bpx energy

bp

bpx strategy discussion

June 7th, 2021

Executive summary

What's changed at bpx?

Redacted - Commercially Sensitive Material

- **Current plan: $112m FCF in 2022 on $1.42b capital investment, >50% IRR on D&C program (all at current strip)**
  - Recommended plan is FCF positive in every year at May 21 strip prices. Although modest in 2022 – 2023, cash flow ramps significantly thereafter and for a cumulative $3.9bn from 2021 – 2027.
  - 2020 plan to deliver over $600m of FCF on $900m of capital investment at current prices.
  - Variances from plan presented at capital markets day are most material in gas / NGL production and cash flow, but more aligned in crude production.
- **Recap of the recent history:**
  - 2018 - 2019: Announce acquisition and begin integration. Accelerate development in Eagle Ford and begin design of Permian infrastructure. Drill to retain acreage in Permian. In Texas Haynesville, disappointing results due to technical complications.
  - 2020: Installed Grand Slam CDP in Permian and began CDP installation in Eagle Ford Karnes. Stopped D&C programs in April due to Covid price-impacts, causing deterioration of economics due to DUCs (from $2.1bn plan to $1bn) and only lease-drilling. Appraised Austin Chalk Type II in Eagle Ford – moderate results.
  - 2021: $900m Plan focused on maximizing cash flow in recovery from 2020. Very limited infrastructure investment, but restart of programs in Permian and Eagle Ford with focus on lease retention. First wells drilled in Louisiana Haynesville under bpx.
  - 2022+: Fund infrastructure internally to set up 2024+ material cash flow growth. Maintain oil-focus and full utilization of infrastructure with discretionary investment after lease position secured. Grow capital budget from $1.5 in 2022 to $2bn flat thereafter.

Bpx is a premier investment platform

High-return, low-risk projects deliver $3.9bn+ cumulative FCF 2021-2027

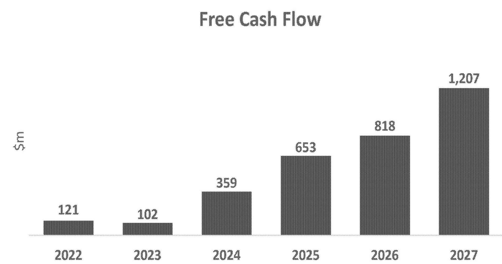
Cash generative:
- FCF positive in every year of business plan (@ May strip prices), while self-funding infrastructure and further shifting to oil-weighted strategy.

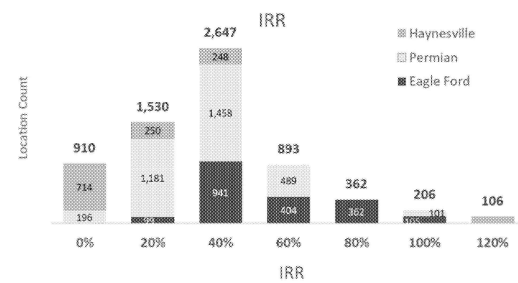
Staying power:
- Over 5,000 locations deliver >40% IRR and >1.4 3-year cash flow efficiency (cumulative 3-year ops cash / capex). Optimizing on cash flow efficiency helps sustain FCF delivery year over year where our peers have struggled

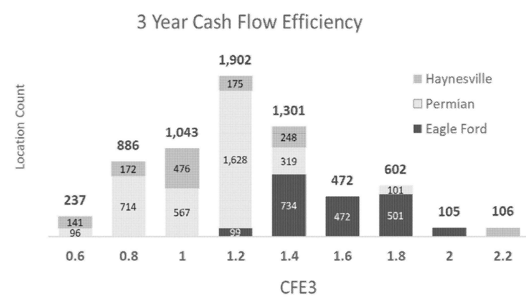
Continuous improvement:
- Bpx team has improved every asset we have acquired, and we continue to see significant gains in rates and EURs due to our proprietary RTAN method and we are top quartile in Gross Revenue per foot of lateral in Permian (Delaware), Eagle Ford and Texas Haynesville areas

Driving consistency:
- Further linking short term and long-term planning processes, standing up WTA and Standards are showing improvement in execution consistency and cost efficiency leading to safer more reliable investment program

Committed to our future:
- Detailed carbon emissions reductions strategy built into investment approach with 82% of our targeted reduction by 2025 underpinned and included with visibility to more



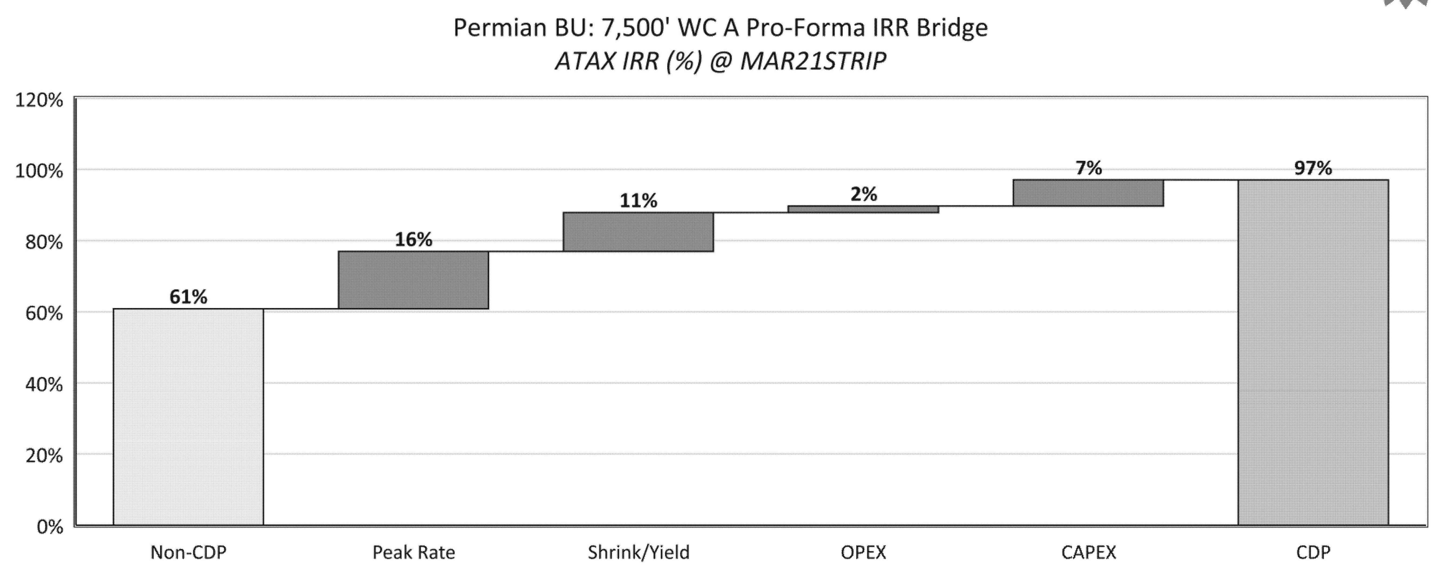




1. *CFE3 calculated as 3 years of net OCF divided by net capital investment*
2. *FCF shown at May21Strip Pricing; IRR and CFE3 at Mar21Strip*

The case for infrastructure: operated CDP advantages

Flowing wells to CDPs increases well IRR by >30% and reduces flaring by 80%



- Flowing wells to CDPs improves well level economics from 61% IRR to 97% IRR @MAR21STRIP
  - **Peak Rate** – flowing to a CDP reduces line pressure resulting in 30% higher peak rates
  - **Shrink/Yield** – CDPs reduce flaring by 80%, reduces on-lease fuel consumption, and results in a richer gas and higher NGL yields
  - **OPEX** – Well run-time by >42%; Base well tie-ins uplifted 19%; CDPs reduce on-site compression costs and gathering and disposal fees vs 3rd party options
  - **CAPEX** – CDPs reduce on-site facilities cost by average of $0.4m per well
- CDPs reduce GHG from field electrification: 80% of Permian electrified by end of 2021

D-cost continues to improve

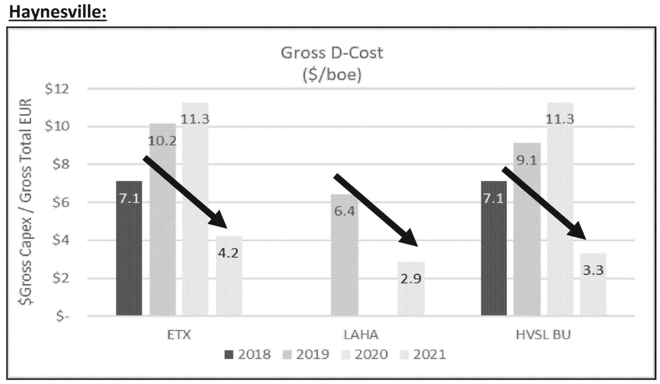
Lower well costs and enhanced completions drive D-Cost improvements to below acquisition case

Eagle Ford:
- **1% (BH), -87% (HV), -58% (LJV) change from 2018 to 2021**
- **BH and HV** steadily lowering well costs post acquisition; HV steadily improving EURs.
- 2021 HV narrows the gap to LJV
- **LJV** shorter lateral lengths in 2018-20 drive lower well costs. 2021 lateral lengths are 23% longer vs. 2020 and narrows the gap to BPX. Enhanced frac design drives higher EURs starting in 2020.

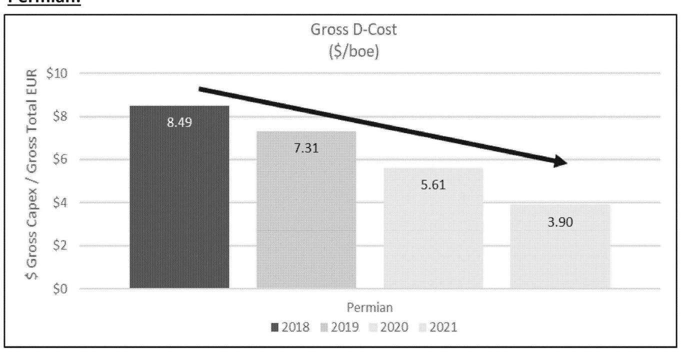
Haynesville:
- ***46% decrease from 2018 to 2021*** ($7.10/boe to $3.30/boe) driven by program shifting from SOHA to LAHA and drilling longer laterals (41% increase in lateral lengths; 7,118' historical vs. 10,050' 2021)
- Small well set in 2020 with operational challenges show higher D Cost due to cost overruns and lower EUR

Permian:
- **54% decrease from 2018 to 2021** ($8.49/boe to $3.90/boe) driven by lower well costs ***(-24% in $/ft since 2018)***, drilling longer laterals (***6,200' in '18, 8,100' in '21***) and drilling more core WCA wells as the program shifts from obligation activity
- SKO B208H best to-date at $2.62/boe
- ***CDP wells show 30% D-Cost improvement compared to non-CDP wells***

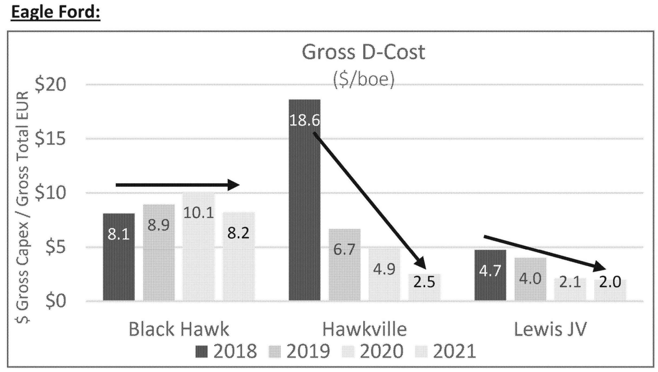
Haynesville:



Permian:



Eagle Ford:



(1) Acquisition Model D-Cost a net well weighted average across entire acquired asset

Project cash generation improving

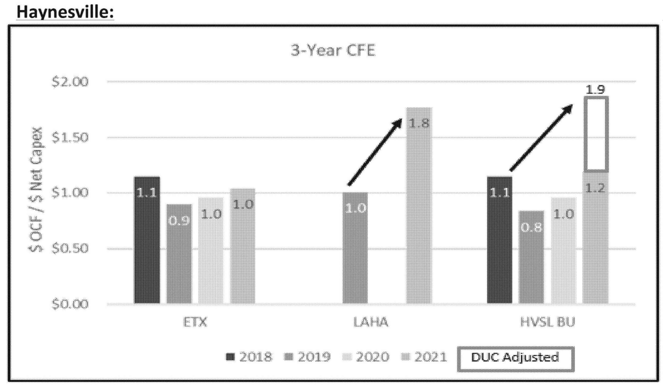
Lower well costs and enhanced completions drive 3 Year CFE improvements YoY

Eagle Ford:
- **+15% (BH), +331% (HV), +190% (LJV) change in 3-yr CFE**
- **BH** 1-yr CFE decrease driven by curtailment for pricing in 1H20 and Karnes underperformance due to stress rotation/ESP downtime.
- Stable or increasing 3 yr CFEs in in **BH** and **HV** driven by lowering well costs and improving EURs, offset by curtailment for pricing and shifting inventory mix in BH.
- **LJV** 2018-20 impacted by multiple 1+ year DUCs

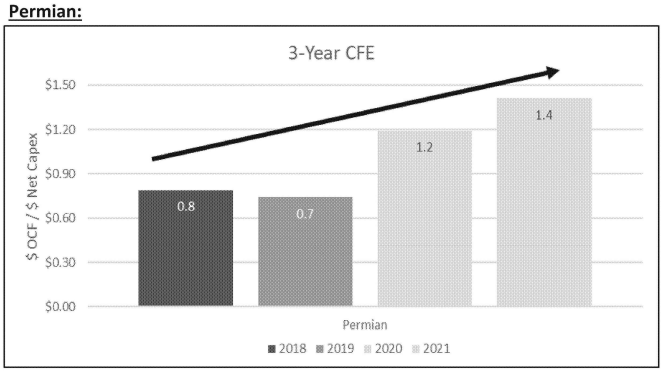
Haynesville:
- Driven by lower well costs ($2,450/ft historically vs. $1,532/ft in 2021), program shift to LAHA and accelerated production (up to 50% with casing flow) being offset by 2020 DUCs.
- **DUC adjusted, *33% improvement in 1yr and 73% 3yr CFE***

Permian:
- ***78% increase in 3-yr CFE***
- Driven largely by lower well costs and more core WCA wells as the program shifts out of obligation mode

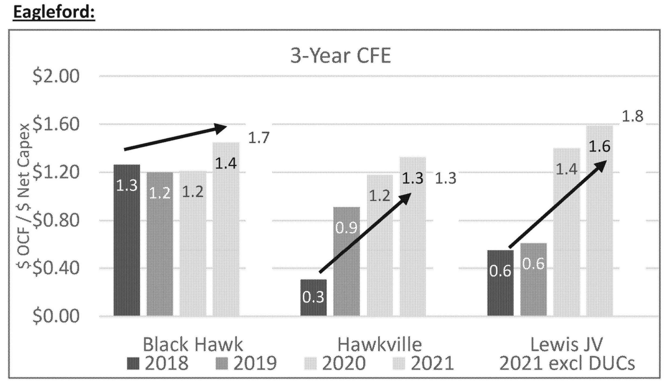
Haynesville:



Permian:



Eagleford:



1. *CFE3 calculated as 3 years of net OCF divided by net capital investment*

Benchmarking takeaways

Focused on safe and efficient development of top-tier resource base

		Permian	Blackhawk	Hawkville	South (Lewis JV)	LaHa	East	bpx
Unless otherwise noted, metric is quartile for the 2017-19 period								
Well Productivity Metrics								
12 Month Oil Cum*	MBbl per 1k ft of LL	1st	1st	1st	4th	NM	NM	
12 Month Oil-Equivalent Cum	MBOE per ft of LL	2nd	1st	2nd	1st	2nd	1st	
12 Month Gross Revenue**	$ per ft of LL	1st	1st	1st	2nd	2nd	1st	
**Blackhawk includes wells RSEG categorizes as DVN*								
*** Assumes BPX planning prices of $45/$19/$2.50 for oil, NGLs and natural gas, respectively and long-term basin differentials*								
Development Cost Metrics								
Well Cost	$ per ft of LL	4th	2nd	3rd / 4th	3rd / 4th	4th	4th	
Well Cost - RSEG	$ per ft of LL	$1,300	$1,026	$1,013	$1,039	$1,757	$1,794	
Peer Average	*$ per ft of LL*	*$1,082*	*$926*	*$687*	*$687*	*$1,426*	*$1,404*	
Operating Cost Metrics*								
Trailing 9 Month Unit Opex**	$ per BOE	$15.7	$13.6	$9.3	$4.7	$8.3	$3.2	$9.2
Peer Average	*$ per BOE*	*$10.8*	*$11.7*	*$11.7*	*$11.7*	*$7.4*	*$7.4*	*$10.8*
Trailing 9 Month Unit Cash Margin	$ per BOE (pre-hedge)	$6.4	$12.8	$5.7	$6.5	($0.3)	$6.8	$5.6
Peer Average	*$ per BOE (pre-hedge)*	*$15.8*	*$13.9*	*$13.9*	*$13.9*	*$6.3*	*$6.3*	*$13.1*
Trailing 9 Month Margin Capture	% of Hydrocarbon Rev	29%	49%	38%	58%	-4%	68%	38%
Peer Average	*% of Hydrocarbon Rev*	*59%*	*54%*	*54%*	*54%*	*46%*	*46%*	*55%*
**bpx excludes divested San Juan and MidCon properties. Permian includes Midstream. LaHa unadjusted for firm transportation expenses.*								
*** Opex includes LOE, GP&T, Production & Ad Valorem Taxes. LaHa includes $3.9/BOE unutilized firm transportation expense*								
Economic Metrics*								
D-Cost	$ per BOE	$5.6	$10.1	$4.9	$2.1	N/A	$11.3	
Peer Average	*$ per BOE*	*$12.2*	*$15.9*	*$21.4*	*$21.4*	*$7.2*	*$6.3*	
1 Yr Cash Flow Efficiency	Ops CF / Capex	0.3	0.5	0.6	0.3	N/A	0.4	
Peer Average	*Ops CF / Capex*	*0.4*	*0.5*	*0.3*	*0.3*	*0.3*	*0.3*	

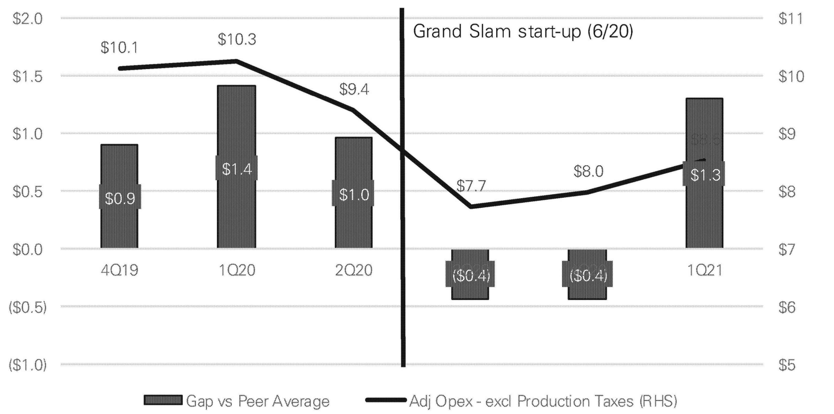
** bpx data based on FY20 wells; peers based on 2019 wells (due to lag in public data availability). Assume facilities costs ranging from $450k-$780k per well.*
Cash Flow Efficiency calculation assumes benchmark oil / NGL / natural gas prices of $42.5 / $17.6 / $3.0, respectively.

