarly require our export customers to pay a fixed facility charge per MMBtu, plus a variable commodity charge per MMBtu, in an amount equal to or higher than 115% of the Henry Hub gas price. As a result, changes in the price of feed gas will impact our operating margins. In addition, there may be differences between the actual price we pay for feed gas and the Henry Hub gas price used to calculate the variable commodity charges under the relevant LNG sales contract. Our operating margins would be affected by any such differences.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) are designed to ensure that information required to be disclosed by us in reports we file or submit under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the appropriate time periods, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely discussions regarding required disclosure.

In designing and evaluating our disclosure controls and procedures, management recognizes that any disclosure controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. In addition, the design of disclosure controls and procedures must reflect the fact that there are resource constraints, and that management is required to apply its judgment in evaluating the benefits of possible controls and procedures relative to their costs.

We, under the supervision of and with participation of our management, including our Chief Executive Officer and Chief Financial Officer, have evaluated the effectiveness of our disclosure controls and procedures. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that the design and operation of our disclosure controls and procedures were effective as of December 31, 2024.

Management's Annual Report on Internal Control Over Financial Reporting

This Form 10-K does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of our independent registered public accounting firm due to a transition period established by rules of the SEC for newly public companies.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting during the fiscal quarter ended December 31, 2024 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

In order for a stockholder proposal, submitted pursuant to Rule 14a-8, to be considered timely for inclusion in the Company's proxy statement and form of proxy for the 2025 Annual Meeting of Stockholders, such proposal must be received by the Company at its principal executive office no later than a reasonable time before the Company begins to print and send its proxy materials to stockholders. The Company has determined that March 15, 2025 is a reasonable time before the Company plans to begin printing and mailing its proxy materials. Any proposal received after such date will be considered untimely.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Insider Trading Policies and Procedures

We maintain insider trading policies and procedures governing the purchase, sale, and/or other dispositions of our company's securities by directors, officers, and employees that we believe are reasonably designed to promote compliance with insider trading laws, rules, and regulations, as well as NYSE listing standards. A copy of our insider trading policy is filed as Exhibit 19 to this Form 10-K.

Code of Ethics

Our board of directors has adopted a code of ethics that applies to all of our employees, officers and directors, including our Co-Chairmen, Chief Executive Officer, Chief Financial Officer and other executive and senior financial officers, in accordance with applicable U.S. federal securities laws and the corporate governance rules of NYSE. The full text of our codes of business conduct and ethics is posted on the investor relations section of our website at www.ventureglobal.com. We intend to disclose future amendments to our codes of business conduct and ethics, or any waivers of such code, on our website or in public filings.

Pursuant to paragraph 3 of General Instruction G to Form 10-K, the information required in Item 10 of Part III of this Form 10-K is incorporated by reference from our definitive proxy statement, which will be filed pursuant to Regulation 14A within 120 days after the end of our fiscal year ended December 31, 2024.

ITEM 11. EXECUTIVE COMPENSATION

Pursuant to paragraph 3 of General Instruction G to Form 10-K, the information required in Item 11 of Part III of this Form 10-K is incorporated by reference from our definitive proxy statement, which will be filed pursuant to Regulation 14A within 120 days after the end of our fiscal year ended December 31, 2024.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Pursuant to paragraph 3 of General Instruction G to Form 10-K, the information required in Item 12 of Part III of this Form 10-K is incorporated by reference from our definitive proxy statement, which will be filed pursuant to Regulation 14A within 120 days after the end of our fiscal year ended December 31, 2024.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Pursuant to paragraph 3 of General Instruction G to Form 10-K, the information required in Item 13 of Part III of this Form 10-K is incorporated by reference from our definitive proxy statement, which will be filed pursuant to Regulation 14A within 120 days after the end of our fiscal year ended December 31, 2024.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Our independent registered public accounting firm is Ernst & Young LLP.

Pursuant to paragraph 3 of General Instruction G to Form 10-K, the information required in Item 14 of Part III of this Form 10-K is incorporated by reference from our definitive proxy statement, which will be filed pursuant to Regulation 14A within 120 days after the end of our fiscal year ended December 31, 2024.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as part of this Form 10-K.

(1) *Financial Statements:*

See Item 8.—*Financial Statements and Supplementary Data* above.

(2) *Financial Statement Schedules:*

See Schedule I – Condensed Financial Information of Venture Global, Inc. in Item 15(c) below.

(3) *Exhibits:*

See the exhibits required to be filed or furnished pursuant to Item 601 of Regulation S-K are included in Item 15(b) below.

