November 2022

Q3 2022 Investor Presentation

NewFortress energy

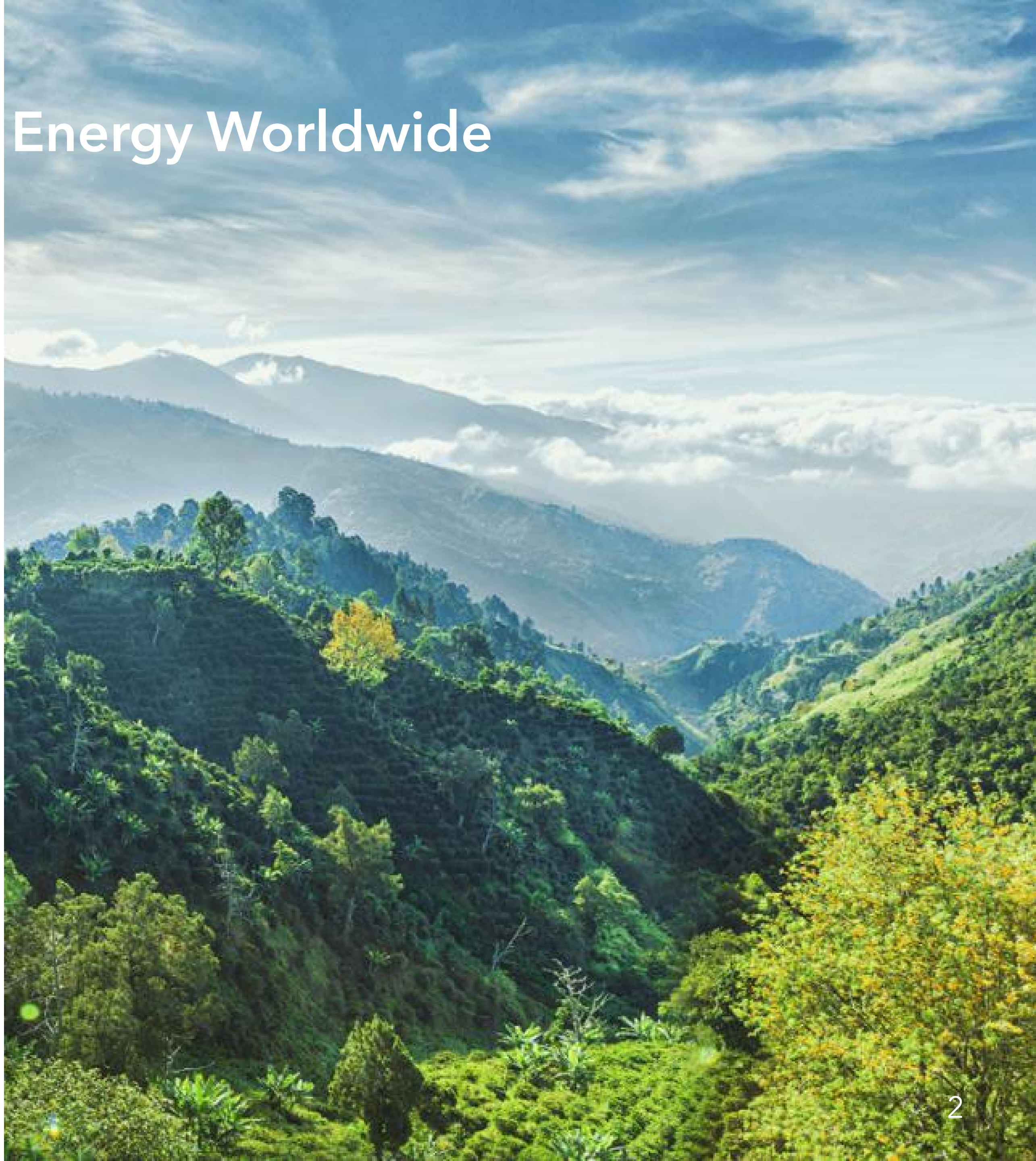
Delivering Positive Energy Worldwide

Our Vision

We want to light the world. Billions of people around the planet lack access to affordable power. Electricity should not be a luxury good.

Our Mission

Our mission is to provide capital, expertise and vision to address this problem while also making positive and meaningful impacts on communities and the environment.



Q3 2022 was another great quarter for the company

We are on track to achieve our Illustrative Adjusted EBITDA Goal[1] of ~$1.1bn for the year

	FY'19	FY'20	FY'21	Q1-22	Q2-22	Q3-22	FY'22	FY'23
							Illustrative Goals[1]	
Total Segment Operating Margin[3]	($21)	$125	$746	$300	$327	$339		
(-) Core SG&A	($94)	($92)	($142)	($42)	($44)	($49)		
Adj. EBITDA[2]	**($115)**	**$33**	**$605**	**$258**	**$283**	**$291**	**~$1.1bn**	**~$2.5bn+**
Net Income (Loss)	*($204)*	*($264)*	*$93*	*$241*	*($178)*	*$56*		

- ✓ Expected deployment[4] of Fast LNG 1
- ✓ Higher operating margins in core business
- ✓ Continued portfolio optimization

Q3 2022 Adj. EBITDA[2] of $291mm

Recently raised our Illustrative Adj. EBITDA Goals[1]:

FY 2022 from $1bn+ to ~$1.1bn

FY 2023 from $1.5bn+ to ~$2.5bn+

(i) Refer to Adj. Net Income reconciliation in Appendix

Historical and projected volumes and margins

	2021	2022[5]	2023
		Illustrative	
Volume[29] (TBtu)	74	88	161
Margin ($/MMBtu)	$8.14	$12.50	$15.53
		Illustrative Goals[1]	
Adj. EBITDA[2] ($mm)	$605	~$1,100	~$2,500

Long-term economics

	2024	2025
	Illustrative	
Volume (TBtu)	336	464
Illustrative margin ($/MMBtu)	Illustrative Adj. EBITDA Goals[1]	
$10.00	$3,360	$4,640
$12.50	$4,200	$5,800
$15.00	$5,040	$6,960

We expect to be able to return significant capital to shareholders

Cash on hand/ lines available[6]

$1.4bn

Targeted operating cash flows next 3 years[7]

~$10bn

We expect to generate $5bn+ of liquidity[8] over the next 3 years

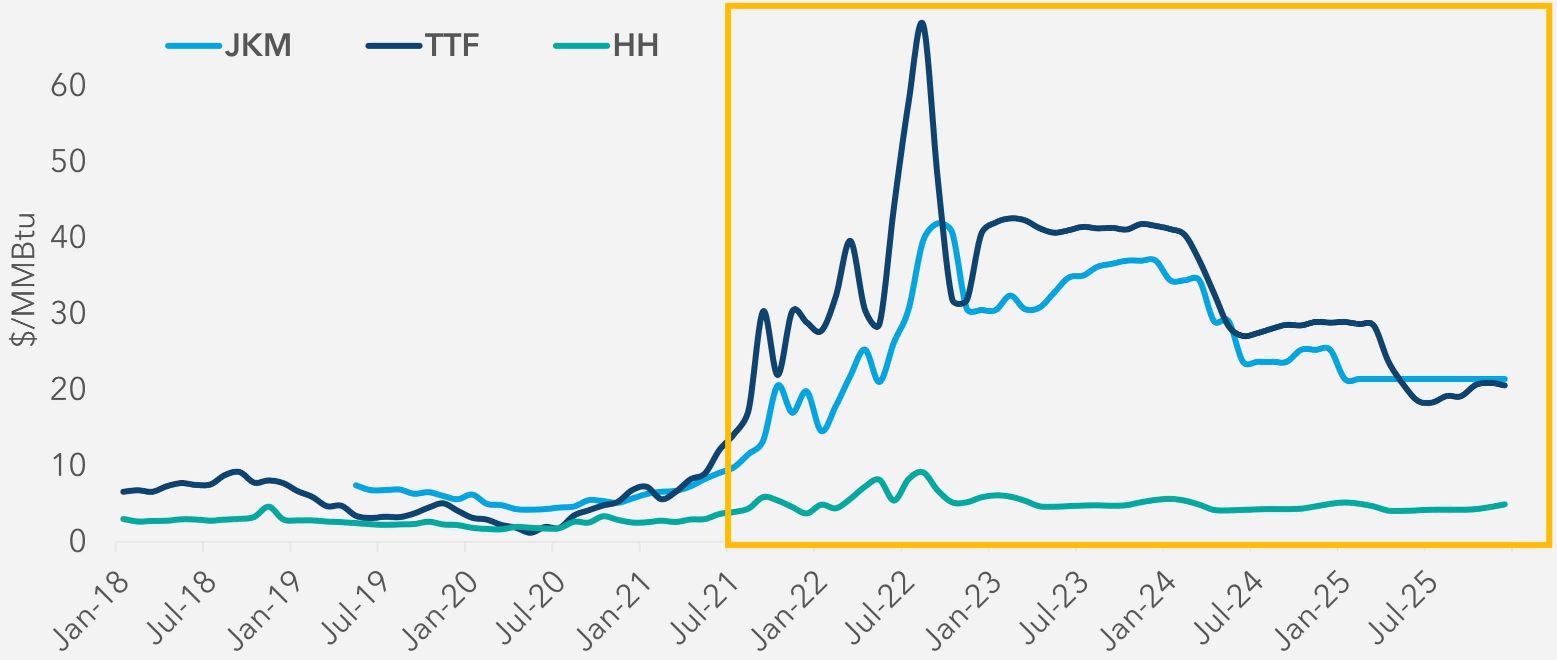
Available liquidity may be used for:

- Additional investments
- Paying down debt
- Issuing dividends

We are evaluating potential updates to our dividend policy[9]

The global LNG market remains significantly undersupplied

Significant & ongoing dislocation between US & global gas prices(i)



$/MMBtu	Today	Last mth	Last qtr	Last yr	2 yrs ago
HH	$6.78	$6.75	$8.06	$5.43	$2.86
TTF	$32.86	$44.86	$58.06	$26.72	$5.62
JKM	$28.93	$35.86	$44.61	$32.15	$6.91

Security of supply issues expected to continue through 2023 and beyond, especially as Asian LNG demand recovers

At current supply levels, **only 70-80% of Europe's gas needs** can be met by year-end 2023

European **gas storage withdrawals typically most pronounced Nov-Mar** (we have not seen the real winter months yet)

European gas infrastructure increasing but not rapidly enough (3 new terminals online by Q1 2023, expected need is for 15-20)

In Asia, there is **another 100+ MTPA of LNG import capacity** proposed and/or under construction