Delivering peer leading well economics via premium rock and detailed engineering; rather than excessive focus on costs. Ops organization focused on safe operations and maintaining lowest unit G&A cost of top peers.

Permian operating cost benchmarking

In-field gathering investment narrowing cost gap versus peers

Permian Adj. Opex ($/BOE, including Midstream)



		4Q19	1Q20	2Q20	3Q20	4Q20	1Q21
Adjusted Opex Detail*							
LOE**	$ / BOE	$7.4	$7.0	$6.3	$5.4	$5.8	$5.9
GP&T	$ / BOE	$1.3	$1.3	$1.3	$1.2	$1.2	$1.2
Production Taxes	$ / BOE	$1.5	$1.0	$0.4	$0.7	$0.8	$1.3
G&A - Total	$ / BOE	$1.3	$2.0	$1.2	$0.8	$0.8	$1.2
Other Expense / (Income)	$ / BOE	$0.1	$0.0	$0.7	$0.3	$0.3	$0.2
Total Opex	**$ / BOE**	**$11.6**	**$11.3**	**$9.8**	**$8.4**	**$8.8**	**$9.8**
Total Opex Excl Production Taxes	$ / BOE	$10.1	$10.3	$9.4	$7.7	$8.0	$8.5
Gap to Permian Peers***	$ / BOE	$0.9	$1.4	$1.0	($0.4)	($0.4)	$1.3
For Reference							
Downtime Impact	$ / BOE	$3.8	$5.0	$4.1	$2.1	$2.5	$1.9
Gathering Related (Chemicals / Rentals)	$ / BOE	$2.1	$2.9	$2.1	$1.3	$1.6	$1.5
Flowback Impact	$ / BOE	$0.3	$0.4	$0.5	$0.6	$0.7	$0.5

** Reported figures adjusted for excess (>5%) downtime, excess chemical and compression/generator rental expenses related to poor midstream assets on acquired properties and expensed flowback costs (which are capitalized by some peers)*

***1Q21 LOE excludes $15m ($2.5 per BOE) of Winter Storm Uri-related electricity costs*

****1Q21 Gap vs Peer Average not adjusted for Winter Storm Uri-related electricity charges*

Permian peers include: Callon Petroleum (CPE), Centennial Resource Development (CDEV), Cimarex Energy (XEC), Devon Energy (DVN), Diamondback Energy (FANG), EOG Resources (EOG), Matador Resources (MTDR) and Pioneer Natural Resources (PXD)

- Grand Slam CDP was placed in-service on June 25th and is the first part of a planned, multi-product midstream system in the Delaware (Permian) Basin that allows bpx to develop its resource base in a cost-efficient, environmentally sustainable manner

- Start-up of the in-field gathering assets has contributed to lower levels of methane flaring, lower levels of deferment (downtime) and reduced need for chemicals and rentals expenses related to the lack of prior gathering investment on acquired properties

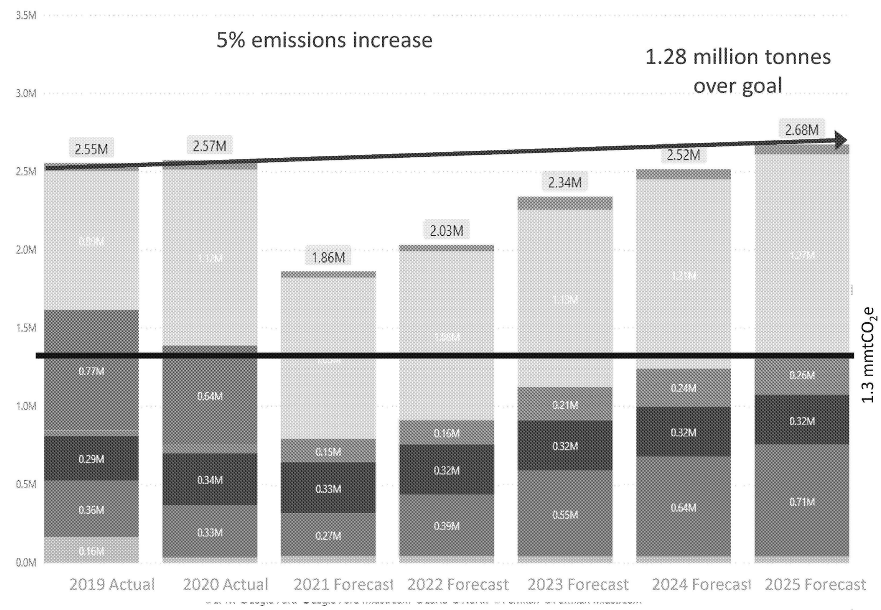
- Volatility in results in 1Q21 due to Texas winter storm and associated costs, expect future quarters to moderate in line with 3Q20 and 4Q20

5-year GHG forecast

Detailed modeling and integrated planning show status quo won't achieve our goals

Business as Usual Forecast

- Business growth without GHG reduction projects
- Nearly 1,000 new wells POL by 2025 each increase GHG
- **Top sources**
  - Flare (750k)
  - Natural gas engines (820k)
  - D&C (440k)
- **Top reduction**
  - Wamsutter divestment (-640k)



Notes:
1. This GHG Forecast is a Draft subject to review and assurance.
2. Final estimates update based on approved investment strategy

50% reduction from 2019 emissions by 2025

Confidential

5-year GHG forecast – funding all mitigation projects in plan

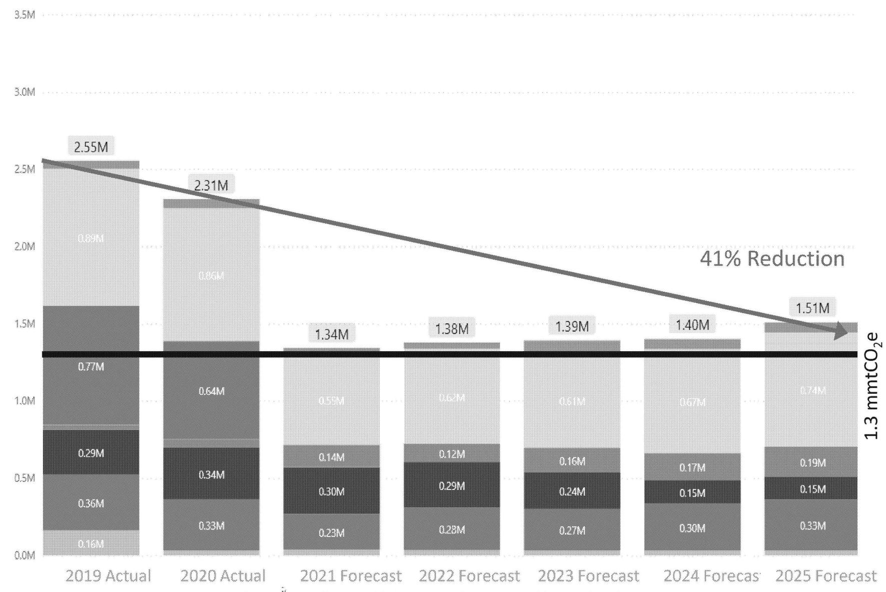
Allocating reduction ideas into the investment strategy underpins 41% of 50% reduction target

Forecast with All Projects
- Most business growth offset by GHG reduction projects
- 690k reduction in flaring

Top sources
- Natural gas engines (400k)
- D&C fuel (400k)
- Fugitives (300k)

Top projects
- Hawkville VRUs (-170k)
- Hawkville blowcases (-150k)
- EF compressor electrifications (-150k)

Technology solutions to close the gap
- Natural gas engine alternatives
- Electrified completions
- Advanced leak detection and repair



AIM 1 Net Zero operations

50% reduction from 2019 emissions by 2025

Notes:
1. This GHG Forecast is a Draft subject to review and assurance.
2. All Projects includes projects that are 'Approved' as well as projects in the Project Hopper
3. Estimate built on April plans from business units and will require update based on approved investment strategy

Long-term financial & operating plan @ May 21 strip

BPX		2020	2021	2022	2023	2024	2025	2026	2027
Production	*mboed*	**373**	**276**	**315**	**354**	**427**	**466**	**474**	**528**
Oil	*mbbld*	72	64	77	94	117	133	135	151
NGL	*mbbld*	59	46	53	58	71	83	89	99
Gas	*mmcfd*	1,405	963	1,073	1,170	1,387	1,450	1,447	1,617
Gross Margin	*$m*	1,809	2,423	2,644	2,985	3,591	3,966	4,049	4,511
Total Cash Costs	*$m*	(1,063)	(922)	(985)	(1,019)	(1,332)	(1,277)	(1,215)	(1,271)
Unit Cash Costs	*$/boe*	*(7.8)*	*(9.2)*	*(8.6)*	*(7.9)*	*(8.5)*	*(7.5)*	*(7.0)*	*(6.6)*
DD&A	*$m*	(1,634)	(1,246)	(1,453)	(1,635)	(1,960)	(2,144)	(2,185)	(2,394)
RCOP	*$m*	(1,133)	168	206	331	299	546	649	846
Working Capital, Decomm & Provisions	*$m*	(245)	(107)	(117)	(20)	85	(36)	(16)	(33)
Ops Cash Flow	*$m*	**501**	**1,414**	**1,542**	**1,946**	**2,344**	**2,653**	**2,818**	**3,207**
Capex	*$m*	(1,003)	(948)	(1,504)	(1,912)	(2,000)	(2,000)	(2,000)	(2,000)
Capex Creditors	*$m*	(282)	48	84	68	15	0	(0)	0
Cash Capex	*$m*	**(1,284)**	**(900)**	**(1,420)**	**(1,844)**	**(1,985)**	**(2,000)**	**(2,000)**	**(2,000)**
Free Cash Flow	*$m*	(783)	514	121	102	359	653	818	1,207
For Reference									
Marker Price									
Oil	*$/bbl*	41.27	53.89	60.77	57.46	55.41	54.32	54.32	54.32
NGL	*$/bbl*	18.28	24.14	23.76	21.62	21.16	20.98	20.98	20.98
Gas	*$/mmcfd*	2.22	2.93	2.77	2.60	2.60	2.62	2.62	2.62
Realization Price									
Oil	*$/bbl*	34.91	50.51	58.93	55.72	53.74	52.73	52.67	52.59
NGL	*$/bbl*	10.60	17.23	16.08	14.63	14.32	14.13	14.10	14.07
Gas	*$/mmcfd*	1.29	2.91	2.64	2.48	2.48	2.48	2.48	2.48

2021 product prices assume GFO2 assumptions, all other periods based on May '21 strip

Ops cash flow profile @ May 21 strip

Ops Cash Flow ($mn)	2020	2021	2022	2023	2024	2025	2026	2027
Permian	118	454	578	614	975	1,412	1,525	1,705
Blackhawk	250	429	427	560	455	386	327	316
Hawkville	92	155	265	298	228	190	222	306
Louisiana Haynesville	(35)	49	91	179	214	263	278	365
Texas Haynesville	187	179	134	71	59	60	58	59
South	81	233	149	152	182	179	195	207
TX Gathering - Permian	30	33	86	97	163	239	269	304
TX Gathering - Eagle Ford Karnes	3	9	0	0	4	6	3	1
Midstream JV	118	98	115	131	112	96	100	118
Resid	(129)	(117)	(186)	(136)	(132)	(141)	(143)	(141)
Divest / Other	31	1						
Total bpx Ops Cash Flow (pre-WC)	746	1,521	1,659	1,966	2,259	2,690	2,834	3,240
Working Capital, Decomm. & Provisions	(245)	(107)	(117)	(20)	85	(36)	(16)	(33)
Total bpx Ops Cash Flow	501	1,414	1,542	1,946	2,344	2,653	2,818	3,207

2021 product prices assume GFO2 assumptions, all other periods based on May '21 strip

Ops Cash Flow ($ per BOE)	2020	2021	2022	2023	2024	2025	2026	2027
Permian	5.7	19.2	20.1	19.5	18.9	19.4	18.9	18.9
Blackhawk	11.7	22.4	22.8	24.8	21.6	21.4	21.6	22.3
Hawkville	4.5	11.4	12.5	12.1	8.4	8.3	10.0	12.0
Louisiana Haynesville	(1.9)	3.5	4.5	6.7	6.5	8.3	9.1	9.6
Texas Haynesville	6.8	10.4	10.0	7.9	7.8	8.3	8.8	9.2
South	7.1	19.0	11.4	10.7	11.3	10.3	11.1	11.2
Total bpx Ops Cash Flow (pre-WC)	6.2	15.2	14.4	15.3	14.4	15.8	16.4	16.8

2021 forecasts assume GFO2 product price assumptions. 2022+ assume 5/11/21 futures strip

Free cash flow profile @ May 21 strip

Free Cash Flow ($mn)	2020	2021	2022	2023	2024	2025	2026	2027
Permian	(108)	245	255	41	83	515	622	863
Blackhawk	(1)	204	82	335	244	198	215	169
Hawkville	48	63	(27)	115	118	56	(67)	(68)
Louisiana Haynesville	(27)	(75)	(74)	(34)	(15)	74	71	22
Texas Haynesville	144	132	134	71	79	71	87	99
South	59	173	84	87	79	71	87	99
TX Gathering - Permian	(224)	(47)	(170)	(437)	(158)	(107)	(16)	278
TX Gathering - Eagle Ford Karnes	(61)	(13)	(23)	(23)	3	5	2	1
Midstream JV	110	86	92	47	77	63	92	40
Resid*	(227)	(195)	(197)	(148)	(250)	(258)	(260)	(264)
Divest / Other	31	1						
Total bpx Free Cash Flow (pre-WC & CC)	(257)	572	155	54	259	690	834	1,240
Working Capital, Decomm. & Provisions	(204)	(107)	(117)	(20)	85	(36)	(16)	(33)
Capex Creditors	(282)	48	84	68	15	0	(0)	0
Total bpx Free Cash Flow - Organic	(742)	514	121	102	359	653	818	1,207
Divestment Proceeds	576	104	0	0	0	0	0	0
Total bpx Free Cash Flow - Reported	(166)	618	121	102	359	653	818	1,207

2021 product prices assume GFO2 assumptions, all other periods based on May '21 strip

**2024+ Resid forecasts includes capitalized overhead. Capitalized overhead absorbed at BU levels over 2020-23.*

Price decks

		2020	2021	2022	2023	2024	2025	2026	2027
May 2021 Strip*									
Oil - WTI	$/Bbl	$41.27	$53.89	$60.77	$57.46	$55.41	$54.32	$54.32	$54.32
NGL - Mont Belvieu	$/Bbl	$18.28	$24.14	$23.76	$21.62	$21.16	$20.98	$20.98	$20.98
Natural Gas - Henry Hub	$/Mcf	$2.22	$2.93	$2.77	$2.60	$2.60	$2.62	$2.62	$2.62
**2021 product prices based on GFO2 assumptions*									
2021 GFO2									
Oil - WTI	$/Bbl	$41.27	$53.89	$49.00	$49.90	$50.90	$52.00	$55.20	$58.70
NGL - Mont Belvieu	$/Bbl	$18.28	$24.14	$20.44	$20.17	$20.72	$21.27	$22.33	$23.45
Natural Gas - Henry Hub	$/Mcf	$2.22	$2.93	$3.10	$3.18	$3.25	$3.31	$3.38	$3.45
March 2021 Strip									
Oil - WTI	$/Bbl	$41.27	$60.88	$56.56	$53.37	$51.61	$50.73	$50.73	$50.73
NGL - Mont Belvieu	$/Bbl	$18.28	$27.38	$23.33	$21.11	$20.82	$21.04	$21.04	$21.04
Natural Gas - Henry Hub	$/Mcf	$2.22	$2.83	$2.69	$2.53	$2.52	$2.52	$2.52	$2.52
2021 GFO1 (bpx level-loaded Plan)									
Oil - WTI	$/Bbl	$41.27	$42.50	$49.00	$49.90	$50.90	$52.00	$55.20	$58.70
NGL - Mont Belvieu	$/Bbl	$18.28	$17.61	$20.44	$20.17	$20.72	$21.27	$22.33	$23.45
Natural Gas - Henry Hub	$/Mcf	$2.22	$3.00	$3.10	$3.18	$3.25	$3.31	$3.38	$3.45
2021 GFOz									
Oil - WTI	$/Bbl	$41.27	$42.50	$49.00	$49.90	$50.90	$52.00	$55.20	$58.70
NGL - Mont Belvieu	$/Bbl	$18.28	$17.61	$20.44	$20.17	$20.72	$21.27	$22.33	$23.45
Natural Gas - Henry Hub	$/Mcf	$2.22	$3.00	$3.10	$3.18	$3.25	$3.31	$3.38	$3.45
2020 GFOz**									
Oil - WTI	$/Bbl	$59.54	$54.33	$56.52	$57.74	$58.98	$60.24	$61.53	$62.84
NGL - Mont Belvieu	$/Bbl	$22.31	$22.89	$23.14	$22.87	$23.23	$23.73	$24.24	$24.75
Natural Gas - Henry Hub	$/Mcf	$2.50	$3.25	$3.31	$3.38	$3.45	$3.51	$3.59	$3.66