(b) Exhibits

Exhibit Number	Description
3.1†	Second Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed on January 27, 2025)
3.2	Amended and Restated By-Laws
4.1	Description of Registrant's Securities Registered pursuant to Section 12 of the Securities Exchange Act of 1934
10.1†	Amended and Restated Shareholders' Agreement (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on January 27, 2025)
10.2§†	Second Amended and Restated Engineering, Procurement and Construction Agreement, dated as of January 7, 2022, by and between Venture Global Plaquemines LNG, LLC and KZJV LLC (incorporated by reference to Exhibit 10.2 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.3†	Guaranty Agreement, dated as of April 21, 2021, by KBR, Inc., for the benefit of Venture Global Plaquemines LNG, LLC, pursuant to the Amended and Restated Engineering, Procurement and Construction Agreement, dated as of April 21, 2021, by and between Venture Global Plaquemines LNG, LLC and KZJV LLC (incorporated by reference to Exhibit 10.3 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.4†	Guaranty Agreement, dated as of April 21, 2021, by Zachry Holdings, Inc., for the benefit of Venture Global Plaquemines LNG, LLC, pursuant to the Amended and Restated Engineering, Procurement and Construction Agreement, dated as of April 21, 2021, by and between Venture Global Plaquemines LNG, LLC and KZJV LLC (incorporated by reference to Exhibit 10.4 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.5§†	Limited Notice to Proceed No.1 (ITP), dated as of September 24, 2021, pursuant to the Amended and Restated Engineering, Procurement and Construction Agreement, dated as of April 21, 2021, by and between Venture Global Plaquemines LNG, LLC and KZJV LLC (incorporated by reference to Exhibit 10.5 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.6§†	Change Order No. 1, dated as of May 17, 2022, to the Second Amended and Restated Engineering, Procurement and Construction Agreement, dated as of January 7, 2022, by and between Venture Global Plaquemines LNG, LLC and KZJV LLC (incorporated by reference to Exhibit 10.6 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.7§†	Change Order No. 2, dated as of May 20, 2022, to the Second Amended and Restated Engineering, Procurement and Construction Agreement, dated as of January 7, 2022, by and between Venture Global Plaquemines LNG, LLC and KZJV LLC (incorporated by reference to Exhibit 10.7 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.8§†	Change Order No. 3, dated as of September 30, 2022, to the Second Amended and Restated Engineering, Procurement and Construction Agreement, dated as of January 7, 2022, by and between Venture Global Plaquemines LNG, LLC and KZJV LLC (incorporated by reference to Exhibit 10.8 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.9§†	Amendment No. 1 to the Second Amended and Restated Engineering, Procurement and Construction Agreement, dated as of October 11, 2022, by and between Venture Global Plaquemines LNG, LLC and KZJV LLC (incorporated by reference to Exhibit 10.9 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.10§†	Change Order No. 4, dated as of October 12, 2022, to the Second Amended and Restated Engineering, Procurement and Construction Agreement, dated as of January 7, 2022, by and between Venture Global Plaquemines LNG, LLC and KZJV LLC (incorporated by reference to Exhibit 10.10 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.11§†	Amendment No. 2 to the Second Amended and Restated Engineering, Procurement and Construction Agreement, dated as of February 1, 2023, by and between Venture Global Plaquemines LNG, LLC and KZJV LLC (incorporated by reference to Exhibit 10.11 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.12§†	Change Order No. 5, dated as of March 2, 2023, to the Second Amended and Restated Engineering, Procurement and Construction Agreement, dated as of January 7, 2022, by and between Venture Global Plaquemines LNG, LLC and KZJV LLC (incorporated by reference to Exhibit 10.12 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.13†	Amendment No. 3 to the Second Amended and Restated Engineering, Procurement and Construction Agreement, dated as of September 26, 2023, by and between Venture Global Plaquemines LNG, LLC and KZJV LLC (incorporated by reference to Exhibit 10.13 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.14§†	Amendment No. 4 to the Second Amended and Restated Engineering, Procurement and Construction Agreement, dated as of September 26, 2023, by and between Venture Global Plaquemines LNG, LLC and KZJV LLC (incorporated by reference to Exhibit 10.14 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.15†	Amendment No. 5 to the Second Amended and Restated Engineering, Procurement and Construction Agreement, dated as of January 19, 2024, by and between Venture Global Plaquemines LNG, LLC and KZJV LLC (incorporated by reference to Exhibit 10.15 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)