(i) Source: WoodMac, Refinitiv (Eikon), NFE research

Fast LNG: creating supply

NFE expected to add ~ 350 TBtu to our supply portfolio by 2025

NFE LNG supply projections

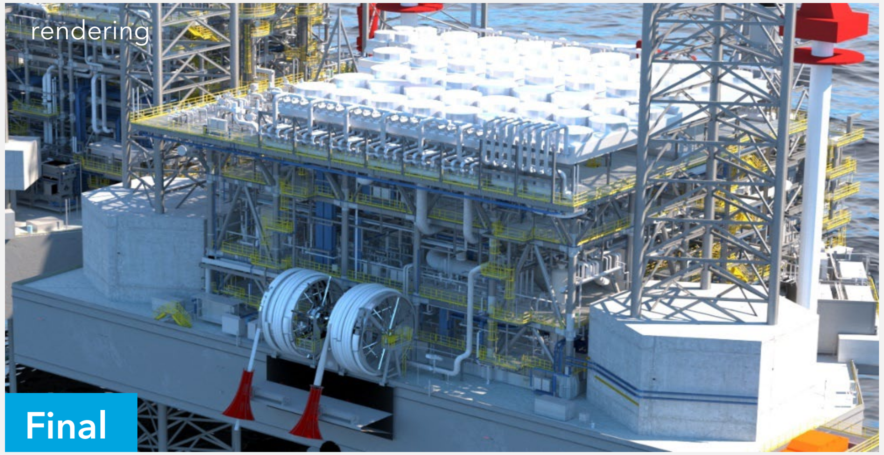
TBtu	2021	2022[5]	2023	2024	2025
Current Supply Contracts[29]	74	88	114	114	114
(+) FLNG Volumes[21]	-	-	47	222	350
Total	74	88	161	336	464

Construction of our first unit is well underway

4.3 million total man hours; 3 million man hours completed with 2,500 people on site

Module fabrication

Our standardized, modular design **accelerates fabrication** timelines & allows **scalability**

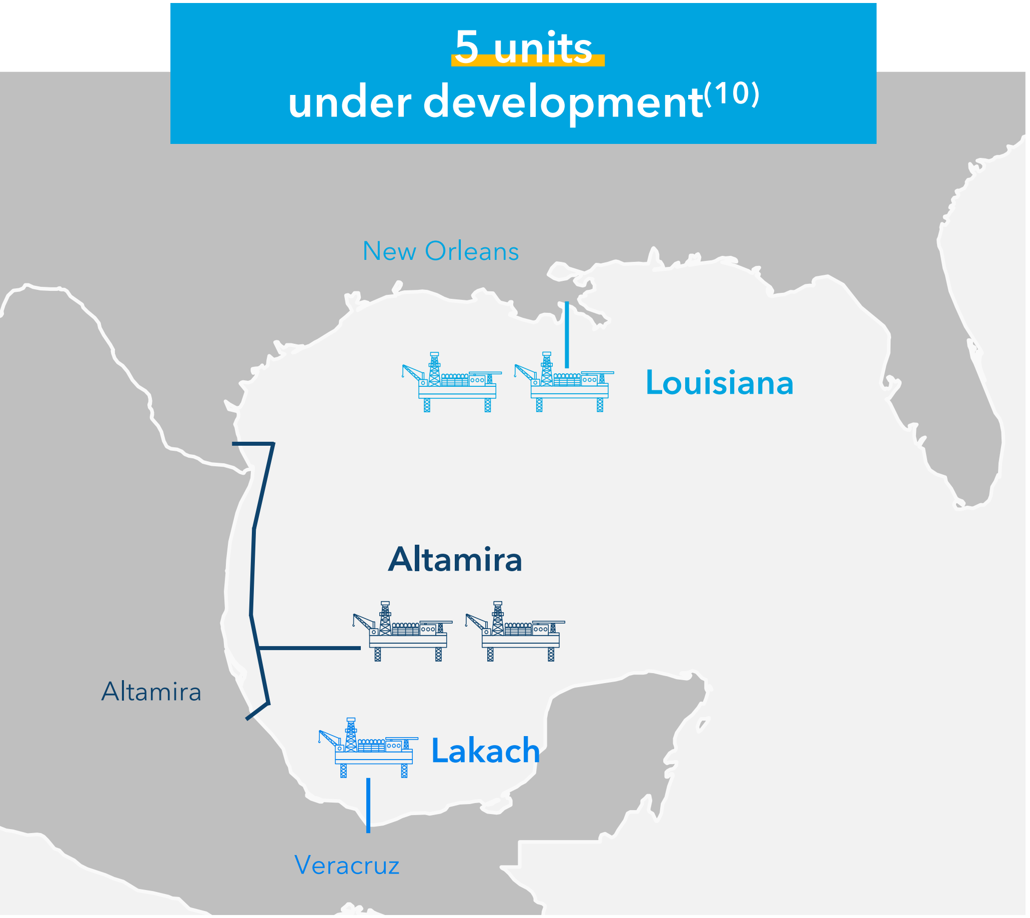


Platform readiness

Fast LNG can utilize a **variety of readily available marine infrastructure**; our first unit uses jack-up rigs

We expect to deploy[(4)] our first Fast LNG unit to Altamira in mid-2023

Definitive agreements for Altamira[(13)] signed in Mexico City on November 3



Altamira

15-year gas supply agreement with CFE[(13)] for new FLNG hub

Existing **Sur de Texas-Tuxpan pipeline to provide access** to gas supply

Louisiana

Progressing permitting with MARAD and USCG[(12)]

Stop clock lifted Oct. 28 following NFE responses to information requests

Lakach

7-well development with Pemex[(14)] in offshore gas field

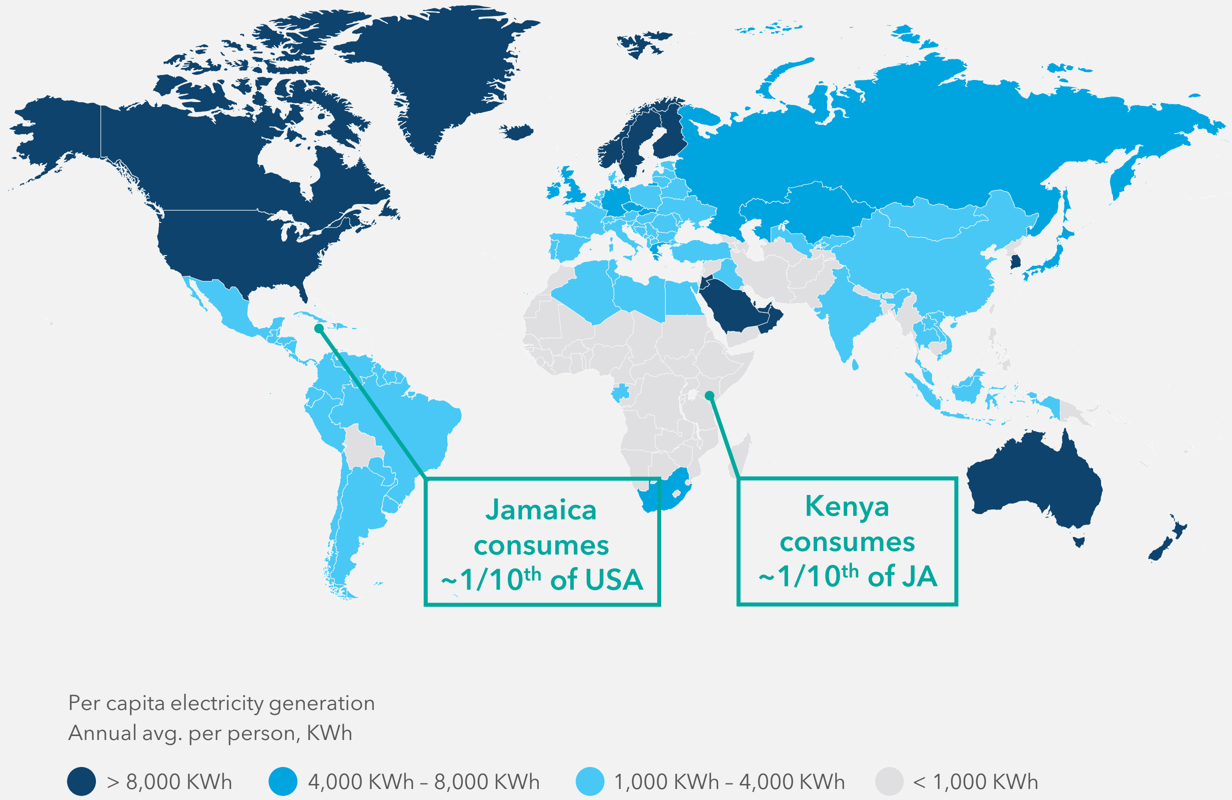
3.5 Tcf of total resource potential when paired with nearby gas reserves

Expect to complete[4] construction on first 5 units by mid-2024

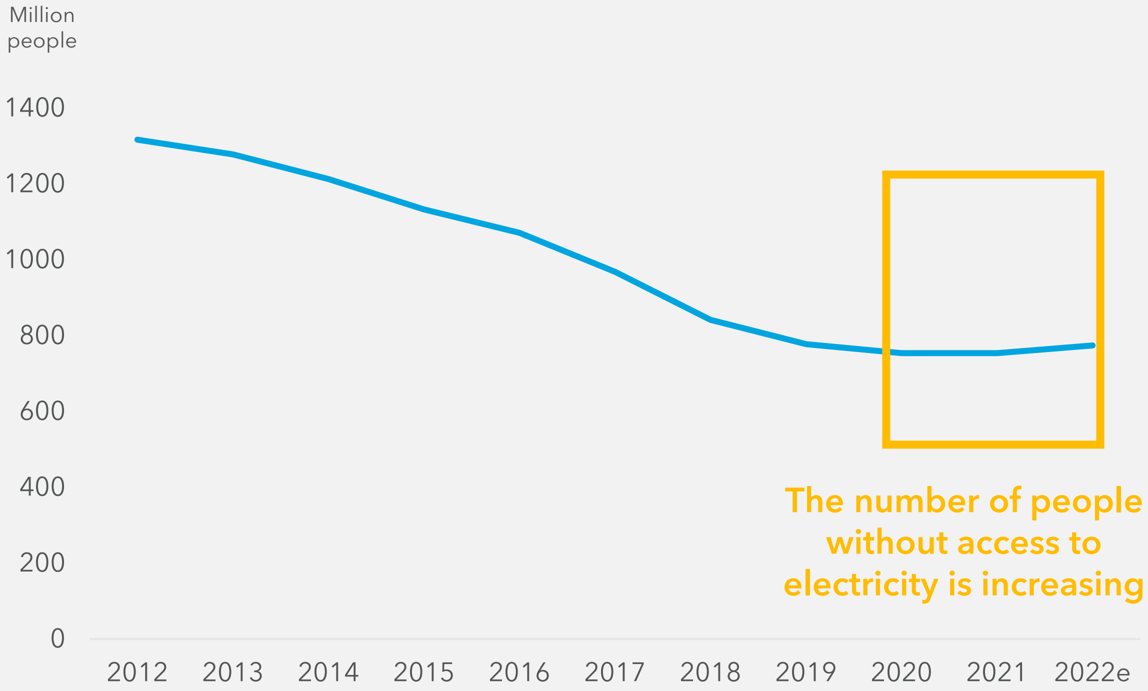
Unit	Design	Construction yard	Mechanical completion[15]
FLNG 1	Jack up rigs	Kiewit Offshore Shipyard	March '23
FLNG 2	Fixed platform	Kiewit Offshore Shipyard	November '23
FLNG 3	Fixed platform	Kiewit Offshore Shipyard / Mexico	January '24
FLNG 4	Sevan Driller	Sembcorp	March '24
FLNG 5	Sevan Brasil	Sembcorp	July '24