*** 2020 WTI initially forecast as $55.00/Bbl, later rebased to $59.54*

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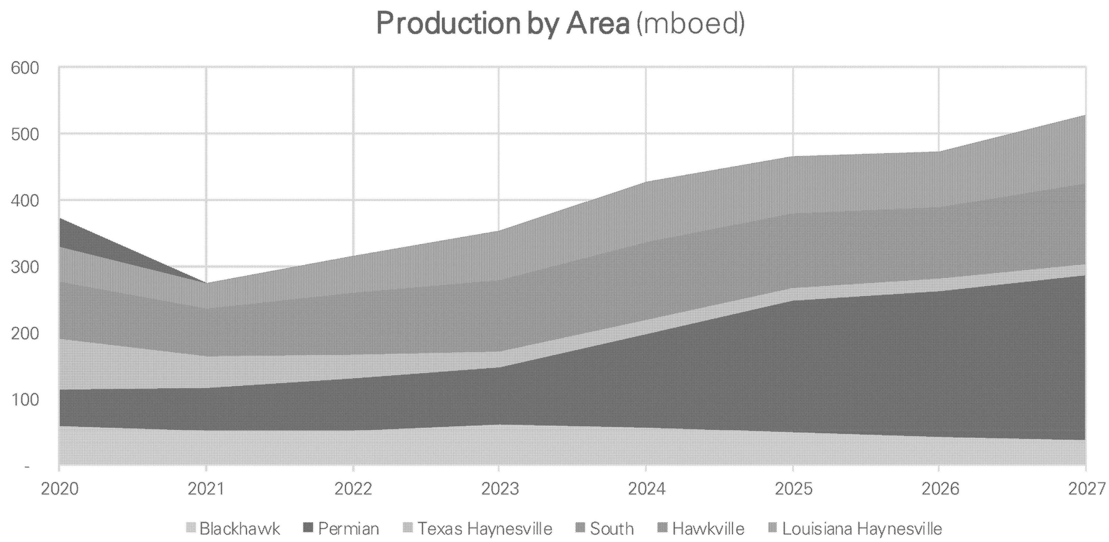
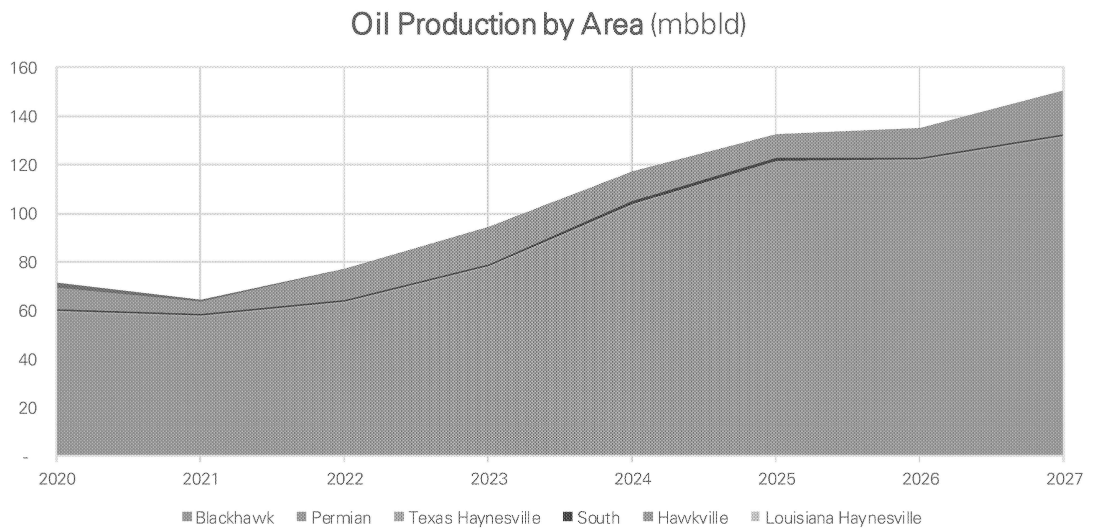
Total production



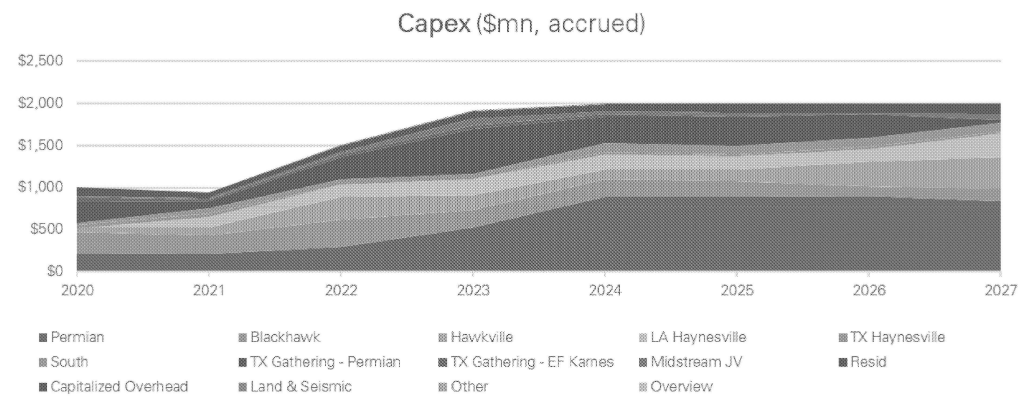
Production (mboepd)	2020	2021	2022	2023	2024	2025	2026	2027
North	44	2	-	-	-	-	-	-
Blackhawk	59	53	51	62	58	49	42	39
Texas Haynesville	75	47	37	25	21	20	18	18
Louisiana Haynesville	51	39	55	73	90	87	83	104
Permian	57	65	79	87	141	199	221	248
Hawkville	56	37	58	68	74	63	61	70
South	31	33	36	39	44	48	48	51
Resid	-	-	-	-	-	-	-	-
Total	373	276	315	353	427	466	474	528

Oil production



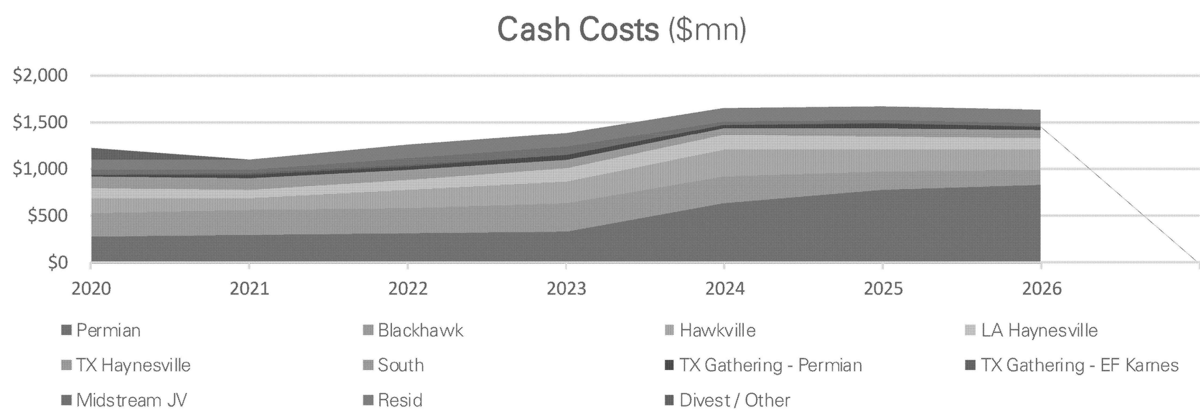
Oil Production (mbbld)	2020	2021	2022	2023	2024	2025	2026	2027
Divest	2	0	-	-	-	-	-	-
Blackhawk	33	29	29	39	34	26	21	20
Texas Haynesville	1	1	1	1	1	0	0	0
Louisiana Haynesville	0	0	-	-	-	-	-	-
Permian	26	29	34	38	70	96	101	112
Hawkville	9	5	12	15	12	10	12	18
South	1	0	1	1	1	1	1	1
Resid	-	-	-	-	-	-	-	-
Total	72	64	77	94	117	133	135	151

Capital allocation



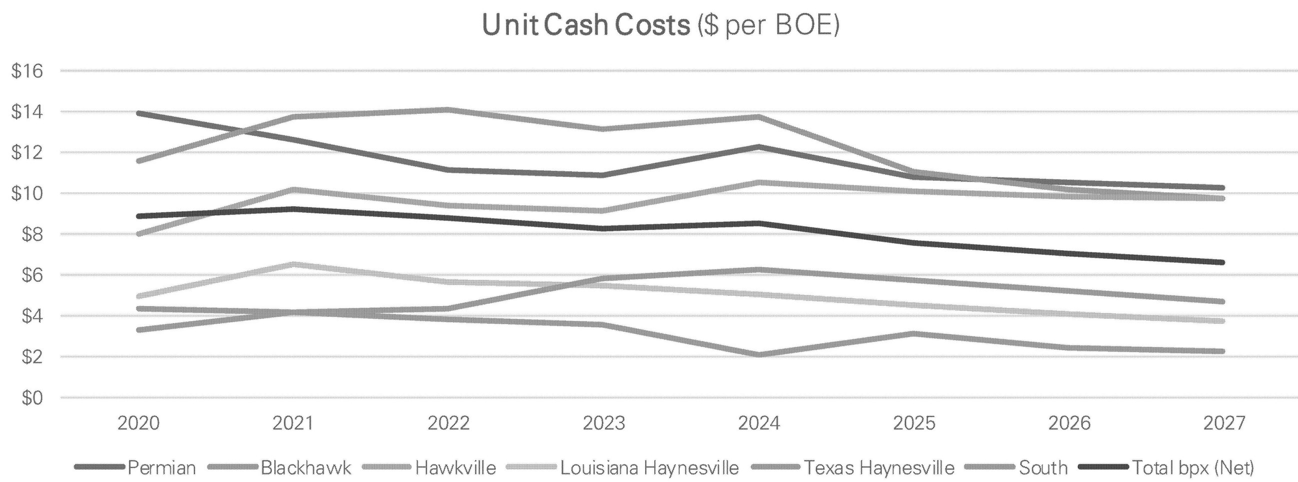
Capex ($mn)	2020	2021	2022	2023	2024	2025	2026	2027
Permian	226	209	298	530	892	896	903	843
Blackhawk	251	225	319	208	211	188	113	147
Hawkville	45	92	270	169	110	134	290	374
Louisiana Haynesville	(8)	124	153	197	184	153	153	278
Texas Haynesville	43	47	0	0	25	25	25	25
South	22	60	60	60	104	108	108	108
Total Upstream	**579**	**758**	**1,101**	**1,165**	**1,526**	**1,503**	**1,590**	**1,774**
TX Gathering - Permian	254	79	257	534	321	345	284	25
TX Gathering - Eagle Ford Karnes	63	22	37	38	24	0	0	0
Midstream JV	8	12	23	84	35	33	8	78
Total Infrastructure / Midstream	**326**	**113**	**317**	**656**	**380**	**378**	**291**	**102**
Resid	(3)	7	7	5	5	19	19	19
Capitalized Overhead	101	71	75	79	83	87	91	96
Land & Seismic			7	7	7	13	9	9
Other					0	0	0	0
Overview	0	0	0	0	0	0	0	0
Total Other	**98**	**77**	**89**	**91**	**95**	**119**	**119**	**124**
Total bpx	1,003	948	1,506	1,912	2,000	2,000	2,000	2,000

Cash costs



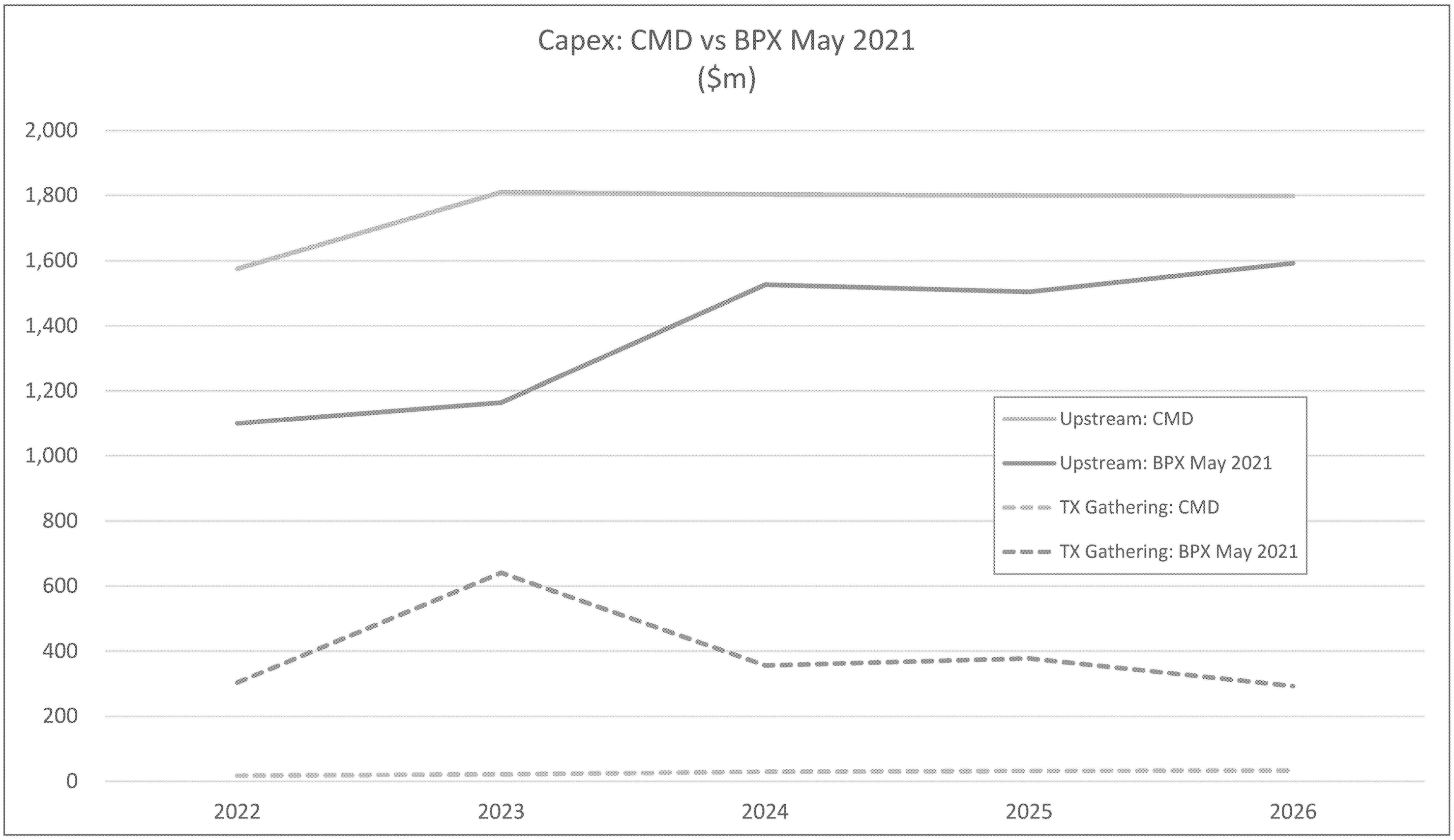
Cash Costs ($mn)	2020	2021	2022	2023	2024	2025	2026	2027
Permian	290	297	318	343	632	785	845	928
Blackhawk	247	263	263	295	289	198	155	138
Hawkville	163	138	198	225	286	230	219	248
Louisiana Haynesville	92	92	113	146	164	143	123	141
Texas Haynesville	90	72	58	53	47	41	34	30
South	50	51	50	50	33	54	42	42
TX Gathering - Permian	14	39	40	48	25	39	43	47
TX Gathering - Eagle Ford Karnes	5	9	0	0	1	2	1	0
Midstream JV	50	45	75	90	35	38	38	39
Resid	117	97	141	141	141	141	141	141
Divest / Other	113	9						
Total bpx (Gross)	1,231	1,112	1,256	1,391	1,652	1,670	1,641	1,755
Intercompany	168	191	250	325	317	390	425	482
Total bpx (Net)	1,063	922	1,006	1,066	1,335	1,279	1,216	1,272