10.16†	Amendment No. 6 to the Second Amended and Restated Engineering, Procurement and Construction Agreement, dated as of July 2, 2024, by and between Venture Global Plaquemines LNG, LLC and KZJV LLC (incorporated by reference to Exhibit 10.16 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.17§†	Engineering, Procurement and Construction Agreement, dated as of January 10, 2023, by and between Venture Global Plaquemines LNG, LLC and KZJV LLC (incorporated by reference to Exhibit 10.17 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.18†	Guaranty Agreement, dated as of January 10, 2023, by KBR Inc., for the benefit of Venture Global Plaquemines LNG, LLC pursuant to the Engineering, Procurement and Construction Agreement, dated as of January 10, 2023, by and between Venture Global Plaquemines LNG, LLC and KZJV LLC (incorporated by reference to Exhibit 10.18 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.19†	Guaranty Agreement, dated as of January 10, 2023, by Zachry Holdings, Inc., for the benefit of Venture Global Plaquemines LNG, LLC pursuant to the Engineering, Procurement and Construction Agreement, dated as of January 10, 2023, by and between Venture Global Plaquemines LNG, LLC and KZJV LLC (incorporated by reference to Exhibit 10.19 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.20§†	Amendment No. 1 to the Engineering Procurement and Construction Agreement, dated as of September 26, 2023, by and between Venture Global Plaquemines LNG, LLC and KZJV LLC (incorporated by reference to Exhibit 10.20 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.21†	Amendment No. 2 to the Engineering, Procurement and Construction Agreement, dated as of July 2, 2024, by and between Venture Global Plaquemines LNG, LLC and KZJV LLC (incorporated by reference to Exhibit 10.21 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.22§†	Engineering, Procurement and Construction Agreement, dated as of May 12, 2023, by and between Venture Global CP2 LNG, LLC and Worley Field Services, Inc. (incorporated by reference to Exhibit 10.22 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.23†	Guaranty Agreement, dated as of June 8, 2023, by Worley Limited, for the benefit of Venture Global CP2 LNG, LLC, pursuant to the Engineering, Procurement and Construction Agreement, dated as of May 12, 2023, by and between Venture Global CP2 LNG, LLC and Worley Field Services, Inc. (incorporated by reference to Exhibit 10.23 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.24§†	Change Order No. 1, dated as of November 9, 2023, to the Engineering, Procurement and Construction Agreement, dated as of May 12, 2023, by and between Venture Global CP2 LNG, LLC and Worley Field Services, Inc. (incorporated by reference to Exhibit 10.24 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.25§†	Change Order No. 2, dated as of November 30, 2023, to the Engineering, Procurement and Construction Agreement, dated as of May 12, 2023, by and between Venture Global CP2 LNG, LLC and Worley Field Services, Inc. (incorporated by reference to Exhibit 10.25 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.26§†	Change Order No. 3, dated as of February 23, 2024, to the Engineering, Procurement and Construction Agreement, dated as of May 12, 2023, by and between Venture Global CP2 LNG, LLC and Worley Field Services, Inc. (incorporated by reference to Exhibit 10.26 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.27§†	Change Order No. 4, dated as of March 14, 2024, to the Engineering, Procurement and Construction Agreement, dated as of May 12, 2023, by and between Venture Global CP2 LNG, LLC and Worley Field Services, Inc. (incorporated by reference to Exhibit 10.27 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.28§†	Change Order No. 5, dated as of April 1, 2024, to the Engineering, Procurement and Construction Agreement, dated as of May 12, 2023, by and between Venture Global CP2 LNG, LLC and Worley Field Services, Inc. (incorporated by reference to Exhibit 10.28 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.29†	Amendment No. 1 to the Engineering, Procurement and Construction Agreement, dated as of May 10, 2024, by and between Venture Global CP2 LNG, LLC and Worley Field Services, Inc. (incorporated by reference to Exhibit 10.29 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.30§†	Amendment No. 2 to the Engineering, Procurement and Construction Agreement, dated as of May 22, 2024, by and between Venture Global CP2 LNG, LLC and Worley Field Services, Inc. (incorporated by reference to Exhibit 10.30 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.31§†	Change Order No. 6 Rev. 1, dated as of June 17, 2024, to the Engineering, Procurement and Construction Agreement, dated as of May 12, 2023, by and between Venture Global CP2 LNG, LLC and Worley Field Services, Inc. (incorporated by reference to Exhibit 10.31 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.32§†	Fourth Amended and Restated Letter of Agreement, dated as of April 7, 2023, by and between Venture Global LNG, Inc. and Baker Hughes Energy Services LLC (incorporated by reference to Exhibit 10.32 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.33§†	Amended and Restated Purchase Order Contract for the Sale of Liquefaction Train System, dated as of January 19, 2022, by Baker Hughes Energy Services LLC and Venture Global Plaquemines LNG, LLC (incorporated by reference to Exhibit 10.33 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)