Our core mission is to expand access to energy in the places that need it most

Today, over 70% of the world's electricity is consumed by just 10 countries(i)…



…while the number of people without access to electricity is simultaneously set to increase(ii)



(i) The World Bank
(ii) International Energy Agency

Our primary customers are electricity producers

We have acquired, developed, and supplied over 3,000 MW of power capacity since 2016

Acquired/ developed[10]

	Asset	MW	Term	NFE Role
1	Jamalco	100	20	Built / Own
2	Mexico	135	10	Built / Sold
3	Nicaragua	300	25	Built / Own
4	Sergipe	1,600	20	Acquired / Sold

Converted/ LNG supply

	Asset	MW	Term	NFE Role
5	Bogue	145	20	Conversion / Supply
6	Old Harbour	190	20	Conversion / Supply
7	San Juan 5/6[i]	440	10	Conversion / Supply
8	CFE[ii]	200	10	Supply

=

Total 3,110 MW

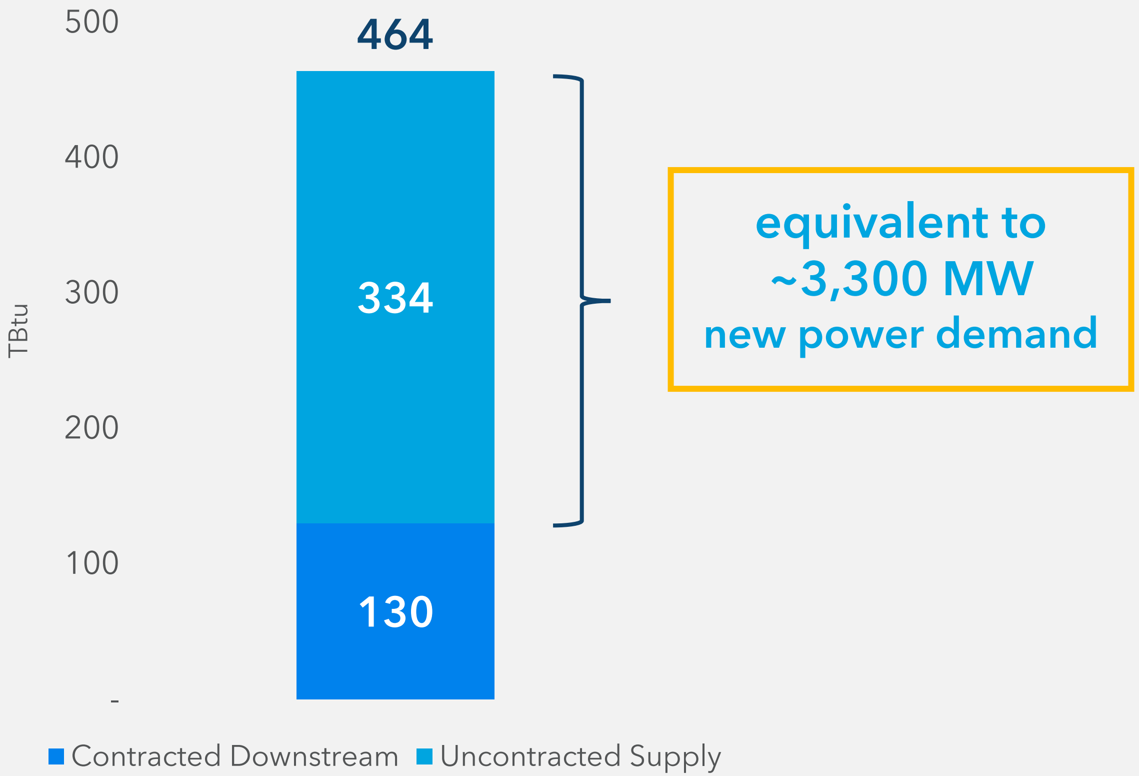
Power supply makes up ~90% of our operational[4] volumes to date

(i) Assumes inclusion of 5 year extension option
(ii) Per agreement executed on November 3 to extend NFE's gas supply agreement with the CFE

Long term, FLNG volumes will fuel new power assets

Rule of thumb: **100 MW ≈ 10 TBtu**

New supply(i) to fuel long-term power demand



Development & in-construction assets

Location	Term	MW
Barcarena	25	600
Ireland	10	600
South Africa	TBD	300
Jamaica	20	200
	Total	**1,700 MW**

Development pipeline

Location	MW
Latin America	1,200
Southeast Asia	2,500
Africa	1,350
Total	**5,050 MW**

(i) 2025+ volumes

Margin example: integrated LNG-to-power

100 MW power plant example[16]

12.5¢	+	2.5¢	=	15¢	=	$17/MMBtu	-	$7/MMBtu	=	$10/MMBtu
Long-term power price[17]		Return on Capex[17]		Total power price[17]		Gas sales price[18]		FLNG supply cost[19]		**Gas margin[20]**

Our historical & expected margins

	2021	2022[5]	2023
		Illustrative	
Volume[29] (TBtu)	74	88	161
Margin ($/MMBtu)	$8.14	$12.50	$15.53
		Illustrative Goals[1]	
Adj. EBITDA[2] ($mm)	**$605**	**~$1,100**	**~$2,500**

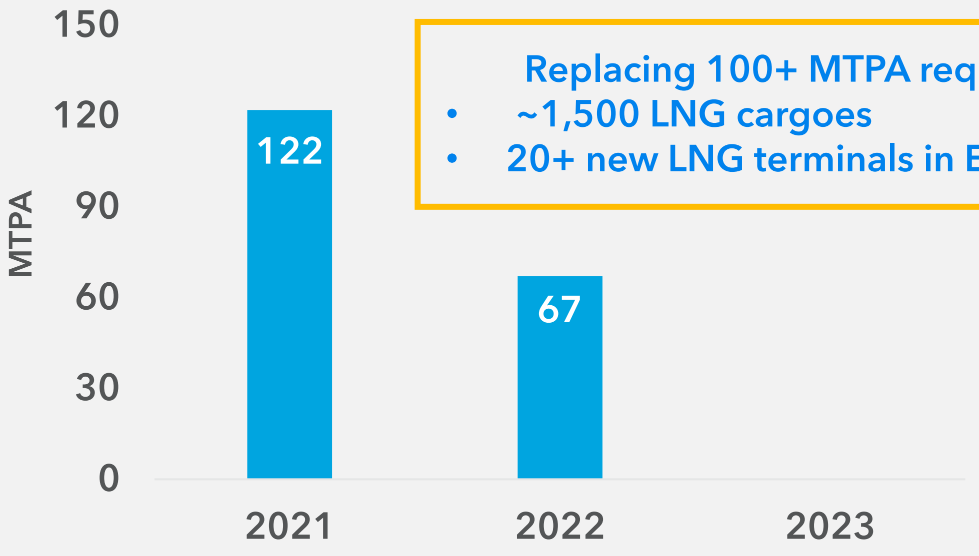
Long-term economics

	Illustrative 2024	Illustrative 2025
Volume (TBtu)	336	464
Illustrative margin ($/MMBtu)	**Illustrative Adj. EBITDA Goals[1]**	
$10.00	**$3,360**	**$4,640**
$12.50	**$4,200**	**$5,800**
$15.00	**$5,040**	**$6,960**

Unprecedented LNG market opportunity in the near term

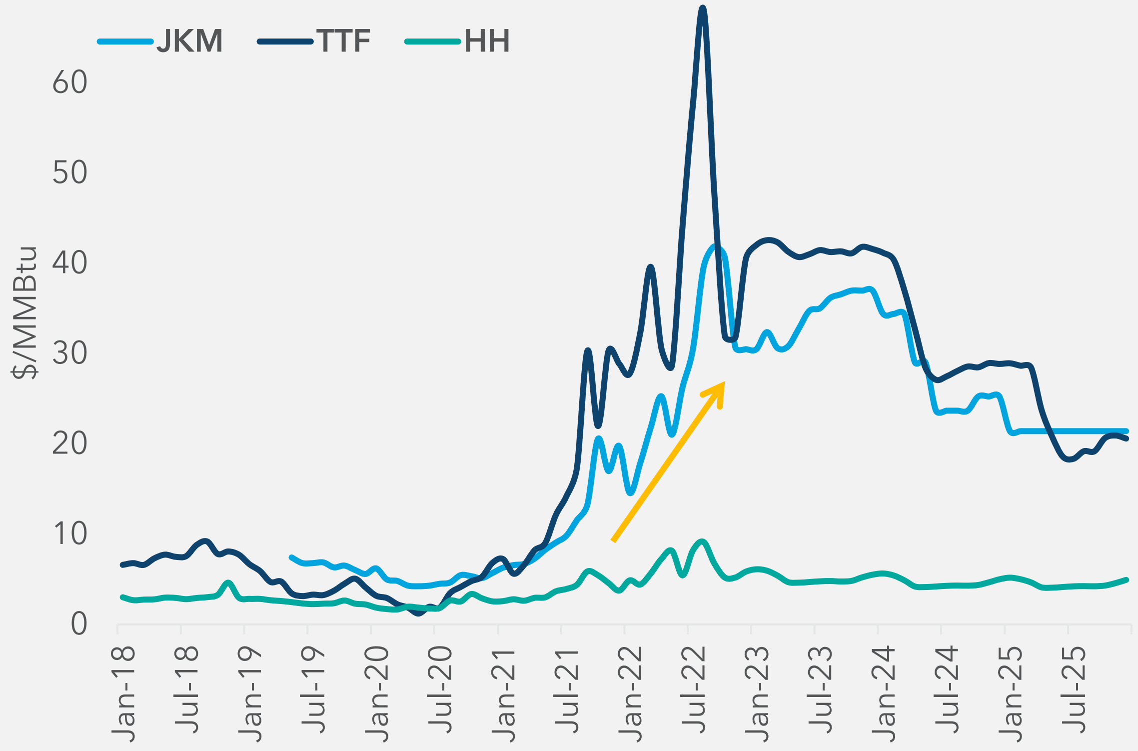
Russian gas previously supplied to Europe has now created a massive supply shortfall…