Unit cash cost

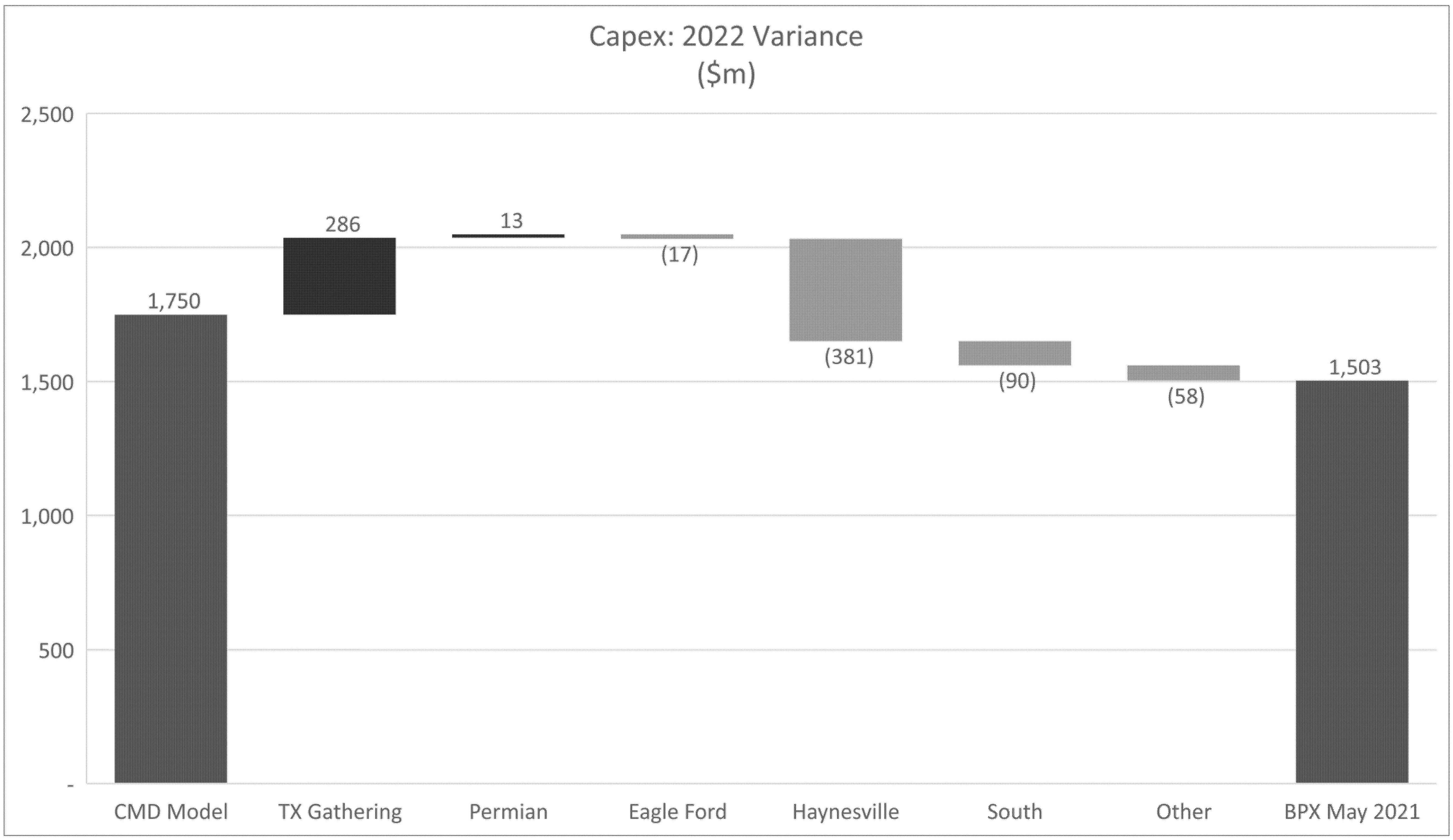


Unit Cash Costs ($ per BOE)	2020	2021	2022	2023	2024	2025	2026	2027
Permian	$13.9	$12.6	$11.1	$10.9	$12.3	$10.8	$10.5	$10.3
Blackhawk	$11.5	$13.7	$14.1	$13.1	$13.7	$11.0	$10.2	$9.7
Hawkville	$8.0	$10.2	$9.3	$9.1	$10.5	$10.0	$9.8	$9.8
Louisiana Haynesville	$4.9	$6.5	$5.7	$5.5	$5.0	$4.5	$4.0	$3.7
Texas Haynesville	$3.3	$4.2	$4.3	$5.8	$6.2	$5.7	$5.2	$4.7
South	$4.4	$4.2	$3.8	$3.5	$2.0	$3.1	$2.4	$2.3
Total bpx (Gross)	$10.2	$11.1	$10.9	$10.8	$10.6	$9.8	$9.5	$9.1
Intercompany	$1.4	$1.9	$2.2	$2.5	$2.0	$2.3	$2.5	$2.5
Total bpx (Net)	$8.8	$9.2	$8.7	$8.3	$8.5	$7.5	$7.0	$6.6

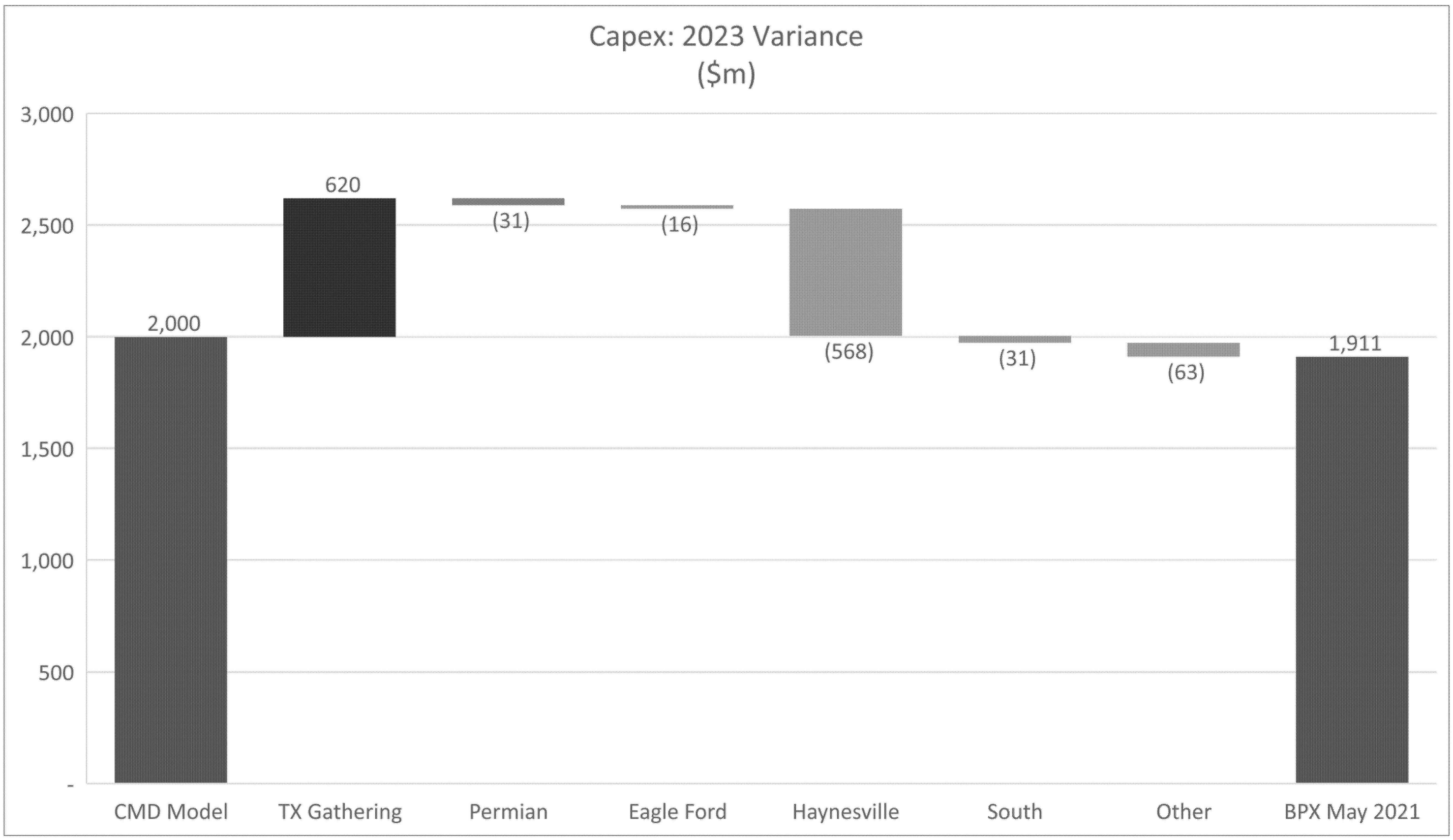
Capex: comparison to capital markets days (CMD) case



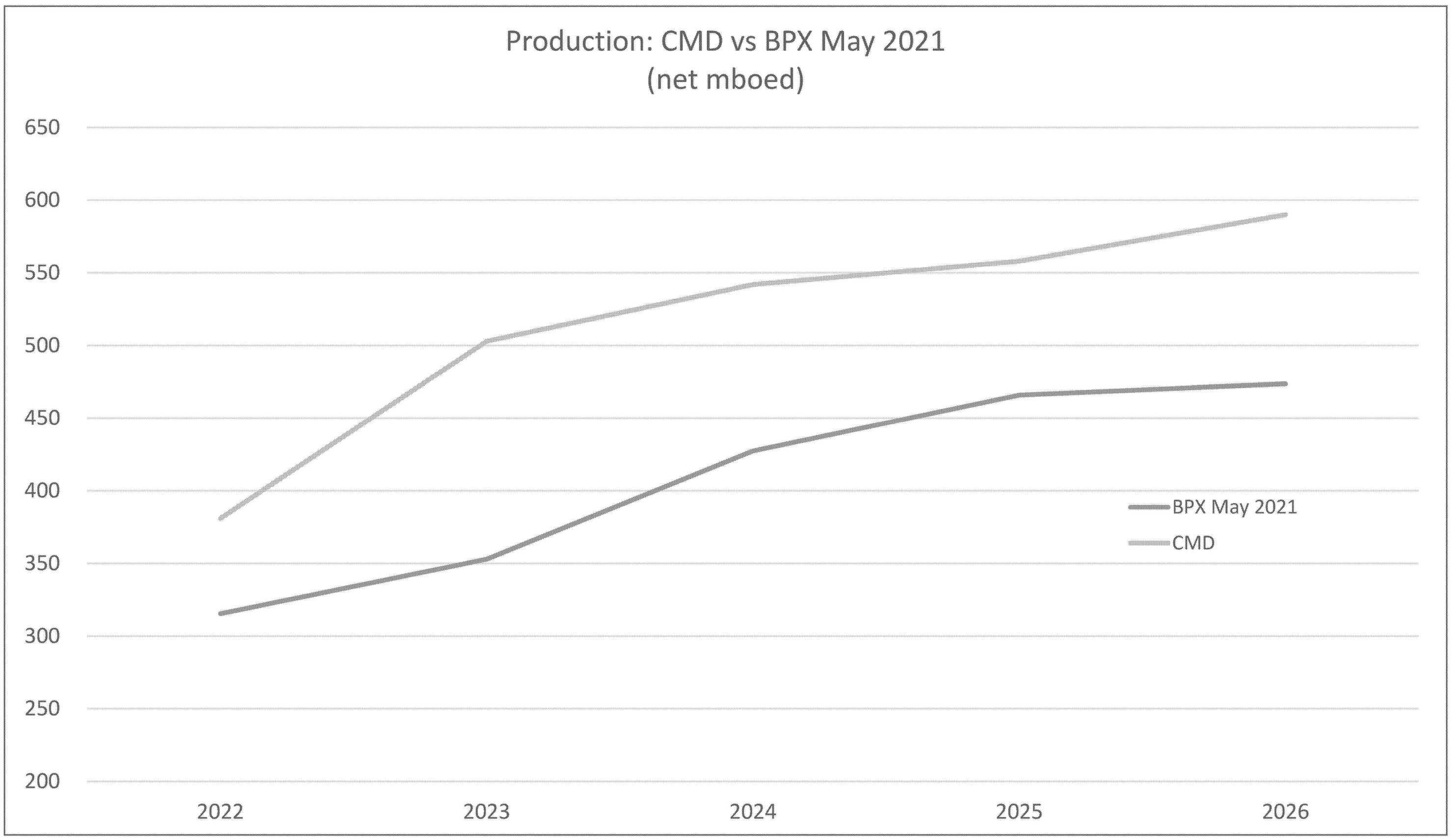
Capex: comparison to capital markets days (CMD) case