10.34†	Guaranty Agreement, dated as of February 26, 2021, by Baker Hughes Holdings LLC, for the benefit of Venture Global Plaquemines LNG, LLC pursuant to the Purchase Order Contract for the Sale of Liquefaction Train System, dated as of February 26, 2021, by and between Baker Hughes Energy Services LLC and Venture Global Plaquemines LNG, LLC (incorporated by reference to Exhibit 10.34 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.35§†	Change Order No. 2, dated as of February 25, 2022, to the Amended and Restated Purchase Order Contract for the Sale of Liquefaction Train System, dated as of January 19, 2022, by and between Baker Hughes Energy Services LLC and Venture Global Plaquemines LNG, LLC (incorporated by reference to Exhibit 10.35 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.36§†	Change Order No. 3, dated as of October 24, 2022, to the Amended and Restated Purchase Order Contract for the Sale of Liquefaction Train System, dated as of January 19, 2022, by and between Baker Hughes Energy Services LLC and Venture Global Plaquemines LNG, LLC (incorporated by reference to Exhibit 10.36 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.37§†	Change Order No. 4, dated as of April 7, 2023, to the Amended and Restated Purchase Order Contract for the Sale of Liquefaction Train System, dated as of January 19, 2022, by and between Baker Hughes Energy Services LLC and Venture Global Plaquemines LNG, LLC (incorporated by reference to Exhibit 10.37 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.38§†	Change Order No. 5, dated as of May 18, 2023, to the Amended and Restated Purchase Order Contract for the Sale of Liquefaction Train System, dated as of January 19, 2022, by and between Baker Hughes Energy Services LLC and Venture Global Plaquemines LNG, LLC (incorporated by reference to Exhibit 10.38 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.39§†	Change Order No. 6, dated as of December 29, 2023, to the Amended and Restated Purchase Order Contract for the Sale of Liquefaction Train System, dated as of January 19, 2022, by and between Baker Hughes Energy Services LLC and Venture Global Plaquemines LNG, LLC (incorporated by reference to Exhibit 10.39 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.40§†	Purchase Order Contract for the Sale of Liquefaction Train System, dated as of August 5, 2022, by and between Baker Hughes Energy Services LLC and Venture Global Plaquemines LNG, LLC (incorporated by reference to Exhibit 10.40 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.41†	Guaranty Agreement, dated as of August 5, 2022, by Baker Hughes Holdings LLC, for the benefit of Venture Global Plaquemines LNG, LLC, pursuant to the Purchase Order Contract for the Sale of Liquefaction Train System, dated as of August 5, 2022, by and between Baker Hughes Energy Services LLC and Venture Global Plaquemines LNG, LLC (incorporated by reference to Exhibit 10.41 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.42§†	Change Order No. 1, dated as of April 7, 2023, to the Purchase Order Contract for the Sale of Liquefaction Train System, dated as of August 5, 2022, by and between Baker Hughes Energy Services LLC and Venture Global Plaquemines LNG, LLC (incorporated by reference to Exhibit 10.42 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.43§†	Change Order No. 2, dated as of May 24, 2023, to the Purchase Order Contract for the Sale of Liquefaction Train System, dated as of August 5, 2022, by and between Baker Hughes Energy Services LLC and Venture Global Plaquemines LNG, LLC (incorporated by reference to Exhibit 10.43 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.44§†	Change Order No. 3, dated as of August 29, 2024, to the Purchase Order Contract for the Sale of Liquefaction Train System, dated as of August 5, 2022, by and between Baker Hughes Energy Services LLC and Venture Global Plaquemines LNG, LLC (incorporated by reference to Exhibit 10.44 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.45§†	Purchase Order Contract for the Sale of Liquefaction Train System, dated as of April 7, 2023, by and between Baker Hughes Energy Services LLC and Venture Global CP2 LNG, LLC (incorporated by reference to Exhibit 10.45 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.46§†	Change Order No. 1, dated as of August 8, 2024, to the Purchase Order Contract for the Sale of Liquefaction Train System, dated as of April 7, 2023, by and between Baker Hughes Energy Services LLC and Venture Global CP2 LNG, LLC (incorporated by reference to Exhibit 10.46 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.47§†	Change Order No. 2, dated as of November 15, 2024, to the Purchase Order Contract for the Sale of Liquefaction Train System, dated as of April 7, 2023, by and between Baker Hughes Energy Services LLC and Venture Global CP2 LNG, LLC (incorporated by reference to Exhibit 10.47 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.48†	Purchase Order Contract for the Sale of Liquefaction Train System, dated as of December 13, 2024 by and between Baker Hughes Energy Services LLC and Venture Global CP2 LNG, LLC (incorporated by reference to Exhibit 10.48 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)

10.49†	Guaranty Agreement, dated as of April 13, 2023, by Baker Hughes Holdings LLC, for the benefit of Venture Global CP2 LNG, LLC, pursuant to the Purchase Order Contract for the Sale of Liquefaction Train System, dated as of April 7, 2023, by and between Baker Hughes Energy Services LLC and Venture Global CP2 LNG, LLC (incorporated by reference to Exhibit 10.49 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.50†	Guaranty Agreement, dated as of May 4, 2023, by Venture Global LNG, Inc., for the benefit of Baker Hughes Energy Services LLC, pursuant to the Purchase Order Contract for the Sale of Liquefaction Train System, dated as of April 7, 2023, by and between Baker Hughes Energy Services LLC and Venture Global CP2 LNG, LLC (incorporated by reference to Exhibit 10.50 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.51§†	Amended and Restated Ground Lease Agreement, dated as of July 15, 2019, by and between Venture Global Calcasieu Pass, LLC and JADP Venture, LLC (incorporated by reference to Exhibit 10.51 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.52§†	First Amendment to Amended and Restated Ground Lease Agreement, dated as of December 12, 2023, by and between Venture Global Calcasieu Pass, LLC and JADP Venture, LLC (incorporated by reference to Exhibit 10.52 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.53§†	Amended and Restated Ground Lease Agreement, dated as of June 20, 2019, by and between Venture Global Calcasieu Pass, LLC and Henry Venture LLC (incorporated by reference to Exhibit 10.53 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.54§†	Ground Lease Agreement, dated as of July 19, 2021, by and between Venture Global Plaquemines LNG, LLC and the Plaquemines Port Harbor and Terminal District (incorporated by reference to Exhibit 10.54 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.55§†	Ground Lease Agreement, dated as of January 19, 2022, by and between Plaquemines Land Ventures, LLC, and the Plaquemines Port Harbor and Terminal District (incorporated by reference to Exhibit 10.55 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.56§†	Amended and Restated Ground Lease Agreement, dated as of September 19, 2023, by and between Cameron Land Ventures, LLC and J.A. Davis Properties, LLC (incorporated by reference to Exhibit 10.56 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.57§†	Ground Lease Agreement, dated of October 12, 2023, by and between Venture Global CP2 LNG, LLC, and Wilma Davis Bride Family, LLC (incorporated by reference to Exhibit 10.57 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.58§†	Ground Lease Agreement, dated as of October 12, 2023, by and between Venture Global CP2 LNG, LLC, and Ardoin Henry, LLC (incorporated by reference to Exhibit 10.58 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.59§†	Ground Lease Agreement, dated as of October 12, 2023, by and between Venture Global CP2 LNG, LLC and Miller Estate Leasing Company, LLC (incorporated by reference to Exhibit 10.59 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.60§†	Ground Lease Agreement, dated as of October 12, 2023, by and between Venture Global CP2 LNG, LLC, and Charlotte Ann LaBove and Carlotta Ann Savoie (incorporated by reference to Exhibit 10.60 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.61§†	Ground Lease Agreement, dated as of October 24, 2023, by and between Venture Global CP2 LNG, LLC and Cameron Parish Port, Harbor and Terminal District (incorporated by reference to Exhibit 10.61 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.62§†	Ground Lease Agreement, dated as of March 11, 2019, by and between Venture Global Calcasieu Pass, LLC and Henry Venture, LLC (incorporated by reference to Exhibit 10.62 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.63§†	Ground Lease Agreement, dated as of December 12, 2023, by and between Venture Global CP2 LNG, LLC and JADP Venture, LLC (incorporated by reference to Exhibit 10.63 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.64§†	Limited Liability Company Agreement, dated as of August 19, 2019, among Calcasieu Pass Funding, LLC and the Members named therein (incorporated by reference to Exhibit 10.64 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.65†	Limited Liability Company Agreement, dated as of August 19, 2019, by and among Calcasieu Pass Holdings, LLC and the Members named therein (incorporated by reference to Exhibit 10.65 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.66†	Amendment No. 1 to the Limited Liability Company Agreement of Calcasieu Pass Funding, LLC, dated as of February 8, 2021 (incorporated by reference to Exhibit 10.66 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.67†	Amendment No. 1 to the Limited Liability Company Agreement of Calcasieu Pass Holdings, LLC, dated as of February 8, 2021 (incorporated by reference to Exhibit 10.67 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)