Russian-supplied pipeline gas to Europe



Replacing 100+ MTPA requires:
- ~1,500 LNG cargoes
- 20+ new LNG terminals in Europe

…& global LNG prices have reacted accordingly



We will connect Fast LNG with re-gas capacity in Europe

Substantial regas infrastructure

30 terminals

~**3,000** LNG cargo slots

Gas priced on a central exchange

"TTF" benchmark pricing index

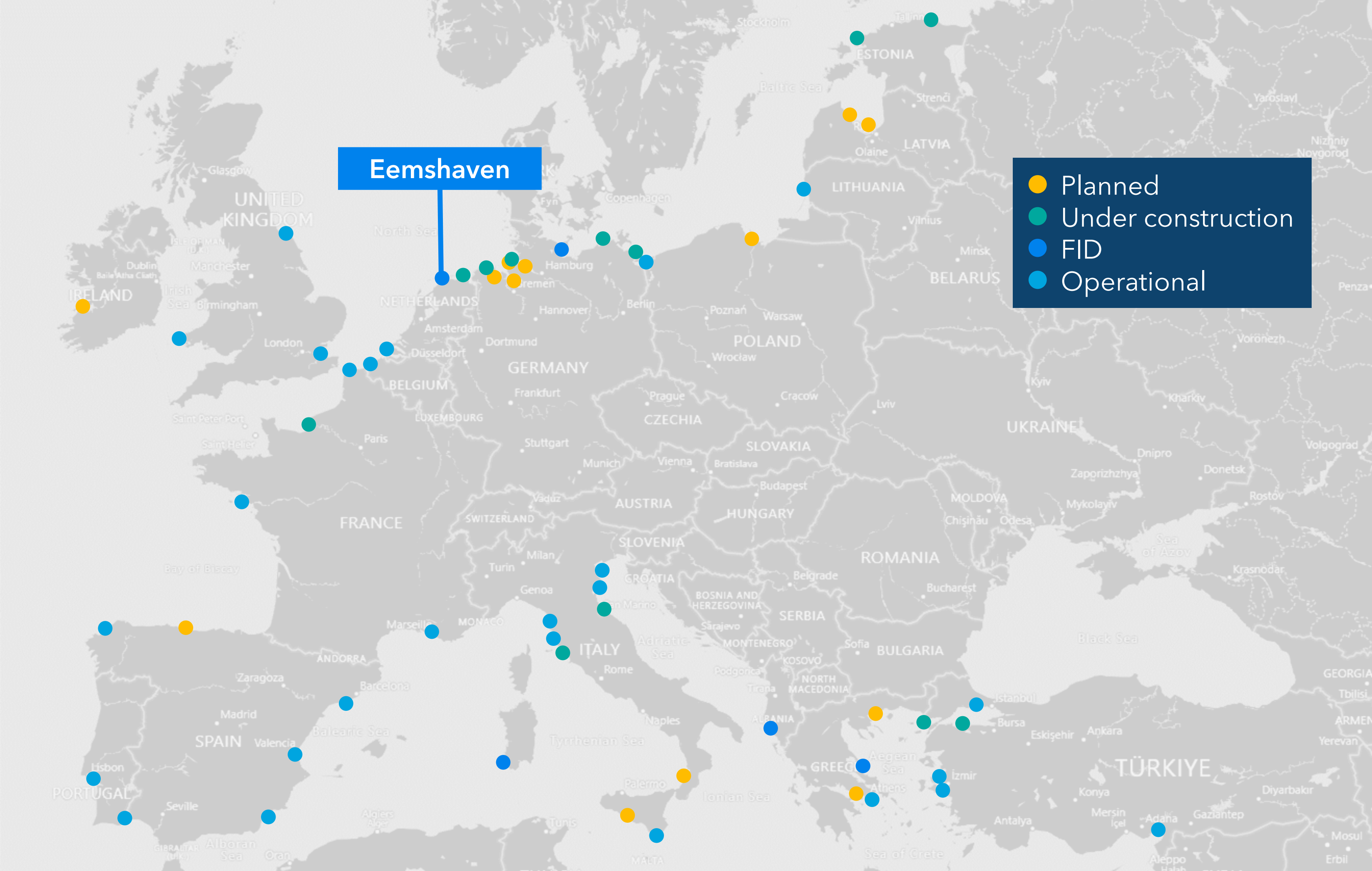
No need to find individual physical buyers

New terminal capacity

Europe replacing over **100 MTPA** of Russian pipeline gas

15-20 new regas terminals

European Regas Terminals



We have started construction[10] on our first hydrogen plant in Beaumont, TX

120 MW green hydrogen plant is expected to be the largest-of-its-kind in the U.S.

During the quarter

Secured electrolyzers and other long-lead items

Executed Entergy MOU[23]: Cost effective, reliable renewable power with future growth opportunities

Advanced negotiations for significant on-site and surrounding offtake

Rendering

Inflation Reduction Act 2022(22) is the largest climate investment in U.S. history

Expected $4+ trillion in capital investment in new U.S. energy supply infrastructure over next 10 years(i)

Annual investment levels expected to significantly increase by 2030(i)

Hydrogen
$4 billion (3x current), $60 billion by 2035 (45x current)

Carbon Capture & Storage (CCS)
$28 billion

Solar
$334 billion (2x current)

Electricity transmission
$46 billion (2x current)

Includes billions in grants, tax credits, & loan programs for batteries, electric vehicles, critical minerals and metals, etc.

What does the legislation offer hydrogen producers?

$3/kg production credit(ii)

Expected to make clean hydrogen production **economic & scalable**

Supports both **green & blue hydrogen**

(i) REPEAT Project, Princeton University ZERO Lab
(ii) Clean hydrogen emitting less than 0.45kg CO_2 per kg of hydrogen; credit available for 10 years post-COD for any project that commences construction by 2033.

ZERO is building a pure-play clean hydrogen infrastructure business

We have a clear path for expansion throughout the U.S. & plan to separately capitalize ZERO in the near-future

zero

Infrastructure anchored by core offtakers, enabling the market for clean hydrogen

Our plan

5
Production hubs

90k
TPA production

2024-2026
Expected online(4) date

Our clean hydrogen hubs are connected to:

- Low-cost renewable power
- Reliable infrastructure
- Advantaged logistics

Financial Results

$291m of Adjusted EBITDA[2] in Q3 2022

On track for FY'22 Illustrative Adj. EBITDA Goal[1] of ~$1.1bn+

	Q3 2021	Q3 2022	YoY Change
Total Seg. Revenue *($mm)*	$465	**$799**	*$322*
Total Seg. Op. Margin[3] *($mm)*	$210	**$339**	*$129*
(-) Core SG&A *($mm)*	($41)	**($49)**	*($8)*
Adj. EBITDA[2] *($mm)*	$170	**$291**	*$122*
Adj. Net (Loss) Income[24] *($mm)* *(excluding non-cash impairment charge)*	($10)	**$86**	*$96*
Adj. EPS[24] *($/share), Diluted* *(excluding non-cash impairment charge)*	($0.05)	**$0.41**	*$0.46*
Net (Loss) Income *($mm)* *(attributable to stock holders)*	($10)	**$62**	*$72*
EPS *($/share), Diluted*	($0.05)	**$0.29**	*$0.34*

- **$291mm of Adj. EBITDA[2]** for Q3 2022; on track for Illustrative Adj. EBITDA Goal[1] of **~$1.1bn+ for FY 2022**
- LTM **Adj. EBITDA[2] of $1.2bn**
- Adjusted EPS[24] of **$0.41** when excluding one-time items
- Sold **23 TBtu** at **$15/MMBtu** in Q3

Simplified balance sheet with ample liquidity to fund[8] Fast LNG

CELSE and ship asset sales successfully closed[25][26], simplifying NFE's capital structure and improving liquidity position

	Q2 2022	Now
	$mm	*$mm*
NFE corporate debt	$3,165	$2,750
Ship debt	$760	-
CELSE debt	$575	-
Jamalco financing	$222	$222
Total debt[i]	**$4,722**	**$2,972**
Cash on hand[6]	$138	$818
Availability under revolver & LOC	$26	$626
Total liquidity	**$164**	**$1,444**

Transactions removed asset level debt and simplified NFE's balance sheet

Substantial liquidity enables NFE to fund[8] Fast LNG units with no required financings

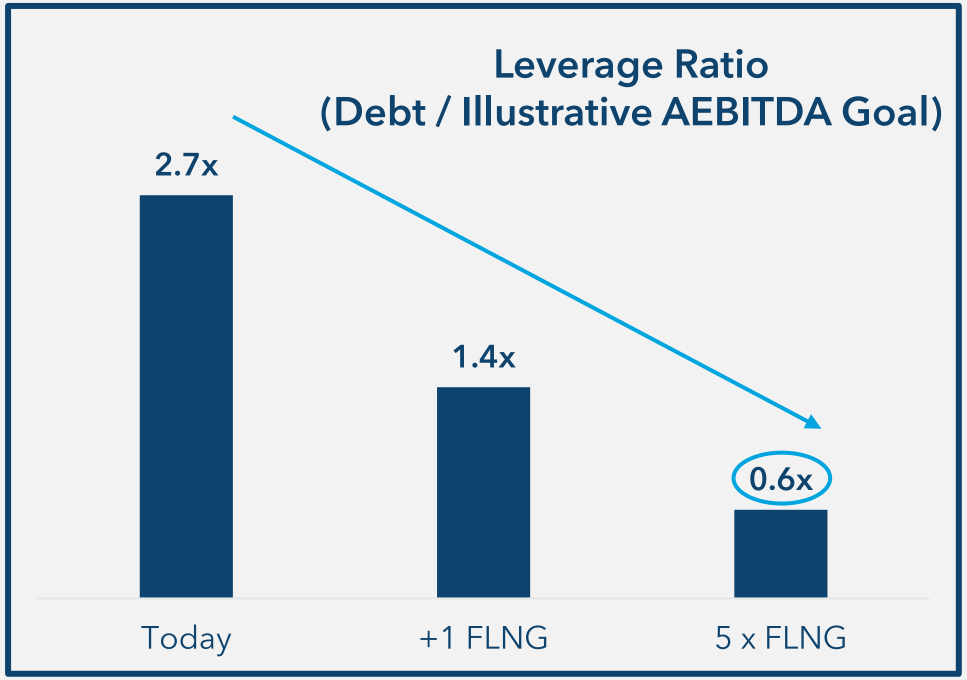
(i) Excludes $100M of asset-level debt for the Barcarena Power Plant, $1.4BN of vessel financing transaction debt with Energos Infrastructure, and $332M of the Hilli Sale Leaseback obligation.
(ii) Includes net proceeds from CELSE asset sale

Our long-term goal: path to investment grade

What does our leverage look like status quo?