Capex: comparison to capital markets days (CMD) case



Production: comparison to capital markets days (CMD) case



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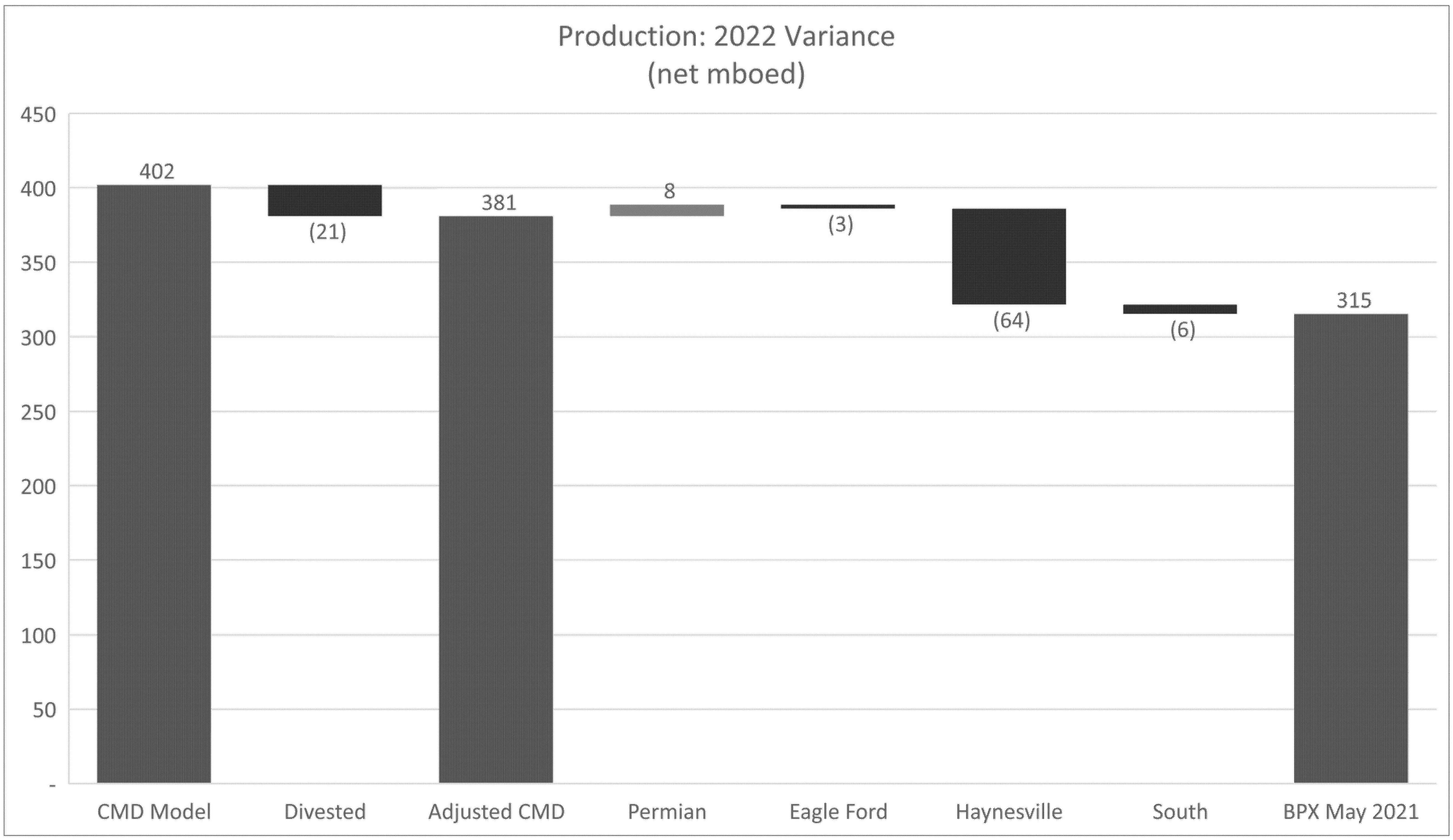
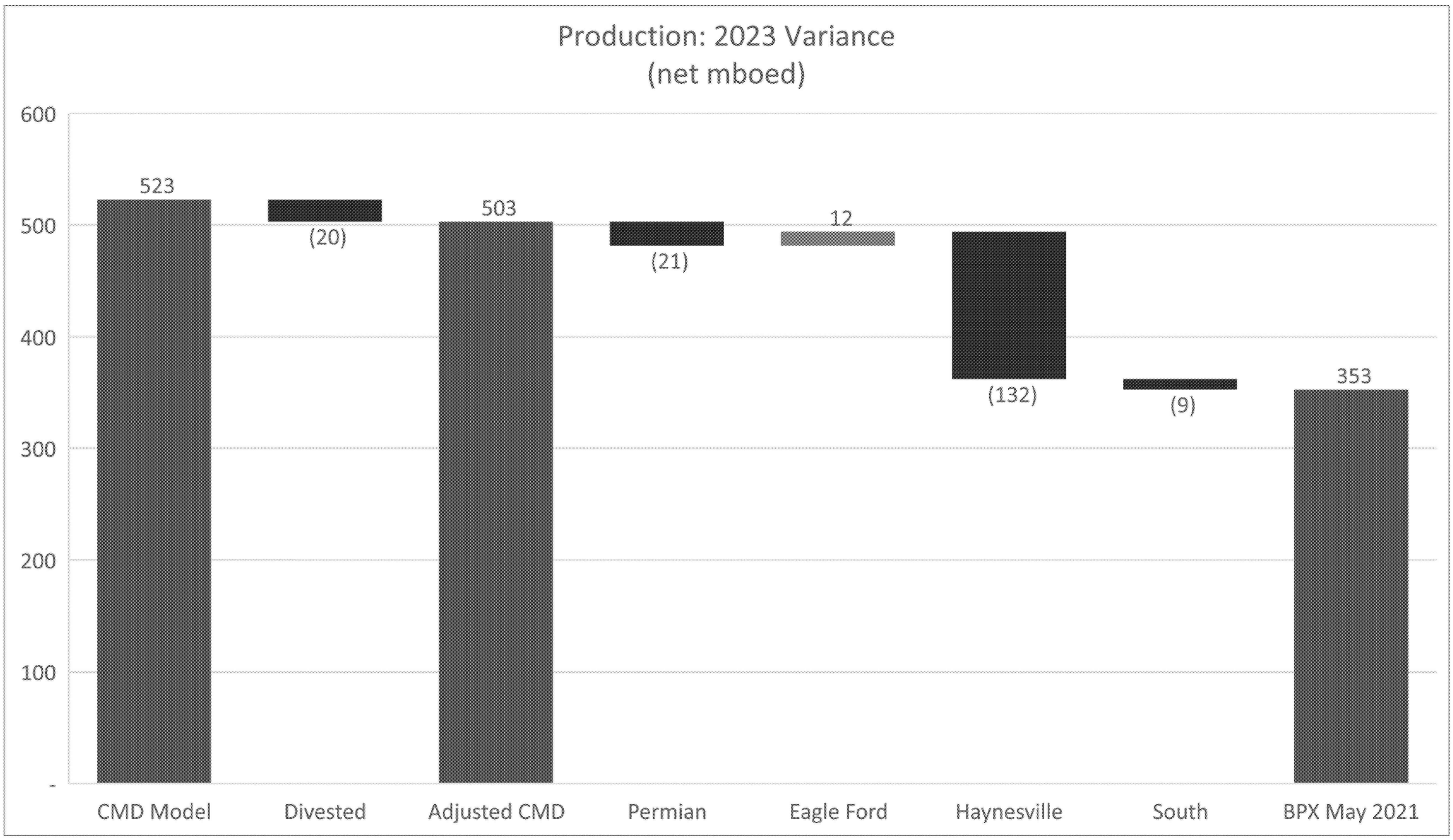
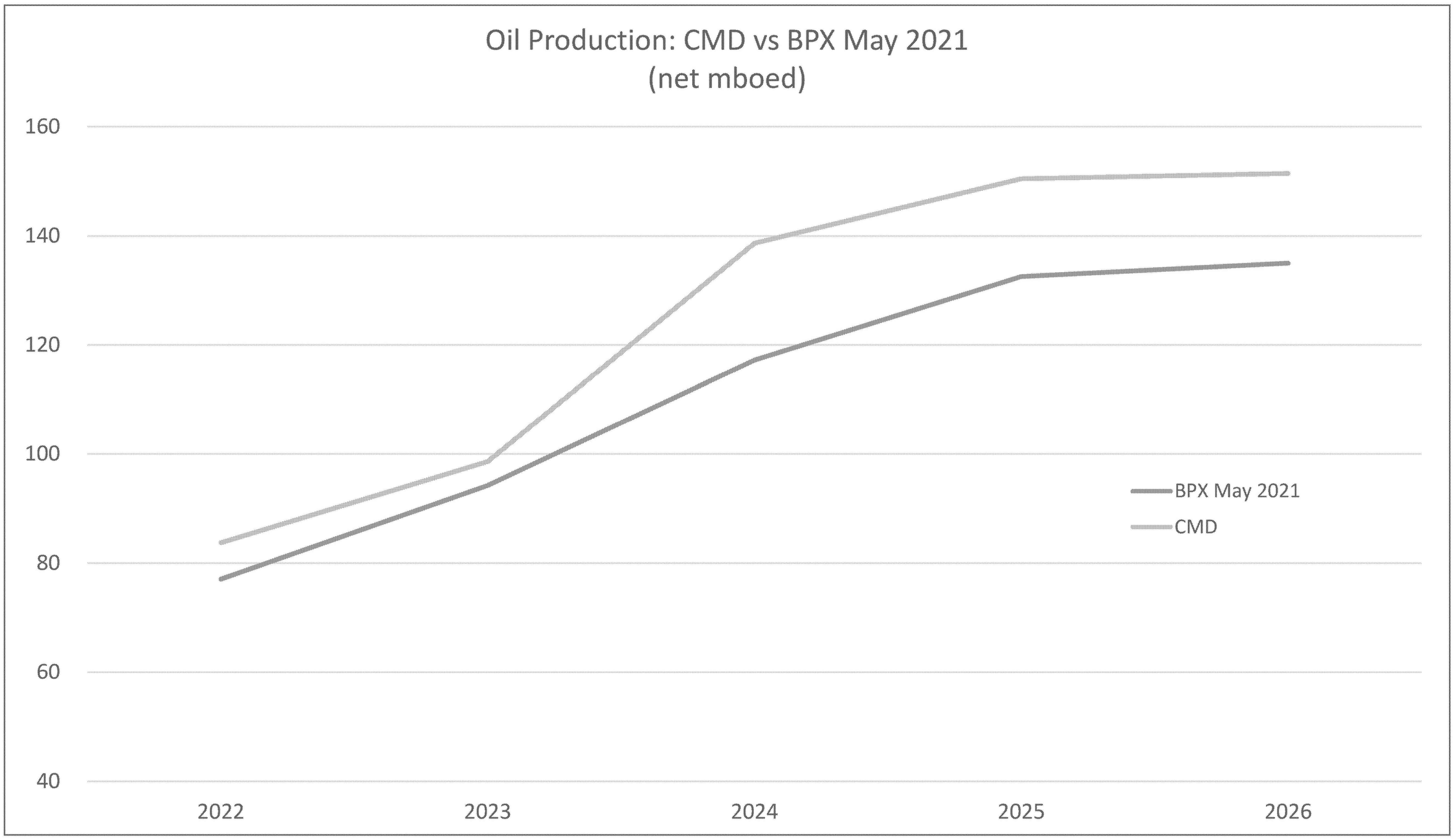
Production: comparison to capital markets days (CMD) case



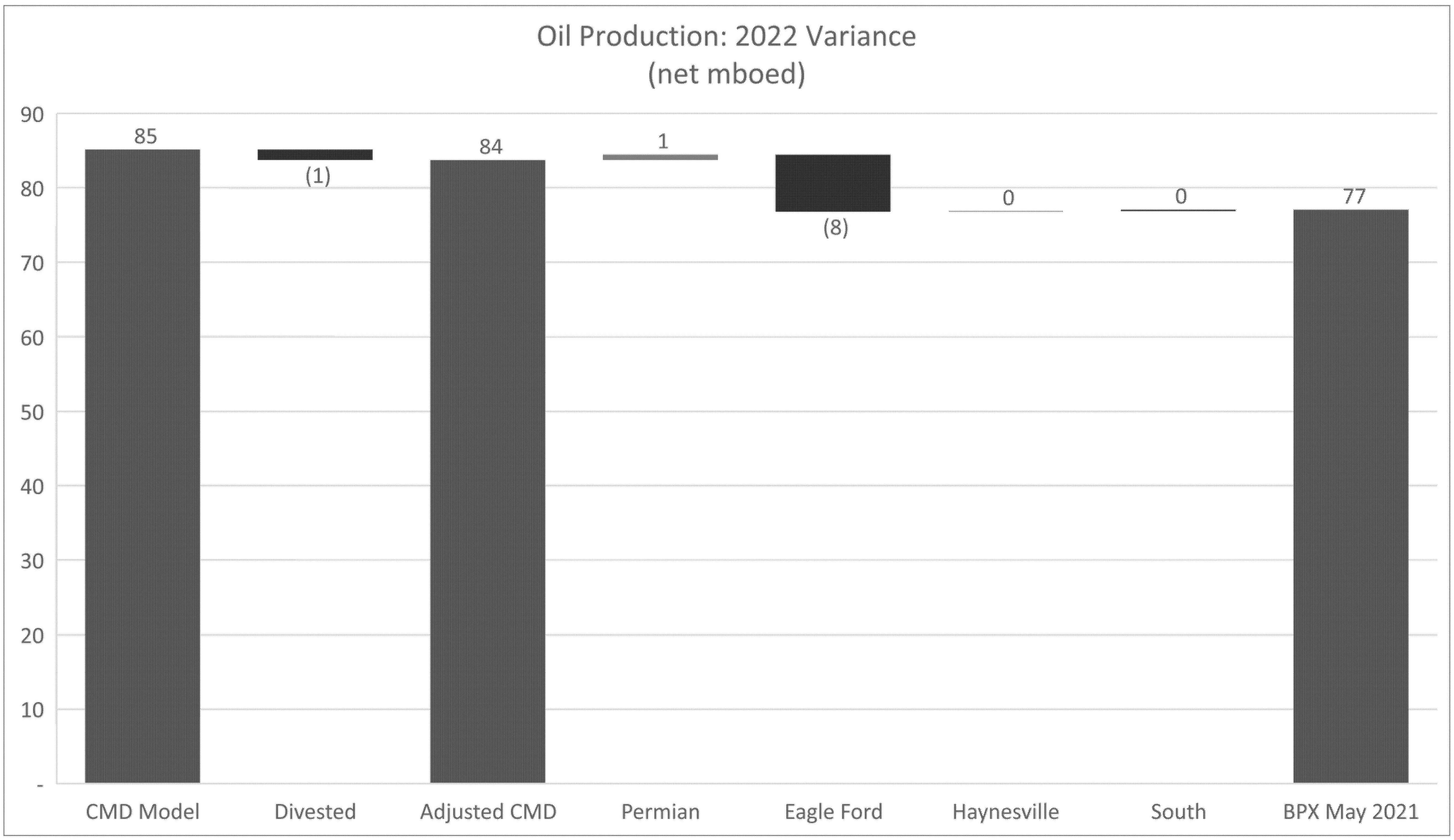
Production: comparison to capital markets days (CMD) case



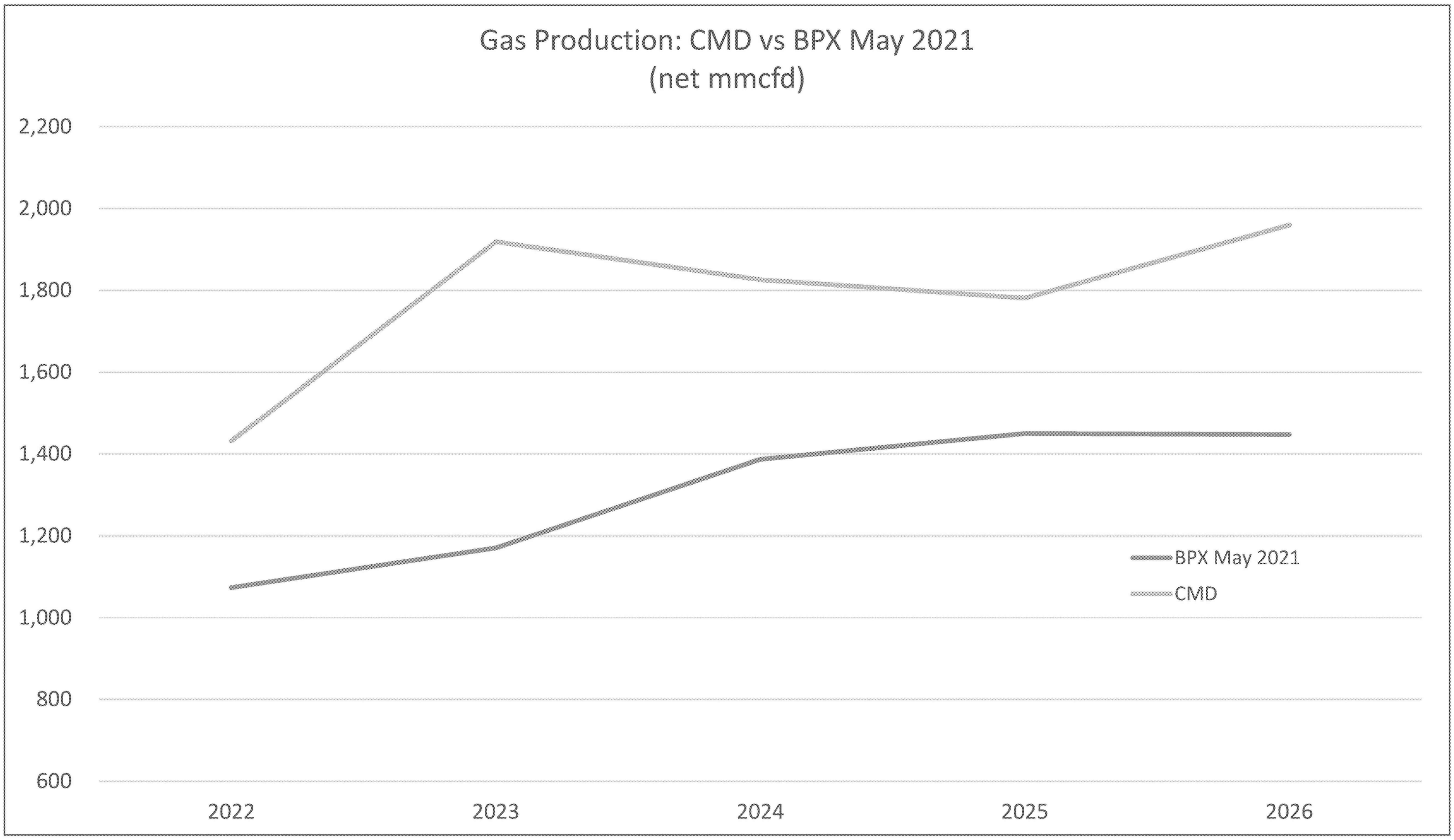
Oil production: comparison to capital markets days (CMD) case



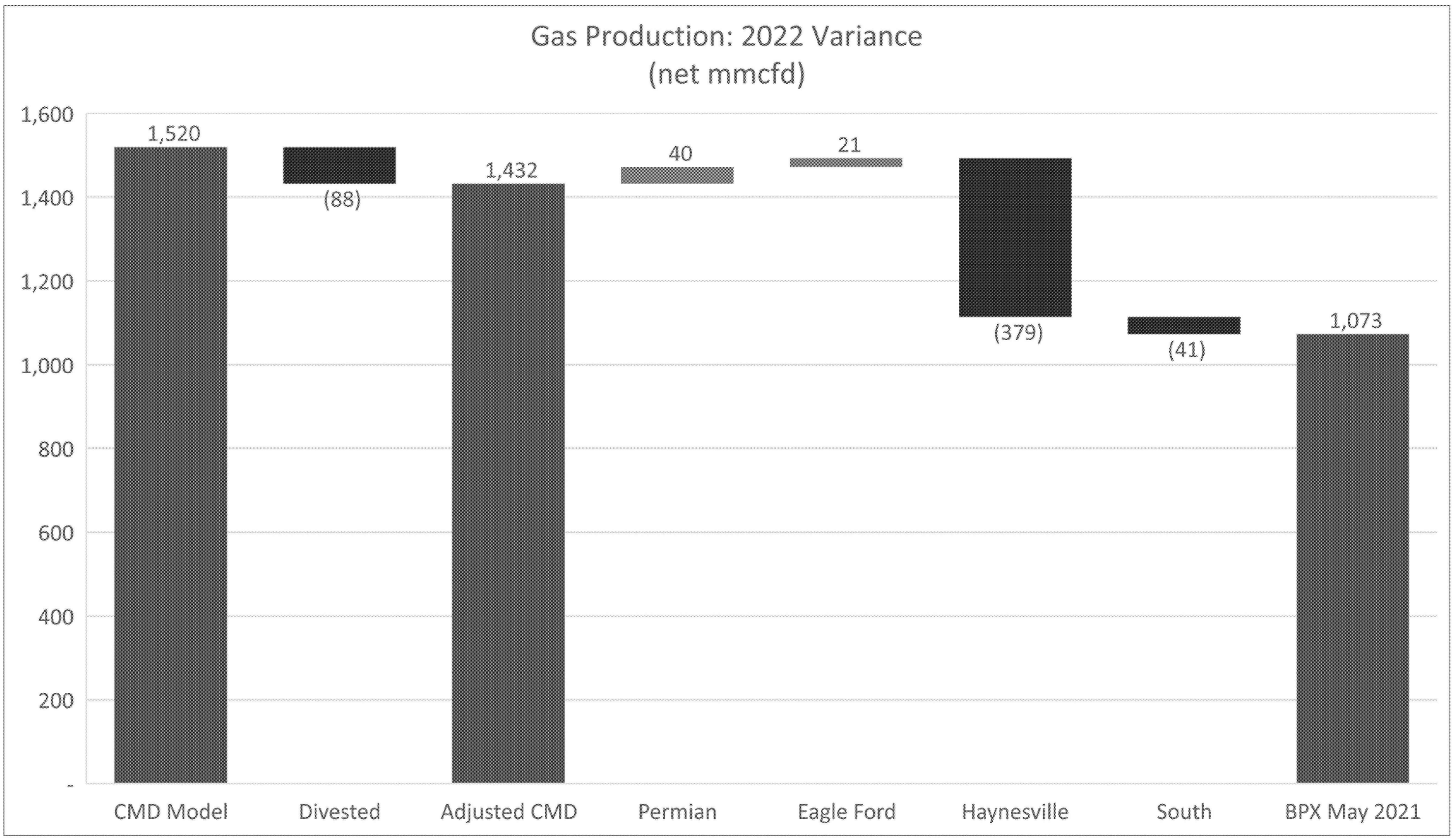
Oil production: comparison to capital markets days (CMD) case