10.68†	Amendment No. 2 to the Limited Liability Company Agreement of Calcasieu Pass Funding, LLC, dated as of October 27, 2021 (incorporated by reference to Exhibit 10.68 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.69†	Amendment No. 2 to the Limited Liability Company Agreement of Calcasieu Pass Holdings, LLC, dated as of October 27, 2021 (incorporated by reference to Exhibit 10.69 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.70†	Amendment No. 3 to the Limited Liability Company Agreement of Calcasieu Pass Funding, LLC, dated as of July 30, 2022 (incorporated by reference to Exhibit 10.70 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.71†	Amendment No. 3 to the Limited Liability Company Agreement of Calcasieu Pass Holdings, LLC, dated as of July 30, 2022 (incorporated by reference to Exhibit 10.71 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.72§†	Credit Facility Agreement, dated as of August 19, 2019, by and among Venture Global Calcasieu Pass, LLC, TransCameron Pipeline, LLC, the lenders party thereto from time to time, the issuing banks thereto from time to time, Natixis, New York Branch, as credit facility agent, and Mizuho Bank (USA), as collateral agent (incorporated by reference to Exhibit 10.72 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.73§†	Common Terms Agreement for the Loans, dated as of August 19, 2019, by and among Venture Global Calcasieu Pass, LLC, TransCameron Pipeline, LLC, Natixis, New York Branch, as credit facility agent, Mizuho Bank, Ltd., as intercreditor agent, and each other facility agent party thereto from time to time (incorporated by reference to Exhibit 10.73 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.74†	Consent and Amendment to the Common Terms Agreement and the Credit Facility Agreement, dated as of December 28, 2020, in respect of the Common Terms Agreement, dated as of August 19, 2019, and the Credit Facility Agreement, dated as of August 19, 2019 (incorporated by reference to Exhibit 10.74 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.75†	Second Amendment to the Common Terms Agreement and Consent to the Credit Facility Agreement, dated as of January 26, 2021, in respect of the Common Terms Agreement, dated as of August 19, 2019, and the Credit Facility Agreement, dated as of August 19, 2019 (incorporated by reference to Exhibit 10.75 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.76§†	Consent and Amendment to Credit Facility Agreement, dated as of September 30, 2021, in respect of the Credit Facility Agreement, dated as of August 19, 2019 (incorporated by reference to Exhibit 10.76 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.77†	Third Amendment to the Common Terms Agreement, First Amendment to the Common Security and Account Agreement and Consent to the Credit Facility Agreement, dated May 25, 2022, in respect of the Common Terms Agreement, dated as of August 19, 2019, the Common Security and Account Agreement, dated as of August 19, 2019, and the Credit Facility Agreement, dated as of August 19, 2019 (incorporated by reference to Exhibit 10.77 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.78†	Fourth Amendment to the Common Terms Agreement and Second Amendment to the Credit Facility Agreement, dated as of October 12, 2022, in respect of the Common Terms Agreement, dated as of August 19, 2019, and the Credit Facility Agreement, dated as of August 19, 2019 (incorporated by reference to Exhibit 10.78 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.79§†	Fifth Amendment to the Common Terms Agreement and Third Amendment to the Common Security and Account Agreement, dated as of February 27, 2023, in respect of the Common Terms Agreement, dated as of August 19, 2019, and the Common Security and Account Agreement, dated as of August 19, 2019 (incorporated by reference to Exhibit 10.79 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.80†	Third Amendment to the Credit Facility Agreement, dated as of May 26, 2023, in respect of the Credit Facility Agreement, dated as of August 19, 2019 (incorporated by reference to Exhibit 10.80 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.81†	Sixth Amendment to the Common Terms Agreement and Fourth Amendment to the Common Security and Account Agreement, dated as of June 30, 2023, in respect of the Common Terms Agreement, dated as of August 19, 2019, and the Common Security and Account Agreement, dated as of August 19, 2019 (incorporated by reference to Exhibit 10.81 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.82§†	Seventh Amendment to the Common Terms Agreement and Fifth Amendment to the Common Security and Account Agreement, dated as of October 23, 2024, in respect of the Common Terms Agreement, dated as of August 19, 2019, and the Common Security and Account Agreement, dated as of August 19, 2019 (incorporated by reference to Exhibit 10.82 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.83§†	Indenture, dated as of August 5, 2021, by and among Venture Global Calcasieu Pass, LLC, as Issuer, TransCameron Pipeline LLC, as Guarantor, and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the Issuer's 3.875% Senior Secured Notes due 2029 and 4.125% Senior Secured Notes due 2031 (incorporated by reference to Exhibit 10.83 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)