	Today	2024 run-rate[27]
	7 Terminals	9 Terminals + 5x FLNG units
	$1.1bn Illustrative Adj. EBITDA Goal[1]	~$5bn Illustrative Adj. EBITDA Goal[1]
	$3bn Debt[i]	$3bn Debt[i]
	<3x Leverage	<1x Targeted leverage

How do we get there?



1. Cash on hand[6]

$1.4bn cash on hand post CELSE[25] & ship transaction[26] and inclusive of available revolver capacity

2. Capex

Our **capex plans are expected to be fully funded** through a combination of cash on hand[6], revolver capacity, and targeted funds from operations[8]

(i) Excludes $100M of asset-level debt for the Barcarena Power Plant, $1.4BN of vessel financing transaction debt with Energos Infrastructure, and $332M of the Hilli Sale Leaseback obligation.

Q3 2022 Operational highlights

Key operational highlights

Volumes delivered

- **Met 100% of nominated quantity** from our customers
- **Optimized customer underconsumption to deliver excess volumes to market** after meeting the required nominations
- **Miami liquefier averaged production of 80k GPD** after fixing cold box issues which allowed it to displace 0.3 TBtu of Jamaica volumes adding to total cargo sales

Asset reliability

- **Reliable[28] for 98% of Q3** across its 4 major terminal operations
- Able to recover and **ready to deliver LNG within 24 hrs. of Hurricane Fiona** passing in Puerto Rico while adhering to USCG guidelines for safe operations
- **Met 100% of total customer nominations** on time

HSSEQ

- Total of **0 significant safety incidents** during Q3'2022
- Took steps to **improve company wide training** with NFE University
- **Completed all FERC submissions** for SJPR

Operational scorecard

Delivered Volumes (Terminals + Cargo Sales)	3.0mm GPD (23 TBtu)
Asset Reliability[28]	98%
HSSEQ (Significant Incidents)	0 incidents
Total Segment Operating Margin[3]	$339mm

We continue to execute on our commercial plan

Key highlights

Terminals

- Ireland terminal and 600 MW power – permit expected by YE2022[10]
- Barcarena terminal complete[4]; ready for 2023 operations[4]
- Santa Catarina terminal expected completion Q4 2022[4]

Power plants

- Binding short-term agreements with CFE[13] to sell 135 MW power plant in La Paz
- Mitsubishi and Toyo mobilized to site under fixed-price EPC for 605 MW Barcarena power plant – operations[4] in Q2 2025
- Closed sale of 50% stake in Sergipe power plant with Eneva for ~$1.3bn, raising ~$530mm in proceeds to NFE[25]

LNG vessels

- Energos Infrastructure[26] - closed JV with Apollo for $2bn enterprise value; Sold ships into JV with long-term charters to NFE
- Started operations[4] of Eems Energy Terminal (Netherlands) utilizing the FSRU Energos Igloo
- Terminal expected to increase LNG capacity near-term with NFE as potential new capacity holder of terminal re-gas slots

Commercial scorecard

2023 Run-rate[27] volumes	4.5mm GPD (136 TBtu)
Contracts[i]	65
Weighted average contract life[ii]	15 years

	2021	2022 Illustrative Goals[1]
Volume[29] (TBtu)	74	88
Adj. EBITDA[2] ($mm)	$605	$1,100
$/MMBtu	$8.14	$12.50

(i) Includes commercial agreement for sale of gas and/or power
(ii) Assumes San Juan 5+6 renewal option
(iii) Assumes 7% discount factor on contracted revenues; includes committed power plant revenue contracts

Segment operating margin reconciliation

Three Months Ended September 30, 2022

(in thousands of $)	Terminals and Infrastructure [1]	Ships [2]	Total Segment	Consolidation and Other [3]	Consolidated
Total revenues	687,437	111,660	799,097	(67,167)	731,930
Cost of sales	402,458	-	402,458	(8,628)	393,830
Vessel operating expenses	3,431	23,799	27,230	(6,912)	20,318
Operations and maintenance	30,079	-	30,079	(8,046)	22,033
Consolidated Segment Operating Margin	**251,469**	**87,861**	**339,330**	**(43,581)**	**295,749**
Less:					
Selling, general and administrative					67,601
Transaction and integration costs					5,620
Depreciation and amortization					35,793
Asset impairment expense					-
Interest expense					63,588
Other expense, net					10,214
Loss on extinguishment of debt, net					14,997
Tax provision					9,971
Loss from equity method investments					31,734
Net income					**56,231**

(1) Terminals and Infrastructure includes the Company's effective share of revenues, expenses and operating margin attributable to 50% ownership of CELSEPAR. The losses attributable to the investment of $44,559 for the three months ended September 30, 2022 are reported in (Loss) income from equity method investments in the condensed consolidated statements of operations and comprehensive income (loss).
(2) Ships includes the Company's effective share of revenues, expenses and operating margin attributable to 50% ownership of the Hilli Common Units. The earnings attributable to the investment of $12,825 for the three months ended September 30, 2022 are reported in (Loss) income from equity method investments in the condensed consolidated statements of operations and comprehensive income (loss).
(3) Consolidation and Other adjusts for the inclusion of the effective share of revenues, expenses and operating margin attributable to 50% ownership of CELSEPAR and Hilli Common Units in the segment measure and exclusion of the unrealized mark-to-market gain or loss on derivative instruments.

Segment operating margin reconciliation

Three Months Ended June 30, 2022

(in thousands of $)	Terminals and Infrastructure [1]	Ships [2]	Total Segment	Consolidation and Other [3]	Consolidated
Total revenues	543,455	111,024	654,479	(69,624)	584,855
Cost of sales	271,948	-	271,948	453	272,401
Vessel operating expenses	4,255	21,288	25,543	(6,915)	18,628
Operations and maintenance	29,540	-	29,540	(9,050)	20,490
Consolidated Segment Operating Margin	**237,712**	**89,736**	**327,448**	**(54,112)**	**273,336**
Less:					
Selling, general and administrative					50,310
Transaction and integration costs					4,866
Depreciation and amortization					36,356
Asset impairment expense					48,109
Interest expense					47,840
Other (income), net					(22,102)
Tax benefit					(86,539)
(Income) from equity method investments					372,927
Net income					**(178,431)**

[1] Terminals and Infrastructure includes the Company's effective share of revenues, expenses and operating margin attributable to 50% ownership of CELSEPAR. The loss attributable to the investment of $389,996 for the three months ended June 30, 2022 are reported in (Loss) income from equity method investments in the condensed consolidated statements of operations and comprehensive income (loss). Terminals and Infrastructure does not include the unrealized mark-to-market loss on derivative instruments of $2,247 for the three months ended June 30, 2022 reported in Cost of sales.

[2] Ships includes the Company's effective share of revenues, expenses and operating margin attributable to 50% ownership of the Hilli Common Units. The earnings attributable to the investment of $17,069 for the three months ended June 30, 2022, are reported in (Loss) income from equity method investments in the condensed consolidated statements of operations and comprehensive income (loss).

[3] Consolidation and Other adjusts for the inclusion of the effective share of revenues, expenses and operating margin attributable to 50% ownership of CELSEPAR and Hilli Common Units in our segment measure and exclusion of the unrealized mark-to-market gain or loss on derivative instruments.

Segment operating margin reconciliation

Three Months Ended March 31, 2022

(in thousands of $)	Terminals and Infrastructure (1)	Ships (2)	Total Segment	Consolidation and Other (3)	Consolidated
Total revenues	480,349	114,942	595,291	(90,173)	505,118
Cost of sales	235,532	-	235,532	(27,234)	208,298
Vessel operating expenses	3,492	25,942	29,434	(6,470)	22,964
Operations and maintenance	30,242	-	30,242	(7,074)	23,168
Consolidated Segment Operating Margin	**211,083**	**89,000**	**300,083**	**(49,395)**	**250,688**
Less:					
Selling, general and administrative					48,041
Transaction and integration costs					1,901
Depreciation and amortization					34,290
Interest expense					44,916
Other (income), net					(19,725)
Tax benefit					(49,681)
(Income) from equity method investments					(50,235)
Net income					**241,181**

(1) Terminals and Infrastructure includes the Company's effective share of revenues, expenses and operating margin attributable to 50% ownership of CELSEPAR. The earnings attributable to the investment of $36,680 for the three months ended March 31, 2022 are reported in income from equity method investments in the condensed consolidated statements of operations and comprehensive income (loss). Terminals and Infrastructure does not include the unrealized mark-to-market gain on derivative instruments of $2,492 for the three months ended March 31, 2022 reported in Cost of sales.
(2) Ships includes the Company's effective share of revenues, expenses and operating margin attributable to 50% ownership of the Hilli Common Units. The earnings attributable to the investment of $13,555 for the three months ended March 31, 2022, are reported in income from equity method investments in the condensed consolidated statements of operations and comprehensive income (loss).
(3) Consolidation and Other adjusts for the inclusion of the effective share of revenues, expenses and operating margin attributable to 50% ownership of CELSEPAR and Hilli Common Units in our segment measure and exclusion of the unrealized mark-to-market gain or loss on derivative instruments.

Segment operating margin reconciliation

Three Months Ended December 31, 2021

(in thousands of $)	Terminals and Infrastructure (1)	Ships (2)	Total Segment	Consolidation and Other (3)	Consolidated
Total revenues	689,770	117,796	807,566	(158,935)	648,631
Cost of sales	382,816	-	382,816	(100,339)	282,477
Vessel operating expenses	3,442	23,000	26,442	(5,466)	20,976
Operations and maintenance	25,158	-	25,158	(6,802)	18,356
Consolidated Segment Operating Margin	**278,354**	**94,796**	**373,150**	**(46,328)**	**326,822**
Less:					
Selling, general and administrative					74,927
Transaction and integration costs					2,107
Depreciation and amortization					30,297
Interest expense					46,567
Other (income), net					(3,692)
Tax provision					5,403
Loss from extinguishment of debt					10,975
Loss from equity method investments					8,515
Net income					**151,723**

(1) Terminals and Infrastructure includes the Company's effective share of revenues, expenses and operating margin attributable to 50% ownership of CELSEPAR. The losses attributable to the investment of $18,580 for the three months ended December 31, 2021 are reported in loss from equity method investments on the consolidated statements of operations and comprehensive income (loss). Terminals and Infrastructure does not include the unrealized mark-to-market loss on derivative instruments of $472 for the three months ended December 31, 2021 reported in Cost of sales.
(2) Ships includes the Company's effective share of revenues, expenses and operating margin attributable to 50% ownership of the Hilli Common Units. The earnings attributable to the investment of $10,065 for the three months ended December 31, 2021 are reported in loss from equity method investments on the condensed consolidated statements of operations and comprehensive income (loss).
(3) Consolidation and Other adjusts for the inclusion of the effective share of revenues, expenses and operating margin attributable to 50% ownership of CELSEPAR and Hilli Common Units in our segment measure and exclusion of the unrealized mark-to-market gain or loss on derivative instruments.