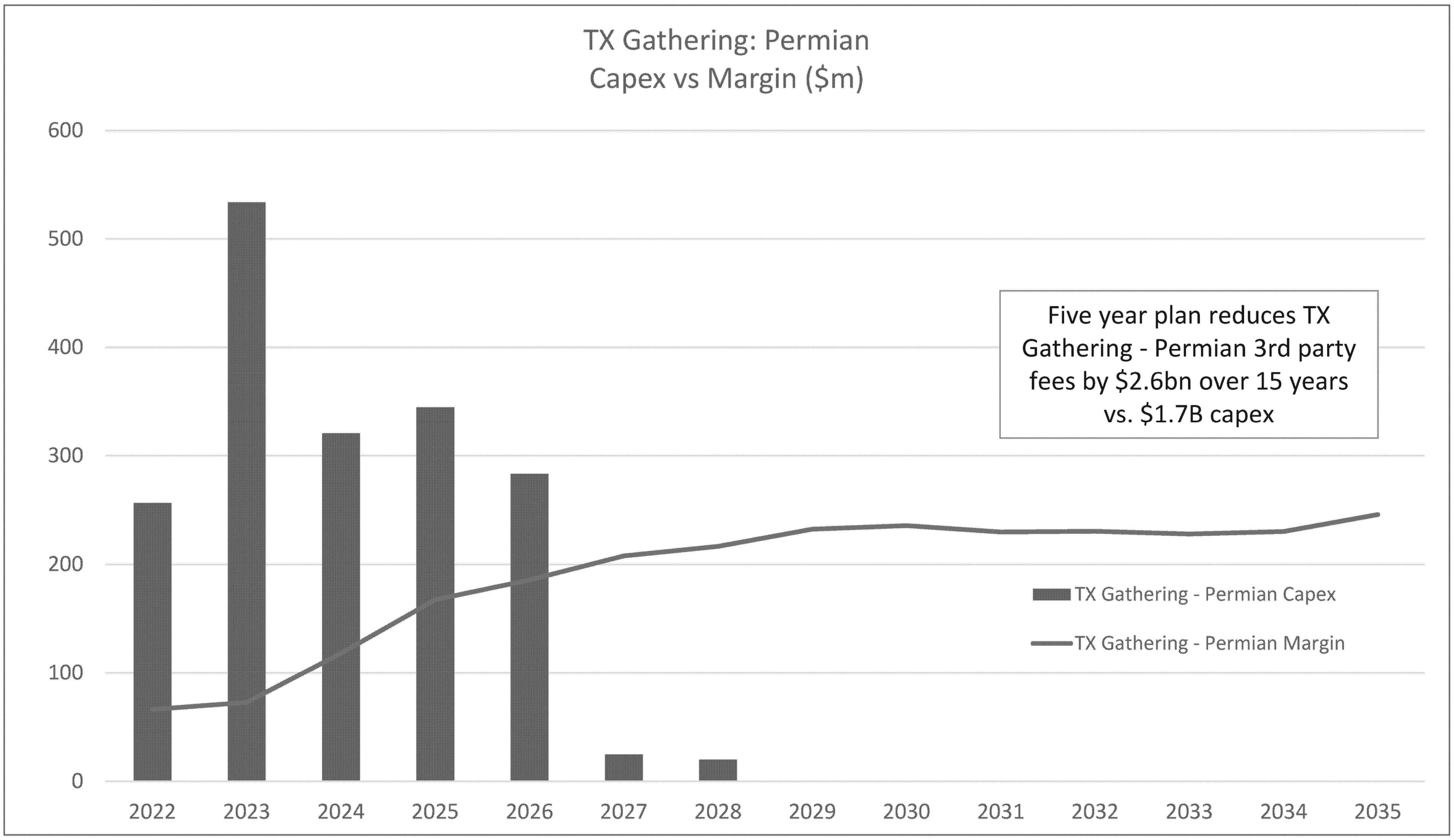
Gas production: comparison to capital markets days (CMD) case



Gas production: comparison to capital markets days (CMD) case



TX Gathering - Permian: short term capex vs long term margin



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1) Assumes organic funding of TX Gathering - Permian Capex
2) Margin defined as infrastructure revenue (including intercompany) less infrastructure opex

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Strategic Considerations

Strategy by basin

Redacted - Commercially Sensitive Material

- **Challenges:**
  - Commodity price fluctuations during growth phase (2022 – 2024) when significant % of capex is investing in infrastructure
    - *Mitigant: hedge crude oil from 2022-2024*
  - Although bpx recommends funding infrastructure organically, infrastructure spend is still naturally dilutive to cash generation near-term (vs. D&C investment)

Redacted - Commercially Sensitive Material

Permian development investment highlights

- 914 Core Wolfcamp A locations generate average 64% IRR (37-173%) when flowing through a bpx Central Delivery Point (CDP)
- 327 Bone Spring Locations could capitalize on success of 2020 State Kate Olson B208H, yields 183% IRR, highest 2BSS IP30 in Texas
- Sweet spots identified and upgraded in Wolfcamp B and XY targets for upside of 69% and 49% IRR, respectively for ~1,000 locations

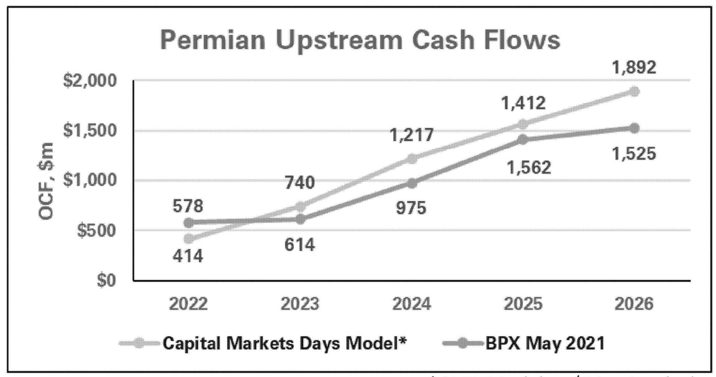
Challenges

- Development dependent on infrastructure build out

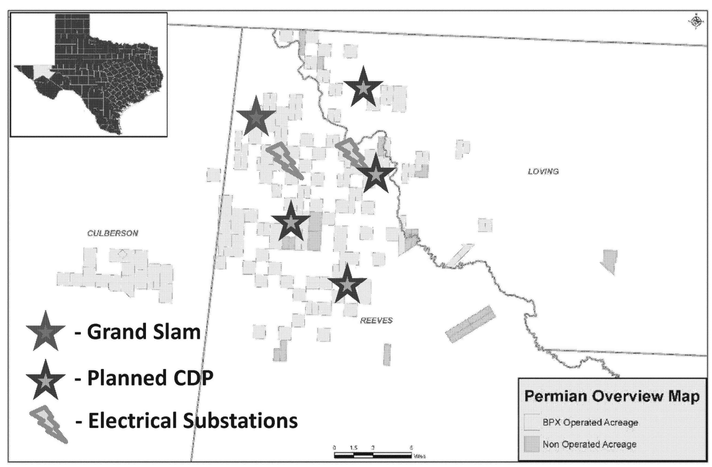
Key Statistics	
Net Acreage	83,304
Operated Avg. WI / Lse Net	97% / 75%
Net Production (FY21, mboed)	**69.7**
Gross Producing Wells	308
Gross Operated Technical PUD Inventory	1,461
Gross Operated Undeveloped Inventory through CR1	3,348
Gross OBO Undeveloped Inventory through CR1	238
Total Undeveloped Inventory through CR1	**3,586**

Asset Value	
PDP Reserves, Net mmboe	123
PUD Reserves, Net mmboe	669
Total Proved Reserves, Net mmboe	**792**
CR1 Resource, Net mmboe	2,275
Total Resource, Net mmboe	**3,067**
Total Resource, Net bcfe	17,789
Total Resource PV6, $bn	$14.2
Total Resource PV10, $bn	**$7.1**
PV10 per boe, $	$2.31

Note: All Reserves / Resource / Location numbers are at YE2020



*CMD Model at $50 price deck



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Permian development optimized for CDP utilization

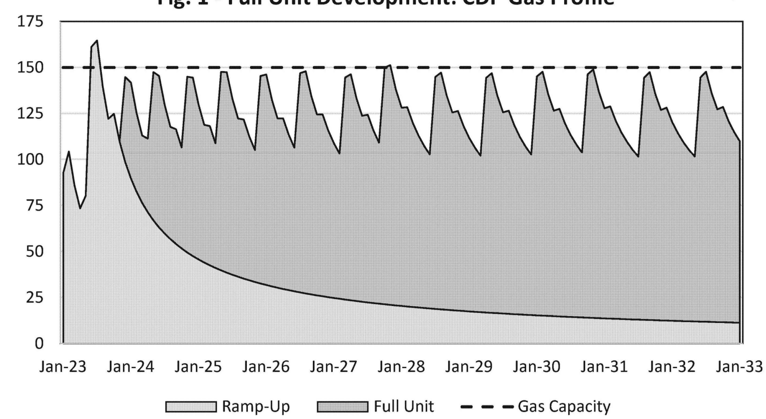
Bingo CDP needed August 2023, followed by Area D / Check Mate CDP April 2024

- Each CDP has an aggressive ramp-up of 4 full units (~40 wells) POL over 6 months to accelerate infrastructure project returns
- Rig Schedule alternating between CDPs to remain at or below capacity
- After ramp-up period, can either drill full units or half units

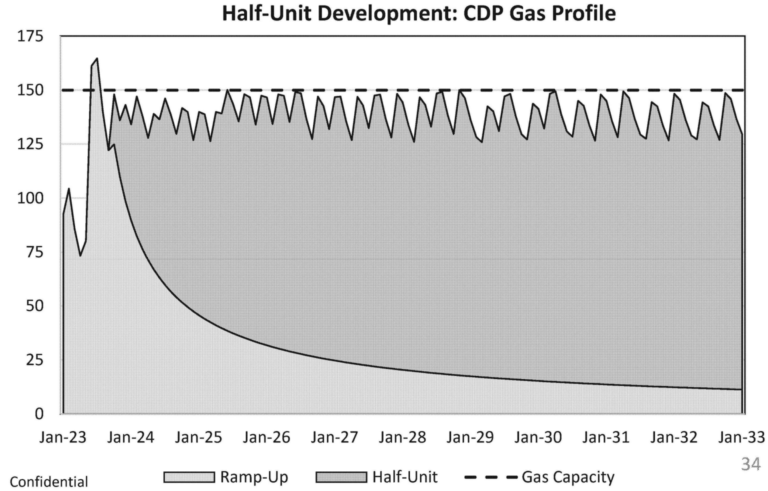
- **Full-Unit Dev Approach (Current):**
  - Visit peaks at 15 mbod, 65 mmcfd, 60 mbwd gross
  - Maintaining high utilization requires $150m/year to 10 wells every 8 mos
  - 3 rigs running flat could keep 2 CDPs full (Fig. 1)

- **Half-Unit Dev Approach:**
  - Visit peaks at 8 mbod, 32 mmcfd, 30 mbwd gross
  - Maintaining high utilization requires $200m/yr to drill 5 wells at 4 half-units per year
  - Can run ~2 rigs flat to fill a CDP
  - Maintains higher average utilization
  - Cash Flow maximized on gathering entity side
  - Potential depletion risk if return visits not performed within one year

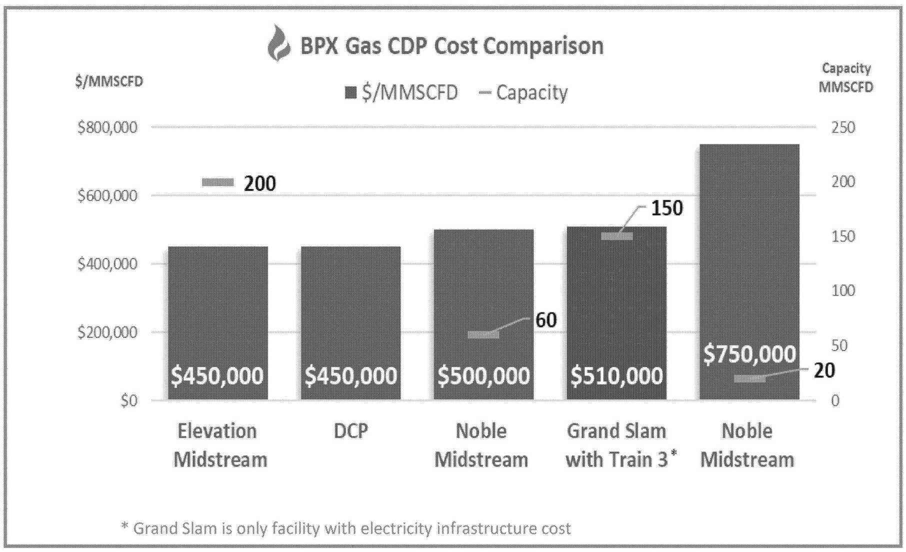
Fig. 1 - Full Unit Development: CDP Gas Profile



Half-Unit Development: CDP Gas Profile



Permian infrastructure: operated CDP track record



bpx Infrastructure Team Delivery to Date:

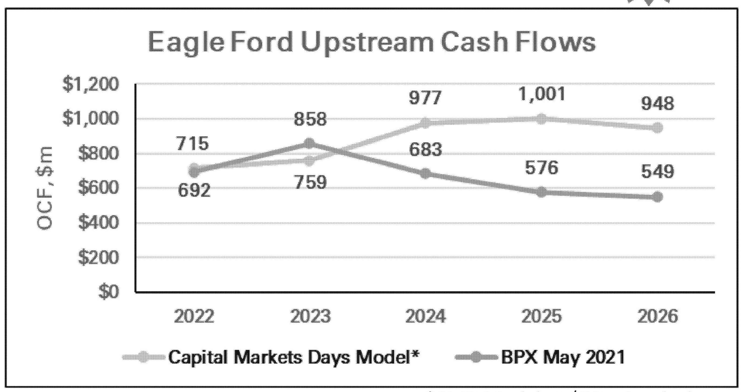
- Grand Slam largest US Onshore infrastructure project ($311m)
- Design, procurement, construction and commissioning took just over 12 months
- Exceptional safety performance during project delivery with over 600,000 manhours worked to date with zero OSHA recordables and 1 HiPO (no injuries)
- CDP capacity of 100 mmscfd and 26 kbopd (expandable to 150 mmscfd and 40 kbopd)
- SWD capacity of 120 kbwpd (equivalent to 8 Olympic size swimming pools per day)
- Electrical substation and distribution network with a capacity capable of powering all residential homes in Denver (with option to purchase 100% green energy)

Eagle Ford investment highlights

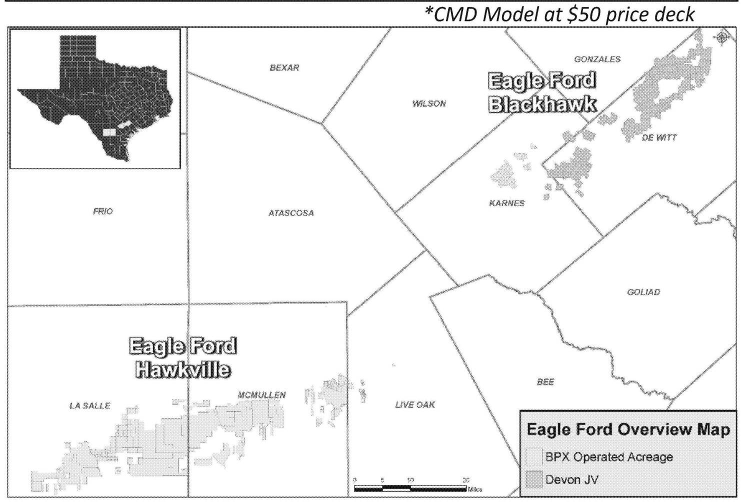
- **Karnes:** Liquids-rich Eagle Ford program generates 90+% IRR and 2.0+ CFE3; integrated low pressure and electrified gathering system makes it the most sustainable liquids play in the Eagle Ford portfolio. (electrified, centralized, tankless, flareless)

- **Black Hawk:** Southwest Co-Development liquids inventory delivers 90+% IRR and 1.9+ CFE3; EOR trial replicating EOG success and indicating 1.3x – 1.7x uplift and a 300+ MMBO potential across the bpx assets to begin Q4 '21

- **Hawkville:** Low-Yield/Mid-Yield Condensate inventory averaging 40-100 bbl/mmscf CGR at the wellhead delivers 1.7+ CFE3 across 330 locations; EUR increases as high as 80% realized year over year across the fluid window, provides optionality for enhanced rich gas with upside to type curve



*CMD Model at $50 price deck



Key Statistics	
Net Acreage	377,396
Karnes Operated Avg. WI / Lse Net	91% / 79%
Devon JV Avg. WI / Lse Net	49% / 76%
Hawkville Operated Avg. WI / Lse Net	94% / 76%
Net Production (FY21, mboed)	**92.6**
Gross Producing Wells	1,698
Gross Operated Technical PUD Inventory*	185
Gross Operated Undeveloped Inventory through CR1*	**1,955**

Asset Value	
PDP Reserves, Net mmboe	102
PUD Reserves, Net mmboe	83
Total Proved Reserves, Net mmboe	**185**
CR1 Resource, Net mmboe	479
Total Resource, Net mmboe	**664**
Total Resource, Net bcfe	3,851
Total Resource PV6, $bn	$2.9
Total Resource PV10, $bn	**$1.9**
PV10 per boe, $	$2.91