10.84§†	First Supplemental Indenture, dated as of November 22, 2021, by and among Venture Global Calcasieu Pass, LLC, TransCameron Pipeline LLC and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of August 5, 2021 (incorporated by reference to Exhibit 10.84 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.85§†	Second Supplemental Indenture, dated as of January 13, 2023, by and among Venture Global Calcasieu Pass, LLC, TransCameron Pipeline LLC and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of August 5, 2021 (incorporated by reference to Exhibit 10.85 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.86§†	Amended and Restated Credit Facility Agreement, dated as of March 13, 2023, by and among Venture Global Plaquemines LNG, LLC, Venture Global Gator Express, LLC, the lenders party thereto from time to time, the issuing banks thereto from time to time, Natixis, New York Branch, as credit facility agent, and Royal Bank of Canada, as collateral agent (incorporated by reference to Exhibit 10.86 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.87†	Amended and Restated Common Terms Agreement for the Loans, dated as of March 13, 2023, by and among Venture Global Plaquemines LNG, LLC, Venture Global Gator Express, LLC, Natixis, New York Branch, as credit facility agent, and Royal Bank of Canada, as intercreditor agent (incorporated by reference to Exhibit 10.87 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.88†	Amendment No. 1 to the Common Terms Agreement, dated as of September 29, 2023, in respect of the Amended and Restated Common Terms Agreement, dated as of March 13, 2023 (incorporated by reference to Exhibit 10.88 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.89†	Amendment No. 2 to the Common Terms Agreement and Amendment No. 1 to the Common Security and Account Agreement, dated as of May 15, 2024, in respect of the Amended and Restated Common Terms Agreement, dated as of March 13, 2023 (incorporated by reference to Exhibit 10.89 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.90§†	Amendment No. 3 to the Common Terms Agreement, dated as of October 23, 2024, in respect of the Amended and Restated Common Terms Agreement, dated as of March 13, 2023 (incorporated by reference to Exhibit 10.90 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.91†	Indenture, dated as of May 26, 2023, by and between Venture Global LNG, Inc., as Issuer, and The Bank of New York Mellon Trust Company, N.A., as Trustee and Collateral Agent, relating to the Issuer's 8.125% Senior Secured Notes due 2028 and 8.375% Senior Secured Notes due 2031 (incorporated by reference to Exhibit 10.91 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.92†	First Supplemental Indenture, dated as of September 25, 2023, by and between Venture Global LNG, Inc. and The Bank of New York Mellon Trust Company, N.A., relating to the Indenture dated as of May 26, 2023 (incorporated by reference to Exhibit 10.92 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.93†	Second Supplemental Indenture, dated as of September 28, 2023, by and among Venture Global Commodities, LLC, Venture Global LNG, Inc. and The Bank of New York Mellon Trust Company, N.A., relating to the Indenture dated as of May 26, 2023 (incorporated by reference to Exhibit 10.93 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.94§†	Third Supplemental Indenture, dated as of October 24, 2023, by and among Venture Global Commodities, LLC, Venture Global LNG, Inc. and The Bank of New York Mellon Trust Company, N.A., relating to the Indenture, dated as of May 26, 2023 (incorporated by reference to Exhibit 10.94 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.95†	Indenture, dated as of October 24, 2023, by and between Venture Global LNG, Inc., as Issuer, and The Bank of New York Mellon Trust Company, N.A., as Trustee and Collateral Agent, relating to the Issuer's 9.500% Senior Secured Notes due 2029 and 9.875% Senior Secured Notes due 2032 (incorporated by reference to Exhibit 10.95 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.96§†	First Supplemental Indenture, dated as of November 8, 2023, by and between Venture Global LNG, Inc. and The Bank of New York Mellon Trust Company, N.A., relating to the Indenture dated as of October 24, 2023 (incorporated by reference to Exhibit 10.96 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.97†	Indenture, dated as of July 24, 2024, by and between Venture Global LNG, Inc., as Issuer, and The Bank of New York Mellon Trust Company, N.A., as Trustee and Collateral Agent, relating to the Issuer's 7.00% Senior Secured Notes due 2030 (incorporated by reference to Exhibit 10.97 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.98†	Management Services Agreement, dated as of December 1, 2014, by and between Venture Global Commodities, LLC and Venture Global Partners, LLC (incorporated by reference to Exhibit 10.98 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.99†	Second Amended and Restated Management Services Agreement, dated as of April 20, 2015, by and between Venture Global LNG, Inc. and Venture Global Partners, LLC (incorporated by reference to Exhibit 10.99 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.100†	Venture Global LNG, Inc. 9.00% Series A Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock Certificate of Designations filed with the Secretary of the State of Delaware on September 30, 2024 (incorporated by reference to Exhibit 10.100 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)