Segment operating margin reconciliation

Year Ended December 31, 2021

(in thousands of $)	Terminals and Infrastructure (1)	Ships (2)	Total Segment	Consolidation and Other (3)	Consolidated
Total revenues	1,366,142	329,608	1,695,750	(372,940)	1,322,810
Cost of sales	789,069	-	789,069	(173,059)	616,010
Vessel operating expenses	3,442	64,385	67,827	(16,150)	51,677
Operations and maintenance	92,424	-	92,424	(19,108)	73,316
Consolidated Segment Operating Margin	**481,207**	**265,223**	**746,430**	**(164,623)**	**581,807**
Less:					
Selling, general and administrative					199,881
Transaction and integration costs					44,671
Depreciation and amortization					98,377
Interest expense					154,324
Other (income), net					(17,150)
Tax provision					12,461
Loss from extinguishment of debt					10,975
(Income) from equity method investments					(14,443)
Net income					**92,711**

(1) Terminals and Infrastructure includes the Company's effective share of revenues, expenses and operating margin attributable to 50% ownership of CELSEPAR. The losses attributable to the investment of $17,925 for the year ended December 31, 2021 are reported in income from equity method investments on the consolidated statements of operations and comprehensive income (loss). Terminals and Infrastructure does not include the unrealized mark-to-market loss on derivative instruments of $2,788 for the year ended December 31, 2021 reported in Cost of sales. (2) Ships includes the Company's effective share of revenues, expenses and operating margin attributable to 50% ownership of the Hilli Common Units. The earnings attributable to the investment of $32,368 for the year ended December 31, 2021 are reported in income from equity method investments on the condensed consolidated statements of operations and comprehensive income (loss) (3) Consolidation and Other adjusts for the inclusion of the effective share of revenues, expenses and operating margin attributable to 50% ownership of CELSEPAR and Hilli Common Units in our segment measure and exclusion of the unrealized mark-to-market gain or loss on derivative instruments.

Segment operating margin reconciliation

Year Ended December 31, 2020

(in thousands of $)	Terminals and Infrastructure (1)	Ships (2)	Total Segment	Consolidation and Other (3)	Consolidated
Total revenues	451,650	-	451,650	-	451,650
Cost of sales	278,767	-	278,767	-	278,767
Vessel operating expenses	-	-	-	-	-
Operations and maintenance	47,581	-	47,581	-	47,581
Consolidated Segment Operating Margin	**125,302**	**-**	**125,302**	**-**	**125,302**
Less:					
Selling, general and administrative					120,142
Transaction and integration costs					4,028
Contract termination charges and loss on mitigation sales					124,114
Depreciation and amortization					32,376
Interest expense					65,723
Other expense, net					5,005
Tax benefit					4,817
Loss from extinguishment of debt					33,062
Net loss					**(263,965)**

Segment operating margin reconciliation

Year Ended December 31, 2019

(in thousands of $)	Terminals and Infrastructure [1]	Ships [2]	Total Segment	Consolidation and Other [3]	Consolidated
Total revenues	189,125	-	189,125	-	189,125
Cost of sales	183,359	-	183,359	-	183,359
Vessel operating expenses	-	-	-	-	-
Operations and maintenance	26,899	-	26,899	-	26,899
Consolidated Segment Operating Margin	**(21,133)**	**-**	**(21,133)**	**-**	**(21,133)**
Less:					
Selling, general and administrative					152,922
Contract termination charges and loss on mitigation sales					5,280
Depreciation and amortization					7,940
Interest expense					19,412
Other (income), net					(2,807)
Tax provision					439
Net loss					**(204,319)**

Adjusted EBITDA

(in thousands of U.S. dollars)	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q3 2022 LTM
Total Segment Operating Margin	**$373,150**	**$300,083**	**$327,448**	**$339,330**	**$1,340,011**
Less: Core SG&A	38,033	40,960	42,040	47,290	168,323
Add: Pro rata share Core SG&A from unconsolidated entities	1,110	1,390	1,914	1,293	5,707
Adjusted EBITDA (non-GAAP)	**$334,007**	**$257,733**	**$283,494**	**$290,747**	**$1,165,981**

Adjusted EBITDA

(in thousands of U.S. dollars)	FY'19	FY'20	FY'21
Total Segment Operating Margin	**($21,133)**	**$125,302**	**$746,430**
Less: Core SG&A	94,133	91,980	137,144
Less: Pro rata share of Core SG&A from unconsolidated entities	-	-	4,726
Adjusted EBITDA (non-GAAP)	**($115,266)**	**$33,322**	**$604,560**

Adjusted EBITDA

(in thousands of U.S. dollars)	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q3 2022 LTM
Net income (loss)	**$151,723**	**$241,181**	**($178,431)**	**$56,231**	**$270,704**
Add: Interest expense (net of interest income)	46,567	44,916	47,840	63,588	202,911
Add: Tax (benefit) provision	5,403	(49,681)	(86,539)	9,971	(120,846)
Add: Depreciation and amortization	30,297	34,290	36,356	35,793	136,736
Add: Asset impairment expense	-	-	48,109	-	48,109
Add: SG&A items excluded from Core SG&A	36,894	7,081	8,270	20,311	72,556
Add: Transaction and integration costs	2,107	1,901	4,866	5,620	14,494
Add: Other (income) expense, net	(3,692)	(19,725)	(22,102)	10,214	(35,305)
Add: Changes in fair value of non-hedge derivative instruments and contingent consideration	472	(2,492)	2,247	(6,868)	(6,641)
Add: Loss on extinguishment of debt, net	10,975	-	-	14,997	25,972
Add: Pro rata share of Adjusted EBITDA from unconsolidated entities	44,746	50,497	49,951	49,156	194,350
Less: (Income) loss from equity method investments	8,515	(50,235)	372,927	31,734	362,941
Adjusted EBITDA (non-GAAP)	**$334,007**	**$257,733**	**$283,494**	**$290,747**	**$1,165,981**

Adjusted EBITDA

(in thousands of U.S. dollars)	FY'19	FY'20	FY'21
Net (loss) income	**($204,319)**	**($263,965)**	**$92,711**
Add: Transaction and integration costs	-	4,028	44,671
Add: Contract termination charges and loss on mitigation sales	5,280	124,114	-
Add: Depreciation and amortization	7,940	32,376	98,377
Add: Interest expense (net of interest income)	19,412	65,723	154,324
Add: Other (income) expense, net	(2,807)	5,005	(17,150)
Add: Loss on extinguishment of debt, net	-	33,062	10,975
Add: Changes in fair value of non-hedge derivative instruments and contingent consideration	-	-	2,788
Add: Tax provision	439	4,817	12,461
Add: SG&A add-backs	58,789	28,162	62,737
Add: Pro rata share of Adjusted EBITDA from unconsolidated entities	-	-	157,109
Less: (Income) loss from equity method investments	-	-	(14,443
Adjusted EBITDA (non-GAAP)	**($115,266)**	**$33,322**	**$604,560**

Adjusted Net Income and Adjusted Earnings per Share

(in thousands of U.S. dollars)	Q3 2021	Q3 2022
Net (loss) income attributable to stockholders	(9,806)	61,848
Non-cash impairment charges	-	23,760
Adjusted net (loss) income	**(9,806)**	**85,608**
Weighted-average shares outstanding – diluted (QTD)	207,497,013	209,800,427
Adjusted earnings per share	**($0.05)**	**$0.41**

Disclaimers

IN GENERAL. This disclaimer applies to this document and the verbal or written comments of any person presenting it. This document, taken together with any such verbal or written comments, is referred to herein as the "Presentation."

FORWARD-LOOKING STATEMENTS: All statements contained in this Presentation other than historical information are forward-looking statements that involve known and unknown risks and relate to future events, our future performance or our projected results. You can identify these forward-looking statements by the use of forward-looking words such as "expects," "may," "will," "predicts," "intends," "plans," "estimates," "anticipates," or the negative version of these terms or other comparable words. Forward looking statements include but are not limited to: illustrative financial metrics and other similar metrics, including goals, expected financial growth, margins, portfolio optimization, and expectations for returns to shareholders, among others; the successful development, construction, completion, operation and/or deployment of facilities, including our FLNG projects, on time, within budget and within the expected specifications, capacity and design; expectations on volume production and growth, sales and reserves of LNG; expected sources and uses of liquidity and self-generated cash flows; changes to our dividend policy; expectations related to future LNG and energy industries, including demand, pricing and drivers, as well as the development, construction and operation of new facilities; ability to support European energy security supply issues; the anticipated benefits and efficiencies to be derived from the design of Fast LNG technology and location of our projects, including reductions in permitting and development timelines, cost-efficiency, scalability, and the use of existing infrastructure, such as pipelines; the execution of final definitive documents and satisfaction of conditions precedent with respect to agreements; our ability to respond to natural gas demand and leverage our facilities; successful positioning of our hydrogen business and expectations related to the hydrogen industry in the U.S. and globally; expectations related to the impact and implementation of the IRA; expectations related our credit rating; our ability to support our strategic plans through redeployment of volumes and conversion of our downstream business to long-term contracts to achieve more stable pricing and margins; receipt of permits required for our development and operational activities on time; capitalization and funding of our projects; future strategic plans; ability to maintain our expected development timelines; the timing and ability of our projects to add to the global supply capacity; expectations on valuation of our assets; and all the information in the Appendices. These forward-looking statements are necessarily estimates based upon current information and involve a number of risks, uncertainties and other factors, many of which are outside of the Company's control. Actual results or events may differ materially from the results anticipated in these forward-looking statements. Specific factors that could cause actual results to differ from those in the forward-looking statements include, but are not limited to: unknown and unforeseen risks associated with the development of new technologies such as the Fast LNG technology, including failure to meet design and engineering specifications, incompatibility of systems, delays and schedule changes, high costs and expenses, regulatory and legal challenges, instability or clarity of application of laws, and rules and regulations to the technology, among others; risks related to the development, construction, completion or commissioning schedule for the facilities; risks related to the operation and maintenance of our facilities and assets; failure of our third-party contractors, equipment manufacturers, suppliers and operators to perform their obligations for the development, construction and operation of our projects, vessels and assets; our ability to implement our business strategy; cyclical or other changes in the demand for and price of LNG and natural gas; competition in the energy industry; the gas reserves offshore in the expected locations may not be as extensive as we expect; risks related to the approval and execution of definitive documentation; the risk that the proposed transactions may not be completed in a timely manner or at all; inability to realize the anticipated benefits from the technology, including the cost and time savings anticipated; the receipt of permits, approvals and authorizations from governmental and regulatory agencies on a timely basis or at all; new or changes to existing governmental policies, laws, rules or regulations, or the administration thereof; failure to maintain sufficient working capital and to generate revenues, which could adversely affect our ability to fund our projects; adverse regional, national, or international economic conditions, adverse capital market conditions and adverse political developments; and the impact of public health crises, such as pandemics (including coronavirus (COVID-19)) and epidemics and any related company or government policies and actions to protect the health and safety of individuals or government policies or actions to maintain the functioning of national or global economies and markets. These factors are not necessarily all of the important factors that could cause actual results to differ materially from those expressed in any of NFE's forward-looking statements. Other known or unpredictable factors could also have material adverse effects on future results. Any forward-looking statement speaks only as of the date on which it is made, and we undertake no duty to update or revise these forward-looking statements, even though our situation may change in the future. New factors emerge from time to time, and it is not possible for NFE to predict all such factors. When considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements included in New Fortress Energy Inc.'s annual and quarterly reports filed with the Securities and Exchange Commission, which could cause its actual results to differ materially from those contained in any forward-looking statement.