10.101#†	Venture Global, Inc. 2023 Stock Option Plan (as amended and restated November 14, 2024) (incorporated by reference to Exhibit 10.101 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.102#†	Form of Venture Global, Inc. 2023 Stock Option Plan Non-Qualified Stock Option Agreement (incorporated by reference to Exhibit 10.102 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.103#†	Venture Global, Inc. 2025 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.103 to Amendment No. 1 to the Registrant's Registration Statement on Form S-1 filed on January 13, 2025)
10.104#§†	Executive Employment Agreement, by and between Venture Global LNG, Inc. and Michael Sabel, dated as of January 10, 2025 (incorporated by reference to Exhibit 10.104 to Amendment No. 1 to the Registrant's Registration Statement on Form S-1 filed on January 13, 2025)
10.105#§†	Executive Employment Agreement, by and between Venture Global LNG, Inc. and Jonathan Thayer, dated as of January 10, 2025 (incorporated by reference to Exhibit 10.105 to Amendment No. 1 to the Registrant's Registration Statement on Form S-1 filed on January 13, 2025)
10.106#§†	Executive Employment Agreement, by and between Venture Global LNG, Inc. and Robert Pender, dated as of January 10, 2025 (incorporated by reference to Exhibit 10.106 to Amendment No. 1 to the Registrant's Registration Statement on Form S-1 filed on January 13, 2025)
10.107#§†	Executive Amended and Restated Services Agreement, by and between Venture Global LNG, Inc. and Thomas Earl, dated as of January 10, 2025 (incorporated by reference to Exhibit 10.107 to Amendment No. 1 to the Registrant's Registration Statement on Form S-1 filed on January 13, 2025)
10.108#§†	Executive Employment Agreement, by and between Venture Global LNG, Inc. and Keith Larson, dated as of January 10, 2025 (incorporated by reference to Exhibit 10.108 to Amendment No. 1 to the Registrant's Registration Statement on Form S-1 filed on January 13, 2025)
10.109#§†	Executive Employment Agreement, by and between Venture Global LNG, Inc. and Brian Cothran, dated as of January 10, 2025 (incorporated by reference to Exhibit 10.109 to Amendment No. 1 to the Registrant's Registration Statement on Form S-1 filed on January 13, 2025)
10.110#§†	Executive Employment Agreement, by and between Venture Global LNG, Inc. and Fory Musser, dated as of January 10, 2025 (incorporated by reference to Exhibit 10.110 to Amendment No. 1 to the Registrant's Registration Statement on Form S-1 filed on January 13, 2025)
10.111#†	Form of Restrictive Covenant Agreement (incorporated by reference to Exhibit 10.111 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.112#†	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.112 to the Registrant's Registration Statement on Form S-1 filed on December 20, 2024)
10.113†	Guaranty Agreement, dated as of December 13, 2024, by Baker Hughes Holdings LLC, for the benefit of Venture Global CP2 LNG, LLC pursuant to the Purchase Order Contract for the Sale of Liquefaction Train System, dated as of December 13, 2024, by and between Baker Hughes Energy Services LLC and Venture Global CP2 LNG, LLC (incorporated by reference to Exhibit 10.113 to Amendment No. 1 to the Registrant's Registration Statement on Form S-1 filed on January 13, 2025)
10.114†	Guaranty Agreement, dated as of January 2, 2025, by Venture Global LNG, Inc., for the benefit of Baker Hughes Energy Services LLC, pursuant to the Purchase Order Contract for the Sale of Liquefaction Train System, dated as of December 13, 2024, by and between Baker Hughes Energy Services LLC and Venture Global CP2 LNG, LLC (incorporated by reference to Exhibit 10.114 to Amendment No. 1 to the Registrant's Registration Statement on Form S-1 filed on January 13, 2025)
10.115#†	Form of Venture Global, Inc. 2025 Omnibus Incentive Plan Non-Qualified Stock Option Agreement for Employees, Consultants and Advisers (incorporated by reference to Exhibit 10.115 to Amendment No. 1 to the Registrant's Registration Statement on Form S-1 filed on January 13, 2025)
10.116#†	Form of Venture Global, Inc. 2025 Omnibus Incentive Plan Non-Qualified Stock Option Agreement for Directors (incorporated by reference to Exhibit 10.116 to Amendment No. 1 to the Registrant's Registration Statement on Form S-1 filed on January 13, 2025)
10.117#†	Form of Venture Global, Inc. 2025 Omnibus Incentive Plan Incentive Stock Option Agreement (incorporated by reference to Exhibit 10.117 to Amendment No. 1 to the Registrant's Registration Statement on Form S-1 filed on January 13, 2025)
10.118#†	Form of Venture Global, Inc. 2025 Omnibus Incentive Plan Restricted Stock Unit Agreement for Employees, Consultants and Advisers (incorporated by reference to Exhibit 10.118 to Amendment No. 1 to the Registrant's Registration Statement on Form S-1 filed on January 13, 2025)
10.119#†	Form of Venture Global, Inc. 2025 Omnibus Incentive Plan Restricted Stock Unit Agreement for Directors (incorporated by reference to Exhibit 10.119 to Amendment No. 1 to the Registrant's Registration Statement on Form S-1 filed on January 13, 2025)
10.120#	Venture Global, Inc. Director Compensation Policy
10.121#	Venture Global, Inc. Management Incentive Plan
10.122§	Change Order No. 6, dated as of January 27, 2025, to the Second Amended and Restated Engineering, Procurement and Construction Agreement, dated as of January 7, 2022, by and between Venture Global Plaquemines LNG, LLC and KZJV LLC

10.123§	Eighth Amendment to the Common Terms Agreement, dated as of March 4, 2025, in respect of the Common Terms Agreement, dated as of August 19, 2019
19	Insider Trading Policies and Procedures
21.1	Subsidiaries of the Registrant
23.1	Consent of Independent Registered Public Accounting Firm
31.1	Certification of Principal Executive Officer Pursuant to Rules 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of Principal Financial Officer Pursuant to Rules 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
97	Policy Relating to Recovery of Erroneously Awarded Compensation

† Incorporated by reference.

# Indicates management contract or compensatory plan.

§ Portions of this exhibit have been omitted in compliance with Regulation S-K, Item 601(a)(6) and/or Item 601(b)(10)(iv).

(c) Financial Statement Schedules

Schedule I—Condensed Financial Information Financial Information of Venture Global, Inc.

Note 5 – Subsequent Events

On January 23, 2025, the Parent Company's IPO was declared effective and its Class A common stock began trading on the New York Stock Exchange on January 24, 2025. On January 27, 2025, the Parent Company completed its IPO in which it issued and sold 70 million shares of Class A common stock, par value $0.01. The Parent Company received net proceeds of approximately $1.7 billion, net of underwriting discounts and commissions of $70 million and offering expenses of approximately $10 million.

Following the effectiveness of the Parent Company's registration statement, and prior to the completion of the IPO, the Parent Company effectuated a 4,520.3317-for-one forward stock split of its Class A common stock. In addition, subsequent to the Stock Split and prior to the completion of the IPO, the total number of shares of Class A common stock held by VG Partners, approximately 1.97 billion shares, was converted into an equal number of shares of Class B common stock. The Class A common stock has one vote per share and the Class B common stock has ten votes per share. After the Stock Split, the par value of the Class A common stock remained at $0.01 per share. These condensed financial statements have been retrospectively adjusted to reflect the impact of the Stock Split of the Class A common stock.

Upon the effectiveness of the registration statement for the IPO, the Parent Company's board of directors and stockholders adopted the Venture Global, Inc. 2025 Omnibus Incentive plan (the "Omnibus Incentive Plan"), under which it granted stock options to purchase approximately 14 million shares of its Class A common stock with an exercise price of $25.00 per share to certain of its subsidiary's employees (the "IPO Grants"). The IPO Grants have a 10-year contractual term and vest in equal quarterly installments over a four-year period. The total number of shares of Class A common stock authorized for issuance under the Omnibus Incentive Plan, including the IPO grants, is approximately 172 million, and is subject to annual automatic evergreen increases thereafter. As of the effectiveness of the Omnibus Incentive Plan, all shares that remained available for issuance under the Parent Company's 2023 Plan became available for issuance under the Omnibus Incentive Plan and no further equity awards will be granted under the 2023 Plan. Awards that remained outstanding under the 2023 Plan as of the effectiveness of the Omnibus Incentive Plan will remain outstanding under, and subject to the terms and conditions of, the 2023 Plan.

In connection with the IPO, the Parent Company amended and restated its certificate of incorporation which, among other things, authorized 200 million shares of preferred stock, 4.4 billion shares of Class A common stock and 3.0 billion shares of Class B common stock.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: March 6, 2025

VENTURE GLOBAL, INC.

By: /s/ Michael Sabel
Name: Michael Sabel
Title: Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this Form 10-K has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Michael Sabel Michael Sabel	Chief Executive Officer, Director, Executive Co-Chairman of the Board and Founder	March 6, 2025
/s/ Robert Pender Robert Pender	Executive Co-Chairman, Director, Executive Co-Chairman of the Board, and Founder	March 6, 2025
/s/ Jonathan Thayer Jonathan Thayer	Chief Financial Officer (Principal Financial Officer)	March 6, 2025
/s/ Sarah Blake Sarah Blake	Chief Accounting Officer (Principal Accounting Officer)	March 6, 2025
/s/ Sari Granat Sari Granat	Director	March 6, 2025
/s/ Andrew Orekar Andrew Orekar	Director	March 6, 2025
/s/ Thomas J. Reid Thomas J. Reid	Director	March 6, 2025
/s/ Jimmy Staton Jimmy Staton	Director	March 6, 2025
/s/ Roderick Christie Roderick Christie	Director	March 6, 2025