PAST PERFORMANCE. Our operating history is limited and our past performance is not a reliable indicator of future results and should not be relied upon for any reason.

ILLUSTRATIVE ECONOMICS. Illustrative economics are hypothetical values based on specified assumptions that are aspirational in nature rather than management's view of projected results. Actual results could differ materially and the hypothetical assumptions on which this illustrative data is based are subject to numerous risks and uncertainties.

Endnotes

1. “Illustrative Adjusted EBITDA Goal” is based on the "Illustrative Total Segment Operating Margin Goal" less illustrative Core SGA assumed to be at $180mm in 2022 and $192mm for all periods 2023 onward including the pro rata share of Core SG&A from unconsolidated entities. “Illustrative Total Segment Operating Margin Goal,” or “Illustrative Future Goal” means our goal for Total Segment Operating Margin under certain illustrative conditions. Please refer to this explanation for all uses of this term. This goal reflects the volumes of LNG that it is our goal to sell under binding contracts multiplied by the average price per unit at which we expect to price LNG deliveries, including both fuel sales and capacity charges or other fixed fees, less the cost per unit at which we expect to purchase or produce and deliver such LNG or natural gas, including the cost to (i) purchase natural gas, liquefy it, and transport it to one of our terminals or purchase LNG in strip cargos or on the spot market, (ii) transfer the LNG into an appropriate ship and transport it to our terminals or facilities, (iii) deliver the LNG, regasify it to natural gas and deliver it to our customers or our power plants and (iv) maintain and operate our terminals, facilities and power plants. For vessels chartered to third parties, this illustration reflects the revenue from ships chartered to third parties, capacity and tolling arrangements, and other fixed fees, less the cost to operate and maintain each ship, in each case based on contracted amounts for ship charters, capacity and tolling fees, and industry standard costs for operation and maintenance. There can be no assurance that the costs of purchasing or producing LNG, transporting the LNG and maintaining and operating our terminals and facilities will result in the Illustrative Total Segment Operating Margin Goal reflected. For the purpose of this presentation, we have assumed an average Total Segment Operating Margin between $10.37 and $22.13 per MMBtu for all downstream terminal economics, because we assume that (i) we purchase delivered gas at a weighted average of $9.80 in Q4-22, $11.16 in 2022, and $9.93 in 2023, (ii) our volumes increase over time, and (iii) we will have costs related to shipping, logistics and regasification similar to our current operations because the liquefaction facility and related infrastructure and supply chain to deliver LNG from Pennsylvania or Fast LNG (“FLNG”) does not exist, and those costs will be distributed over the larger volumes. For Hygo + Suape assets we assume an average delivered cost of gas of $9.76 in 2022, and $9.90 in 2023 based on industry averages in the region and the existing LNG contract at Sergipe. Hygo + Sergipe incremental assets include every terminal and power plant other than Sergipe, and we assume all are Operational and earning revenue through fuel sales and capacity charges or other fixed fees. This illustration reflects our effective share of operating margin from Sergipe Power Plant. For Vessels chartered to third parties, this illustration reflects the revenue from ships chartered to third parties, capacity and tolling arrangements, and other fixed fees, less the cost to operate and maintain each ship, in each case based on contracted amounts for ship charters, capacity and tolling fees, and industry standard costs for operation and maintenance. We assume an average Total Segment Operating Margin of up to $211k per day per vessel and our effective share of revenue and operating expense related to the existing tolling agreement for the Hilli FLNG going forward. For Fast LNG, this illustration reflects the difference between the delivered cost of open LNG and the delivered cost of open market LNG less Fast LNG production cost. Management is currently in multiple discussions with counterparties to supply feedstock gas at pricing between $4.85 per MMBtu to $7.02 per MMBtu, multiplied by the volumes for Fast LNG installation of 1.4 MTPA each per year. These costs do not include expenses and income that are required by GAAP to be recorded on our financial statements, including the return of or return on capital expenditures for the relevant project, and selling, general and administrative costs. Our current cost of natural gas per MMBtu are higher than the costs we would need to achieve Illustrative Total Segment Operating Margin Goal, and the primary drivers for reducing these costs are the reduced costs of purchasing gas and the increased sales volumes, which result in lower fixed costs being spread over a larger number of MMBtus sold. References to volumes, percentages of such volumes and the Illustrative Total Segment Operating Margin Goal related to such volumes (i) are not based on the Company’s historical operating results, which are limited, and (ii) do not purport to be an actual representation of our future economics. We cannot assure you if or when we will enter into contracts for sales of additional LNG, the price at which we will be able to sell such LNG, or our costs to produce and sell such LNG. Actual results could differ materially from the illustration and there can be no assurance we will achieve our goal.

Endnotes

2. "Adjusted EBITDA" is not a measurement of financial performance under GAAP and should not be considered in isolation or as an alternative to income/(loss) from operations, net income/(loss), cash flow from operating activities or any other measure of performance or liquidity derived in accordance with GAAP. We believe this non-GAAP measure, as we have defined it, offers a useful supplemental view of the overall operation of our business in evaluating the effectiveness of our ongoing operating performance in a manner that is consistent with metrics used for management's evaluation of the Company's overall performance and to compensate employees. We believe that Adjusted EBITDA is widely used by investors to measure a company's operating performance without regard to items such as interest expense, taxes, depreciation, and amortization which vary substantially from company to company depending on capital structure, the method by which assets were acquired and depreciation policies. Further, we exclude certain items from our SG&A not otherwise indicative of ongoing operating performance. We calculate Adjusted EBITDA as net loss, plus transaction and integration costs, contract termination charges and loss on mitigations sales, depreciation and amortization, interest expense (net of interest income), other expense (income), net, loss on extinguishment of debt, changes in fair value of non-hedge derivative instruments and contingent consideration, tax expense, and adjusting for certain items from our SG&A not otherwise indicative of ongoing operating performance, including non-cash share-based compensation and severance expense, non-capitalizable development expenses, cost to pursue new business opportunities and expenses associated with changes to our corporate structure, plus our pro rata share of Adjusted EBITDA from unconsolidated entities, less the impact of equity in earnings (losses) of unconsolidated entities. Adjusted EBITDA is mathematically equivalent to our Total Segment Operating Margin, as reported in the segment disclosures within our financial statements, minus Core SG&A, including our pro rata share of such expenses of unconsolidated entities. Core SG&A is defined as total SG&A adjusted for non-cash share-based compensation and severance expense, non-capitalizable development expenses, cost to pursue new business opportunities and expenses associated with changes to our corporate structure. Core SG&A excludes certain items from our SG&A not otherwise indicative of ongoing operating performance. We calculate Adjusted EBITDA as net loss, plus transaction and integration costs, contract termination charges and loss on mitigations sales, depreciation and amortization, interest expense (net of interest income), other expense (income), net, loss on extinguishment of debt, changes in fair value of non-hedge derivative instruments and contingent consideration, tax expense, and adjusting for certain items from our SG&A not otherwise indicative of ongoing operating performance, including non-cash share-based compensation and severance expense, non-capitalizable development expenses, cost to pursue new business opportunities and expenses associated with changes to our corporate structure, plus our pro rata share of Adjusted EBITDA from unconsolidated entities, less the impact of equity in earnings (losses) of unconsolidated entities. Adjusted EBITDA is mathematically equivalent to our Total Segment Operating Margin, as reported in the segment disclosures within our financial statements, minus Core SG&A, including our pro rata share of such expenses of unconsolidated entities. Core SG&A is defined as total SG&A adjusted for non-cash share-based compensation and severance expense, non-capitalizable development expenses, cost to pursue new business opportunities and expenses associated with changes to our corporate structure. Core SG&A excludes certain items from our SG&A not otherwise indicative of ongoing operating performance. The principal limitation of this non-GAAP measure is that it excludes significant expenses and income that are required by GAAP to be recorded in our financial statements. Investors are encouraged to review the related GAAP financial measures and the reconciliation of the non-GAAP financial measure to our GAAP net income/(loss), and not to rely on any single financial measure to evaluate our business. Adjusted EBITDA does not have a standardized meaning, and different companies may use different Adjusted EBITDA definitions. Therefore, Adjusted EBITDA may not be necessarily comparable to similarly titled measures reported by other companies. Moreover, our definition of Adjusted EBITDA may not necessarily be the same as those we use for purposes of establishing covenant compliance under our financing agreements or for other purposes. Adjusted EBITDA should not be construed as alternatives to net income (loss) and diluted earnings (loss) per share attributable to New Fortress Energy, which are determined in accordance with GAAP.

Endnotes

3. "Total Segment Operating Margin" is the total of our Terminals and Infrastructure Segment Operating Margin and Ships Segment Operating Margin. Terminals and Infrastructure Segment Operating Margin includes our effective share of revenue, expenses and operating margin attributable to our 50% ownership of Centrais Elétricas de Sergipe Participações S.A. ("CELSEPAR"). Ships Segment Operating Margin includes our effective share of revenue, expenses and operating margin attributable to our ownership of 50% of the common units of Hilli LLC. Hilli LLC owns Golar Hilli Corporation ("Hilli Corp"), the disponent owner of the Hilli. Total Segment Operating Margin is a Non-GAAP Financial Measure.

4. "Online", "Operational", "Operating", "Completion", "Completed", "Deployment" or similar statuses (either capitalized or lower case) with respect to a particular project means we expect gas to be made available within sixty (60) days, gas has been made available to the relevant project, or that the relevant project is in full commercial operations. Where gas is going to be made available or has been made available but full commercial operations have not yet begun, full commercial operations will occur later than, and may occur substantially later than, our reported Operational, Completion or Deployment date, and we may not generate any revenue until full commercial operations has begun. We cannot assure you if or when such projects will reach full commercial operations. Actual results could differ materially from the illustrations reflected in this presentation and there can be no assurance we will achieve our goals. Our ability to export liquefied natural gas depends on our ability to obtain export and other permits from the United States, Mexican and other governmental and regulatory agencies , which we have not yet obtained. No assurance can be given that we will receive required permits, approvals and authorizations from governmental and regulatory agencies in connection with the exportation of liquefied natural gas on a timely basis or at all.

5. Represents historic values for the first three quarters of 2022 and illustrative values for the fourth quarter of 2022. Illustrative values are based on specified assumptions. Actual results could differ materially and the assumptions on which this illustrative example is based are subject to numerous risks and uncertainties.

6. "Cash on Hand" means expectations regarding the sum of cash and cash equivalents and restricted cash as of the periods indicated, including committed and unused capacity in our financings and expected proceeds from recent transactions. These values are based on specified assumptions that may not be based on generally accepted accounting principles and are not made by reference to our historical financial statements.

7. "Operating cash flows" refers to illustrative metrics related to Total Segment Operating Margin, less Core SG&A, debt interest payments, and taxes. Refer to note 3 herein for additional information. These values are based on specified assumptions that may not be based on generally accepted accounting principles and are not made by reference to our historical financial statements.

8. Represents management's expectations regarding the funding of the committed expenditures reflected and the estimated expenditures. The estimated expenditures, including those related to project costs, are not based on generally accepted accounting principles and should not be relied upon for any reason. There is no guarantee that we will reach our goals for funding the estimated expenditures and actual results may differ from our expectations.

9. Any determination regarding our dividend policy is determined by our board of directors. We cannot predict what, if any, changes the board of directors may determine regarding our dividend policy.

10. "Under Construction", " "Development," "In Development" or similar statuses means that we have taken steps and invested money to develop a facility, including execution of agreements for the development of the project (subject, in certain cases, to satisfaction of conditions precedent), procuring land rights and entitlements, negotiating or signing construction contracts, and undertaking active engineering, procurement and construction work. Our development projects are in various phases of progress, and there can be no assurance that we will continue progress on each development as we expect or that each development will be Completed or enter full commercial operations. There can be no assurance that we will be able to enter into the contracts required for the development of these facilities on commercially favorable terms or at all. If we are unable to enter into favorable contracts or to obtain the necessary regulatory and land use approvals on favorable terms, we may not be able to construct and operate these assets as expected, or at all. Additionally, the construction of facilities is inherently subject to the risks of cost overruns and delays, and these risks of delay are exacerbated by the COVID-19 pandemic. If we are unable to construct, commission and operate all of our facilities as expected, or, when and if constructed, they do not accomplish our goals, or if we experience delays or cost overruns in construction, our business, operating results, cash flows and liquidity could be materially and adversely affected.

Endnotes

11. Reserved.
12. Refers to the concurrent applications filed by an affiliate of NFE with the U.S. Maritime Administration (“MARAD”), the U.S. Coast Guard and U.S. Department of Energy to request all necessary permits and regulatory approvals to site, construct and operate a new offshore LNG liquefaction terminal off the coast of Louisiana with a capacity of exporting approximately 145 billion cubic feet of natural gas per year, equivalent to approximately 2.8 MTPA of LNG. n August 16, 2022, the U.S. Maritime Administration ("MARAD") announced it had paused the statutory 356-day application review timeline of our FLNG project off the coast of Louisiana pending receipt of additional information. MARAD has continued to review the application and prepare the draft environmental impact statement for the project while the timeline is paused. On October 27, MARAD issued an information request, and on October 28, 2022, MARAD restarted the timeline. No assurance can be given that we will be able to obtain approval of this application and receive the required permits, approvals and authorizations from governmental and regulatory agencies related to our project on a timely basis or at all.
13. Refers to the binding short-form agreements with Comisión Federal de Electricidad (“CFE”) related to the (i) expansion and extension of NFE’s supply of natural gas to multiple CFE power generation facilities in Baja California Sur, (ii) sale of NFE’s 135 MW La Paz power plant to CFE, and (iii) creation of a new LNG hub off the coast of Altamira, Tamaulipas, with CFE supplying the requisite feedgas to multiple NFE FLNG units using CFE’s existing pipeline capacity. These transactions are subject to customary terms and conditions and execution of final long-form binding definitive agreements. We cannot assure you if or when we will enter into long-form definitive agreements related to such projects or the terms of any such agreements. Furthermore, upon execution of long-form definitive agreements, we cannot assure you if or when conditions to such agreements will be satisfied, or if we will obtain the required approvals for the transactions set forth in such agreement.
14. Refers to discussions with Petróleos Mexicanos (“Pemex”) to form a long-term strategic partnership to develop the Lakach deepwater natural gas field for Pemex to supply natural gas to Mexico's onshore domestic market and for NFE to produce LNG for export to global markets. If the parties form a partnership, NFE expects to invest in the continued development of the Lakach field over a two-year period by completing seven offshore wells and to deploy a 1.4 MTPA Fast LNG unit to liquefy the majority of the produced natural gas. Remaining natural gas and associated condensate volumes are expected to be utilized by Pemex in Mexico's onshore domestic market. These transactions are subject to customary terms and conditions and execution of final binding agreements. We cannot assure you if or when we will enter into final binding definitive agreements related to such contracts or the terms of any such contracts.
15. “Mechanical Completion” or similar statuses with respect to a particular project means we have completed construction and certain subsystems are ready to be handed over to the commissioning team. There may be several mechanical completion milestones defined for the various subsystems of a project. Therefore, no assurance can be given that we will be able to complete a project and begin operations even if a project has reached mechanical completion.
16. This slide is an illustrative example of an integrated gas-to-power business model for a new-build, single-cycle power plant, assuming FLNG supply volumes at a Henry Hub index plus operating costs of an FLNG unit. These are hypothetical values based on specified assumptions. Actual results could differ materially and the hypothetical assumptions on which this illustrative example is based are subject to numerous risks and uncertainties.
17. Represents purchase price under a power purchase agreement, representing a dual component of electricity price of $0.125 and a capacity price of $0.250, with a total aggregate purchase price of $0.150.
18. Represents a gas sales price assuming a 9,000 BTU/kWh heat rate for a new-build single-cycle power plant, consisting of the total power price times the heat rate.
19. Represents the cost of obtaining FLNG, assuming $4/mmBTU Henry Hub pricing plus operating costs of an FLNG unit.
20. Represents the illustrative margin to an integrated gas-to-power business model.

Endnotes

21. Represents LNG volumes we expect to derive from our Fast LNG projects currently under development, assuming completion and operation of such projects in line with current design and engineering specifications, expected timelines and capacity levels. There can be no assurance that we will be able to complete our Fast LNG projects on time and in line with specifications required to produce such volumes. In addition, there can be no assurance that we will be able to operate the Fast LNG projects in line with our expectations.

22. The Inflation Reduction Act was signed into law on August 16, 2022 (Public Law 117-169). The U.S. Department of the Treasury and the Internal Revenue Service (IRS) are charged with promulgating the climate and clean energy tax incentives included in the legislation. These implementing regulations have not yet been issued. Furthermore, the IRA is subject to decision, administration and implementation by various governmental agencies and bodies. There is no guarantee that such new implementing regulations or their interpretation, administration or implementation will be favorable to us or our business. In addition, new regulation can be subject to legal challenges in courts, which could lead to its suspension and prevent their implementation.

23. Refers to the non-binding Memorandum of Understanding executed with Entergy Texas ("Entergy") to collaborate on the development of renewable energy and hydrogen infrastructure in South Texas. These transactions are subject to customary terms and conditions and execution of final binding agreements. We cannot assure you if or when we will enter into final binding definitive agreements related to such contracts or the terms of any such contracts.

24. "Adjusted EPS" and "Adjusted net income" are not measurements of financial performance under GAAP and should not be considered in isolation or as an alternative to any measure of performance or liquidity derived in accordance with GAAP. We calculate Adjusted EPS as Adjusted net income divided by the weighted average shares outstanding on a fully diluted basis for the period indicated. We calculate Adjusted net income as net income (loss) attributable to stockholders, plus non-cash impairment charges. We believe these non-GAAP measures, as we have defined them, offer a useful supplemental view of the overall evaluation of the Company in a manner that is consistent with metrics used for management's evaluation of the Company's overall performance. None of Adjusted EPS or Adjusted net income have a standardized meaning, and different companies may use different definitions. Therefore, these terms may not be necessarily comparable to similarly titled measures reported by other companies. .

25. Refers to the sale by NFE and Ebrasil Energia Ltda. and its shareholders ("Ebrasil") to Eneva S.A. ("Eneva") of 100% of the equity interests of the Porto de Sergipe Power Plant, including 100% of the shares of Centrais Elétricas de Sergipe Participações S.A. ("CELSEPAR"), which owns 100% of the equity interests of the Sergipe Power Plant, and Centrais Elétricas Barra dos Coqueiros S.A. ("CEBARRA"), which owns 1.7 GW of expansion rights adjacent to the Sergipe Power Plant. Closing of this transaction occurred on October 3, 2022.

26. Refers to sale of 11 liquefied natural gas ("LNG") infrastructure vessels consisting of Floating Storage and Regasification assets, Floating Storage vessels and LNG carriers owned by NFE to a newly formed joint venture named Energos Infrastructure ("Energos"), owned approximately 80% by Apollo-managed funds and 20% by NFE. Closing of this transaction occurred on August 15, 2022.

27. "Run Rate" means the date on which management currently estimates the initial ramp-up of operations on a particular facility will be over, and full commercial operations will be running at a sustainable level. Volumes of LNG and natural gas that we are able to deliver and sell through a particular facility may keep increasing after the Run Rate date due to additional large or small scale customers being added for service by any particular facility, so the Run Rate does not represent the date on which management expects the relevant facility to be operating at its Capacity Volume. Capacity Volume operations of such projects will occur later than, and may occur substantially later than, Run Rate. We cannot assure you if or when such projects will reach the date Run Rate or full Capacity Volume. Actual results could differ materially from the illustration and there can be no assurance we will achieve our goal.

28. "Reliability" means the percentage of time the facility is operable less planned or unplanned downtime. There can be no assurance that other facilities, future facilities or the same facilities over a different timeframe will achieve similar results and actual results could differ materially from previous results. The results of any particular facility are not representative of the results of facilities as a whole and should not be used as an indicator of future results.

29. For the year 2021 and the first three quarters of 2022, includes LNG volume equivalent to power revenue under the PPAs from the Sergipe Power Plant by CELSE – Centrais Elétricas de Sergipe S.A.