**Operated Count includes Devon JV*

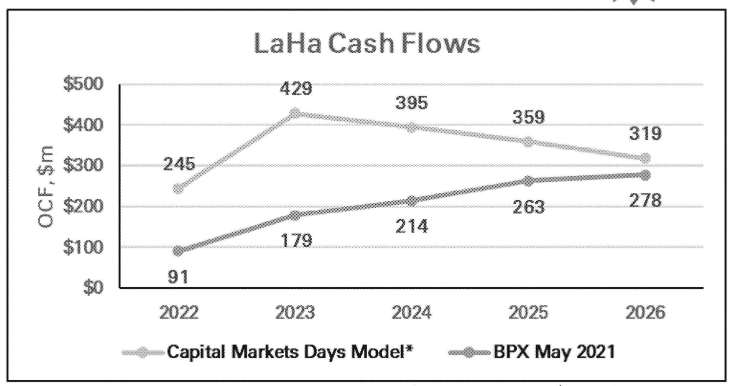
Note: All Reserves / Resource / Location numbers are at YE2020

Redacted - Commercially Sensitive Material

Redacted - Commercially Sensitive Material

LA Haynesville (LaHa) investment considerations

- Development focused on ***retaining leasehold*** and drilling leases at risk due to marginal production from current Single Wells on Lease (SWOL)
- LaHa dry gas locations, better risk-return profile than SoHa due to lower pressures due to ~3000' shallower TVD, increased well control for execution & performance and reduced overburden complexity

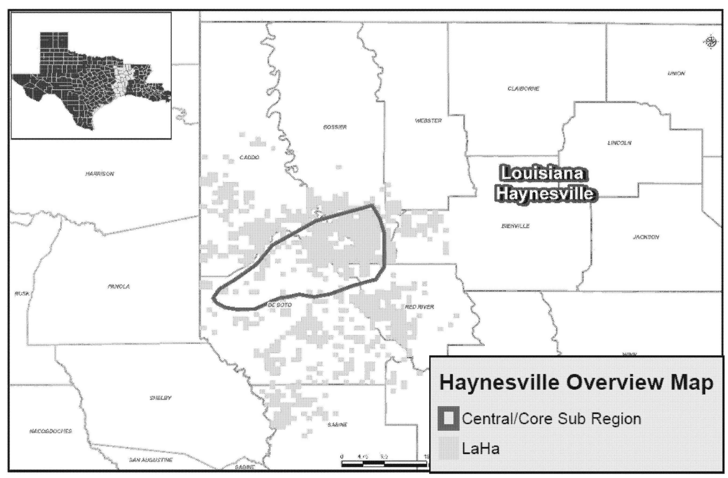


**CMD Model at $50 price deck*

Key Statistics	
Net Acreage	189,067
Operated Avg. WI / Lse Net	79% / 76%
Net Production (FY21, mboed)	**38.7**
Gross Producing Wells	1,052
Gross Operated Technical PUD Inventory	586
Gross Operated Undeveloped Inventory through CR1	1,041
Gross OBO Undeveloped Inventory through CR1	1,783
Total Undeveloped Inventory through CR1	**2,824**

Asset Value	
PDP Reserves, Net mmboe	66
PUD Reserves, Net mmboe	207
Total Proved Reserves, Net mmboe	**273**
CR1 Resource, Net mmboe	1,296
Total Resource, Net mmboe	**1,569**
Total Resource, Net bcfe	9,100
Total Resource PV6, $bn	$3.0
Total Resource PV10, $bn	**$1.6**
PV10 per boe, $	$0.99

Note: All Reserves / Resource / Location numbers are at YE2020



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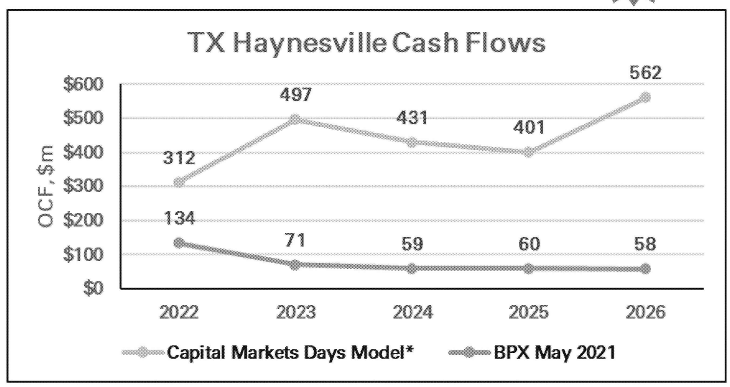
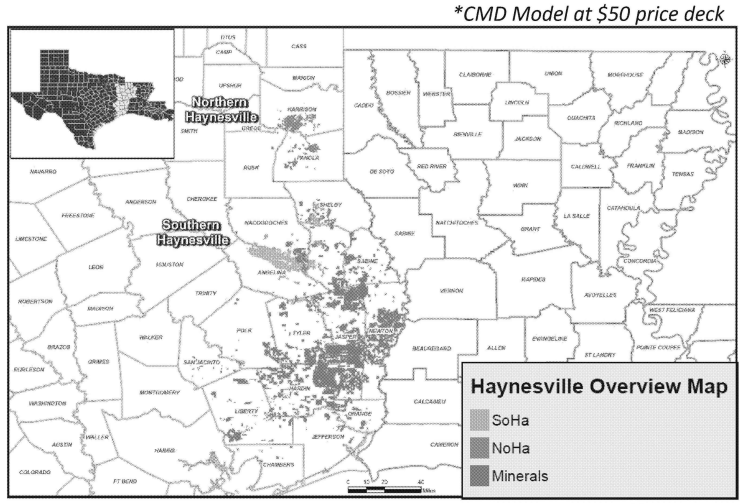
TX Haynesville investment considerations

- Austin Chalk Tex Mex prosect, currently highest 3-yr CFE in Portfolio at March STRIP at 2.2, delineation required to de-risk 300 development locations
- 2021 completion and production trials could yield incremental 13% IRR (STRIP) to 61% making it competitive with rich gas and condensate plays



*CMD Model at $50 price deck



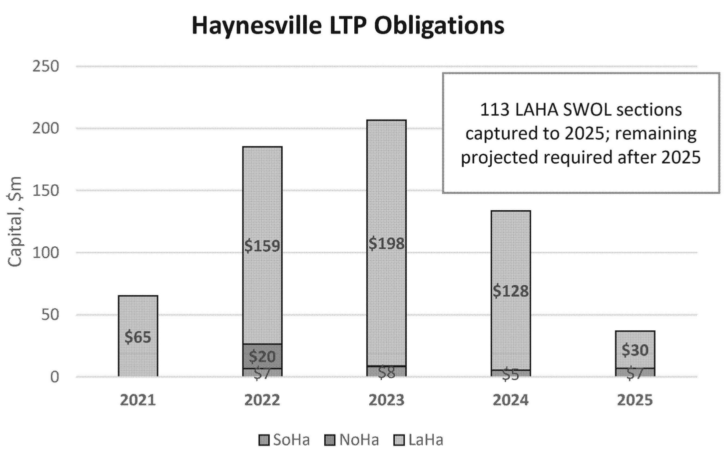
Key Statistics	
Net Acreage	916,442
Operated Avg. WI / Lse Net	90% / 85%
Net Production (FY21, mboed)	**41.7**
Gross Producing Wells	954
Gross Operated Technical PUD Inventory	77
Gross Operated Undeveloped Inventory through CR1	483
Gross OBO Undeveloped Inventory through CR1	335
Total Undeveloped Inventory through CR1	**818**

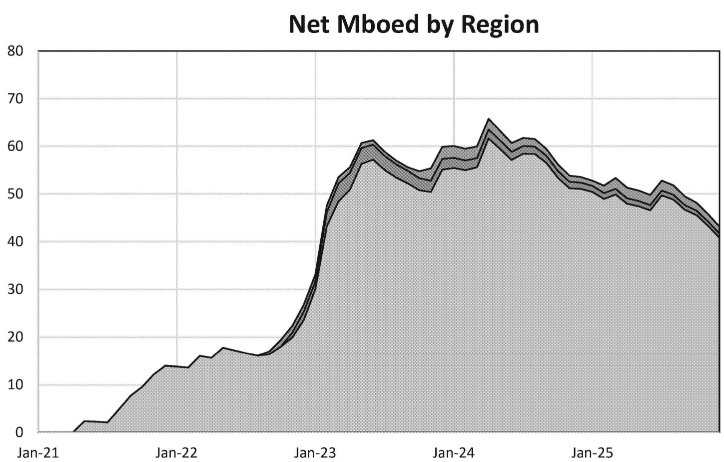
Asset Value	
PDP Reserves, Net mmboe	36
PUD Reserves, Net mmboe	14
Total Proved Reserves, Net mmboe	**50**
CR1 Resource, Net mmboe	388
Total Resource, Net mmboe	**438**
Total Resource, Net bcfe	2,540
Total Resource PV6, $bn	$1.1
Total Resource PV10, $bn	**$0.6**
PV10 per boe, $	$1.47

Note: All Reserves / Resource / Location numbers are at YE2020

Total Haynesville obligation needs

$628m obligation drilling protects leasehold position





		CAPITAL						POL					
	AREA	2021	2022	2023	2024	2025	Total	2021	2022	2023	2024	2025	Total
Obligation	SOHA	$0	$7	$8	$5	$7	**$28**	0	1	1	0	1	**3**
	NOHA	$0	$20	$0	$0	$0	**$20**	0	1	1	0	0	**2**
	LAHA	$65	$159	$198	$128	$30	**$580**	6	7	24	17	6	**60**
	AUSTIN_CHALK	$0	$0	$0	$0	$0	**$0**	0	0	0	0	0	**0**
	TOTAL	**$65**	**$185**	**$207**	**$134**	**$37**	**$628**	**6**	**9**	**26**	**17**	**7**	**65**

Focus Area for Plan

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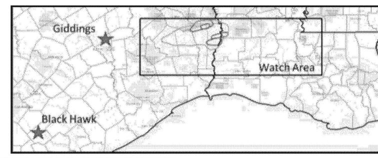
Haynesville Austin Chalk activity

Activity moving towards bpx minerals in East Texas & Western Louisiana



Zarvona Mann 1H (BSM)
Permitted 4/7/21

Prime Rock

Crosby 10 (Spud 10/19)
6k LL, 2200 lbs/ft, 1824 BOPD,5.4 mmcfd, 11928 bwpd

Crosby 33H
(spud 3/21)
Drilling

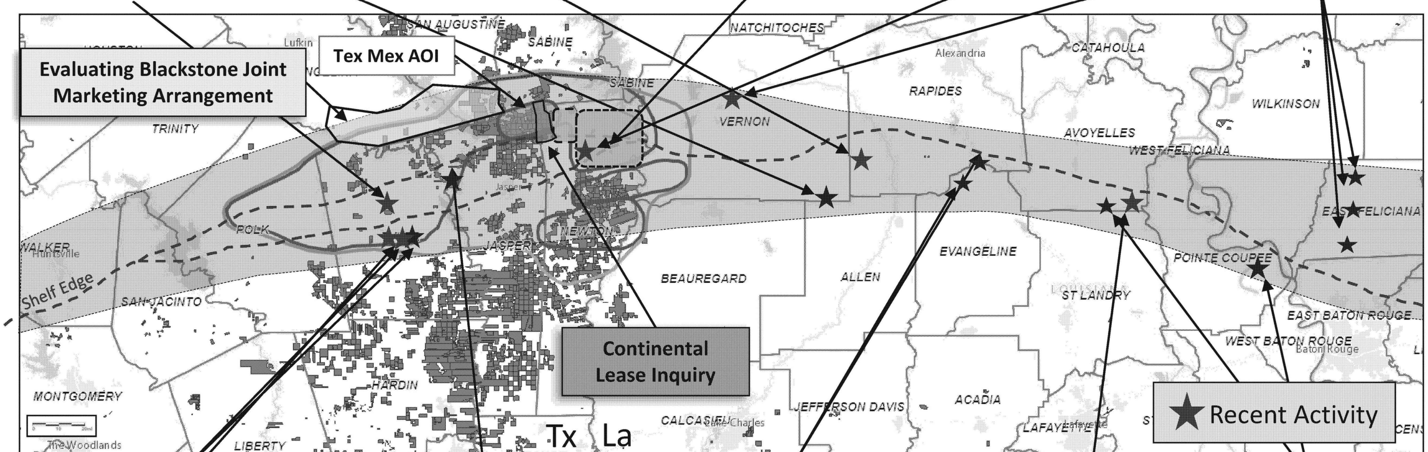
Continental
Rumored to be leasing BSM & CVX

Prize Exploration / RKI

Gibbs 2H
spud 12/20,6K LL
Prod not public

Maur 1H
Permit (1/21)

Conoco
Exited Play
Low BOPD & high water rates



Navidad
Hooper 1H: Permit (3/21)

Hancock 2H : Permit (6/20)
Reported as drilled, LL 7.7k

Hancock 1H (spud 8/19)
1508bopd,9.8 mmcfd,6364 psi ftp
0.85 psi/ft,6.2k LL,25stgs,2100ppf
Cum(11/20) 63mbo,1.9bcf,186 mbw

SM
Cameron Heirs 2H (PoP 12/14)
440bopd,3.4mmcfd,4700psi ftp
6.1k LL, 24stgs, 1800ppf
Cum 1.0bcf, 84mbo, 318mbw

Marathon
Crowell LM 30 #2 (comp 1/20)
210 bopd, 1650 mcfd, 8200 ftp, ~6x water
6215 LL
IR presentation reports 2650 boepd

Crowell LM 3H (spud 2/20)
Suspended all exploration capital activity in April 2020

White River Op
Deshotels 24H
(TD 2/22/21)

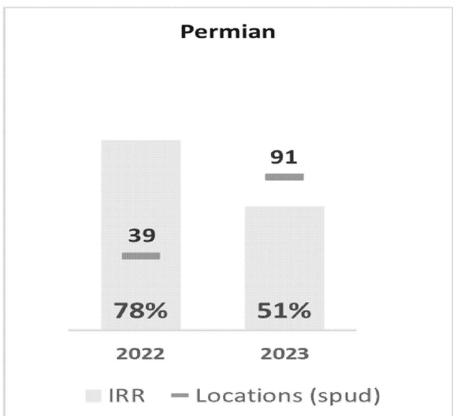
EOG
Eagles Ranch (comp 9/17)
1120 Bopd IP
Cum 158 mbo,157 mmcf
441 mbw

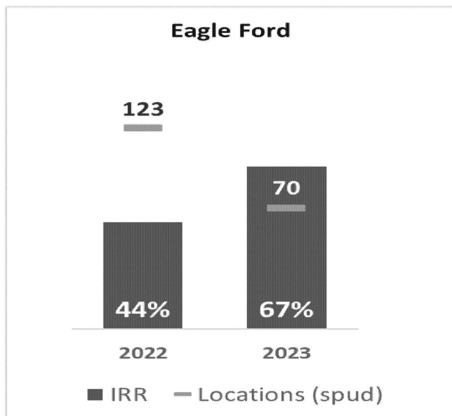
Brunswick Spud 6/19
Well has been fracd
No prod reported yet

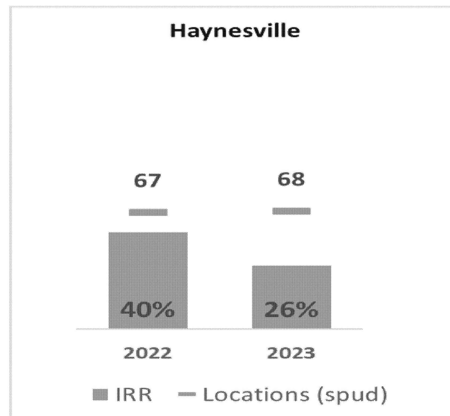
Redacted - Commercially Sensitive Material

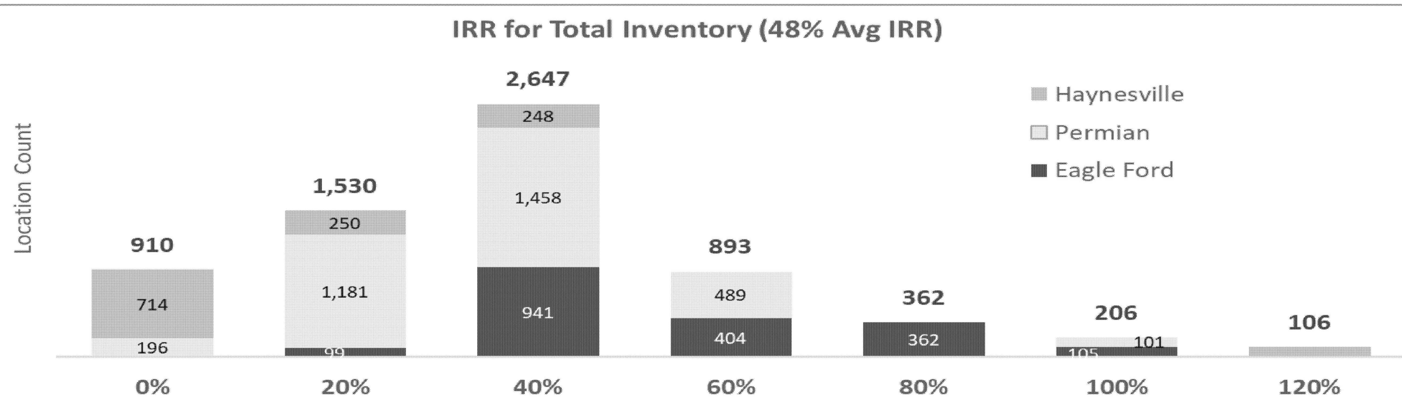
Investment returns by asset

IRR 2022-2023:







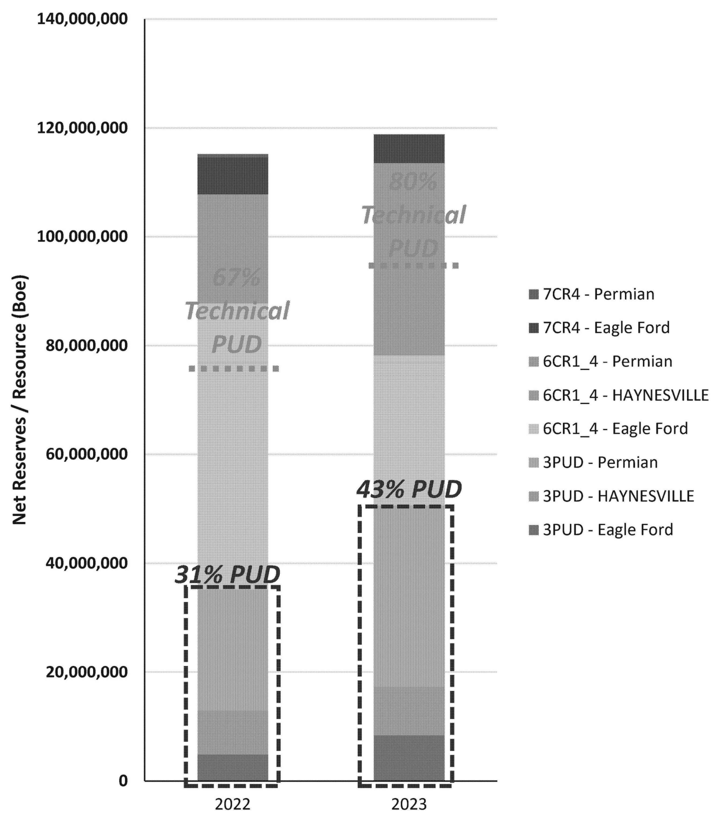


*Economics referenced run at March 21 strip prices

Plan resource progression

High technical PUD conversion underpins confidence in plan delivery

- 115 mmboe progressed to PD in 2022
  - 36 mmboe of PUD conversion (31%)
  - 77 mmboe of technical PUDs converted (67%)
- 119 mmboe progressed to PD in 2023
  - 51 mmboe of PUD conversion (43%)
  - 95 mmboe of technical PUDs converted (80%)
- Development program to replace drilled PUD reserves with large inventory of Technical PUDs ready to convert
  - 110 Technical PUDs ready to convert to PUD to replace ~65 mmboe of PUD reserves converted to PD
  - Additional Technical PUDs available outside of 2-year frame[1]



(1) Bpx May plan scheduled with discrete locations through 2023; utilized more generic EsiManage cases for 2024+
Note: All reserves / resource classifications and volumes as of NSAI YE2020 report

Business Development Considerations

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Plan vs. Recommended at GFO2 Prices

Long-term financial & operating plan @ GFO2 prices

BPX		2020	2021	2022	2023	2024	2025	2026	2027
Production	*mboed*	**373**	**276**	**315**	**354**	**427**	**466**	**474**	**528**
Oil	*mbbld*	72	64	77	94	117	133	135	151
NGL	*mbbld*	59	46	53	58	71	83	89	99
Gas	*mmcfd*	1,405	963	1,073	1,170	1,387	1,450	1,447	1,617
Gross Margin	*$m*	1,809	2,423	2,445	2,888	3,699	4,200	4,492	5,257
Total Cash Costs	*$m*	(1,063)	(922)	(985)	(1,019)	(1,332)	(1,277)	(1,215)	(1,271)
Unit Cash Costs	*$/boe*	*(7.8)*	*(9.2)*	*(8.6)*	*(7.9)*	*(8.5)*	*(7.5)*	*(7.0)*	*(6.6)*
DD&A	*$m*	(1,634)	(1,246)	(1,453)	(1,635)	(1,960)	(2,144)	(2,185)	(2,394)
RCOP	*$m*	(1,133)	168	8	234	407	779	1,092	1,592
Working Capital, Decomm & Provisions	*$m*	(245)	(107)	(107)	(47)	63	(47)	(32)	(59)
Ops Cash Flow	*$m*	**501**	**1,414**	**1,353**	**1,823**	**2,430**	**2,876**	**3,245**	**3,926**
Capex	*$m*	(1,003)	(948)	(1,504)	(1,912)	(2,000)	(2,000)	(2,000)	(2,000)
Capex Creditors	*$m*	(282)	48	84	68	15	0	(0)	0
Cash Capex	*$m*	**(1,284)**	**(900)**	**(1,420)**	**(1,844)**	**(1,985)**	**(2,000)**	**(2,000)**	**(2,000)**
Free Cash Flow	*$m*	(783)	514	(67)	(22)	445	876	1,245	1,926
For Reference									
Marker Price									
Oil	*$/bbl*	41.27	53.89	49.00	49.90	50.90	52.00	55.20	58.70
NGL	*$/bbl*	18.28	24.14	20.44	20.17	20.72	21.27	22.33	23.45
Gas	*$/mmcfd*	2.22	2.93	3.10	3.18	3.25	3.31	3.38	3.45
Realization Price									
Oil	*$/bbl*	34.91	50.51	47.39	48.26	49.23	50.41	53.56	56.97
NGL	*$/bbl*	10.60	17.23	13.70	13.51	13.88	14.43	15.46	16.55
Gas	*$/mmcfd*	1.29	2.91	2.98	3.06	3.13	3.17	3.23	3.30

Ops cash flow profile @ GFO2 prices

Ops Cash Flow ($mn)	2020	2021	2022	2023	2024	2025	2026	2027
Permian	118	454	469	551	912	1,415	1,675	2,037
Blackhawk	250	429	318	467	415	381	353	368
Hawkville	92	155	219	289	257	230	280	400
Louisiana Haynesville	(35)	49	121	185	326	378	400	529
Texas Haynesville	187	179	154	95	82	84	83	87
South	81	233	163	190	228	234	259	283
TX Gathering - Permian	30	33	86	97	163	239	269	304
TX Gathering - Eagle Ford Karnes	3	9	0	0	4	6	3	1
Midstream JV	118	98	115	131	112	96	100	118
Resid	(129)	(117)	(186)	(136)	(132)	(141)	(143)	(141)
Divest / Other	31	1						
Total bpx Ops Cash Flow (pre-WC)	**746**	**1,521**	**1,461**	**1,869**	**2,367**	**2,923**	**3,277**	**3,986**
Working Capital, Decomm. & Provisions	(245)	(107)	(107)	(47)	63	(47)	(32)	(59)
Total bpx Ops Cash Flow	**501**	**1,414**	**1,353**	**1,823**	**2,430**	**2,876**	**3,245**	**3,926**

Ops Cash Flow ($ per BOE)	2020	2021	2022	2023	2024	2025	2026	2027
Permian	5.7	19.2	16.3	17.4	17.7	19.4	20.7	22.6
Blackhawk	11.7	22.4	17.0	20.7	19.7	21.2	23.2	25.9
Hawkville	4.5	11.4	10.4	11.7	9.4	10.1	12.6	15.7
Louisiana Haynesville	(1.9)	3.5	6.0	6.9	9.9	11.9	13.1	13.9
Texas Haynesville	6.8	10.4	11.5	10.5	10.9	11.7	12.6	13.4
South	7.1	19.0	12.5	13.4	14.2	13.5	14.7	15.3
Total bpx Ops Cash Flow (pre-WC)	**6.2**	**15.2**	**12.7**	**14.5**	**15.1**	**17.2**	**19.0**	**20.7**

Free cash flow profile @ GFO2 prices

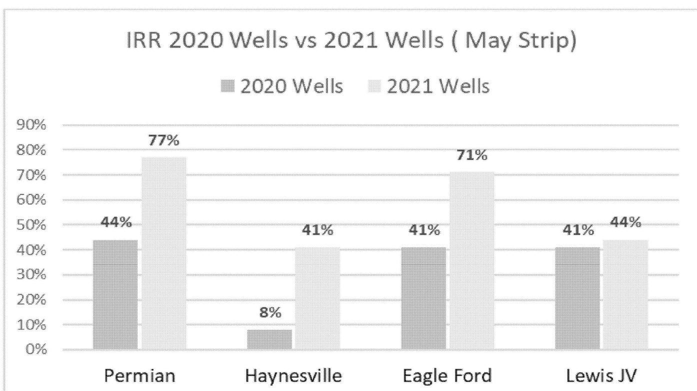
Free Cash Flow ($mn)	2020	2021	2022	2023	2024	2025	2026	2027
Permian	(108)	245	147	(22)	20	519	772	1,195
Blackhawk	(1)	204	(26)	242	204	194	240	221
Hawkville	48	63	(73)	106	147	96	(10)	26
Louisiana Haynesville	(27)	(75)	(45)	(28)	74	158	154	138
Texas Haynesville	144	132	154	95	125	127	151	175
South	59	173	98	125	125	127	151	175
TX Gathering - Permian	(224)	(47)	(170)	(437)	(158)	(106)	(15)	279
TX Gathering - Eagle Ford Karnes	(61)	(13)	(23)	(23)	4	6	3	1
Midstream JV	110	86	92	47	77	63	92	40
Resid*	(227)	(195)	(197)	(148)	(251)	(259)	(262)	(265)
Divest / Other	31	1						
Total bpx Free Cash Flow (pre-WC & CC)	(257)	572	(43)	(43)	367	923	1,277	1,986
Working Capital, Decomm. & Provisions	(204)	(107)	(107)	(47)	63	(47)	(32)	(59)
Capex Creditors	(282)	48	84	68	15	0	(0)	0
Total bpx Free Cash Flow - Organic	(742)	514	(67)	(22)	445	876	1,245	1,926
Divestment Proceeds	576	104	0	0	0	0	0	0
Total bpx Free Cash Flow - Reported	(166)	618	(67)	(22)	445	876	1,245	1,926

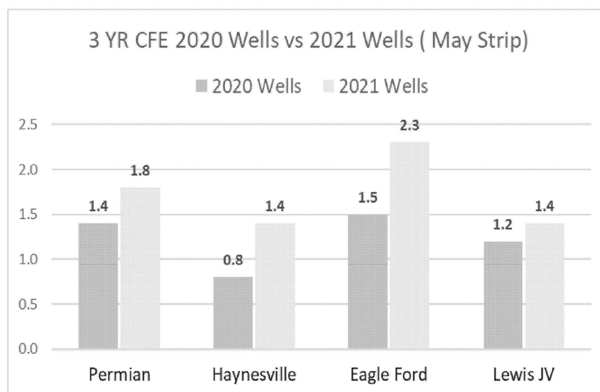
**2024+ Resid forecasts includes capitalized overhead. Capitalized overhead absorbed at BU levels over 2020-23.*

2020 and 2021 IQA Tables

2020 Wells vs 2021 Wells at May Strip

2020 vs 2021 Well Economics at May Strip	2020 Wells					2021 Wells				
		Net @ May Strip					Net @ May Strip			
BU	Number of Wells	IRR %	NPV6 $m	CF Eff 1 YR	CF Eff 3 YR	Number of Wells	IRR %	NPV6 $m	CF Eff 1 YR	CF Eff 3 YR
Permian	36	44%	283	0.5	1.4	23	77%	263	0.9	1.8
Haynesville	3	8%	0.8	0.4	0.8	36	41%	170	0.5	1.4
Eagle Ford	100	41%	228	0.8	1.5	86	71%	339	0.8	2.3
Lewis JV	13	41%	41	0.3	1.2	31	44%	78	0.6	1.4





bpx energy

Confidential

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Permian 2020 IQA at May 21 Strip Prices

2020 Permian New Well Economics			Latest Estimate				
			Gross	Net @ May 2021 Strip Prices			
Well Name	Lateral Length	WI %	Well Cost $m	IRR %	NPV6 $m	1 yr CF Effic. $ (Spud)	3 yr CF Effic. $ (Spud)
STATE GOODSPEED 57-T2-45X4 W108H	10,000	75%	12.0	72%	22.1	0.9	1.9
STATE PRIDE 57-T3-38 W207H	5,000	100%	8.7	42%	7.8	0.7	1.4
STATE TUNDRA 57-T3-26 W207H	5,000	100%	8.4	74%	13.0	0.9	1.7
STATE HEDBLOM 56-T3-24 W101H	5,000	100%	8.0	21%	3.2	0.5	1.0
STATE HEDBLOM 56-T3-24 W115H	5,000	100%	8.5	18%	3.1	0.4	0.9
STATE HEDBLOM 56-T3-24 W102H	5,000	100%	7.9	34%	4.8	0.7	1.2
STATE RUSH 57-T2-18 W108H	5,000	100%	8.8	13%	1.8	0.4	0.8
STATE MINT 57-T3-16 W201H	5,000	100%	8.2	7%	0.3	0.4	0.8
STATE MONEY 57-T3-20 W201H	5,000	100%	8.1	0%	-1.8	0.2	0.5
STATE CHAMP 56-T3-12X5 W206H	10,000	100%	11.7	35%	10.2	0.6	1.3
STATE LOST & FOUND 57-T2-20X17 9H	7,500	100%	8.3	37%	8.1	0.0	1.4
STATE LOST & FOUND 57-T2-20X17 8H	7,500	100%	8.4	52%	13.0	0.0	1.7
STATE LOST & FOUND 57-T2-20X17 7H	7,500	100%	8.8	32%	6.4	0.1	1.3
STATE LOST & FOUND 57-T2-20X17 W110H	7,500	100%	8.1	71%	14.3	0.4	1.9
STATE LOST & FOUND 57-T2-20X17 W106H	7,500	100%	7.6	60%	10.8	0.6	1.7
STATE LOST & FOUND 57-T2-20X17 W111H	7,500	100%	7.6	64%	13.4	0.5	1.8
STATE LOST & FOUND 57-T2-20X17 W105H	7,500	100%	7.9	57%	11.4	0.5	1.7
STATE LOST & FOUND 57-T2-20X17 W112H	7,500	100%	7.5	69%	13.1	0.7	2.0
STATE KATE OLSON 57-T2-17X8 W111H	7,500	100%	7.8	70%	13.4	0.8	1.9
STATE KATE OLSON 57-T2-17X8 W106H	7,500	100%	8.6	44%	8.4	0.7	1.4
STATE KATE OLSON 57-T2-17X8 W108H	7,500	100%	7.9	73%	13.6	0.6	1.9
STATE KATE OLSON 57-T2-17X8 W109H	7,500	100%	7.1	82%	14.2	0.8	2.1
STATE KATE OLSON 57-T2-17X8 W107H	7,500	100%	7.0	88%	13.4	0.9	2.1
STATE KATE OLSON 57-T2-17X8 W110H	7,500	100%	7.5	109%	15.5	1.1	2.4
STATE KATE OLSON 57-T2-17X8 B208H	7,500	100%	8.0	191%	25.0	1.6	3.4
HS STATE 113-16 W107H	5,000	100%	7.6	22%	3.5	0.4	1.1
HS STATE 113-16 W106H	5,000	100%	7.3	39%	6.3	0.5	1.4
STATE SKY HOOK 57-T2-24 W115H	5,000	100%	6.4	71%	10.0	0.7	1.9
STATE FLOYD 33-96X45 W104H	7,500	100%	10.1	0%	-3.2	0.2	0.5
STATE SKY HOOK 57-T2-24 W201H	5,000	100%	7.3	22%	3.2	0.4	1.1
CHEVY BLAZER 56-T3-20X17 W101H	10,000	100%	14.8	12%	2.9	0.4	0.8
STATE TUNSTILL 56-T2-15X10 W201H	7,500	100%	11.1	14%	3.0	0.3	0.9
CHEVY BLAZER 56-T3-20X17 W103H	10,000	0%	3.0	0%	-2.7	0.0	0.0
Permian CO 2020 ACB Year		**96%**	**8.4**	**45%**	**282**	**0.5**	**1.4**
WINGHEAD STATE 57-2-48 UNIT A 4H	7,500	1%	11.0	20%	0.1	0.3	1.0
WINGHEAD STATE 57-2-48 UNIT A 2H	7,500	1%	11.0	22%	0.1	0.2	1.0
WINGHEAD STATE 57-2-48 UNIT A 3H	7,500	1%	11.0	18%	0.1	0.2	0.9
ALLEN 55-2-44 LOV UNIT 3H	5,000	18%	6.3	0%	-0.2	0.5	0.7
BERNARD STATE C-27 2-5 LOV UNIT 4H	7,500	2%	8.5	117%	0.5	1.3	2.4
BERNARD STATE C-27 2-5 LOV UNIT 5H	7,500	2%	8.7	159%	0.7	1.5	2.9
SOUTH GOAT 2 UNIT 17H	10,000	6%	11.5	6%	0.0	0.3	0.8
SOUTH GOAT 2 UNIT 15H	10,000	6%	11.5	7%	0.0	0.4	0.8
NORTH GOAT 2 UNIT 12H	10,000	2%	11.5	12%	0.0	0.5	1.0
NORTH GOAT 2 UNIT 14H	10,000	2%	11.5	14%	0.0	0.5	1.0
SOUTH GOAT 2 UNIT 16H	10,000	6%	11.5	27%	0.3	0.5	1.1
NORTH GOAT 2 UNIT 11H	10,000	2%	11.5	19%	0.1	0.3	1.0
NORTH GOAT 2 UNIT 13H	10,000	2%	11.5	17%	0.0	0.3	1.0
Permian OBO 2020 ACB Year		**4%**	**10.5**	**20%**	**2**	**0.5**	**1.2**
Permian BU Total			**9.0**	**44%**	**283**	**0.5**	**1.4**

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Haynesville 2020 IQA at May 21 Strip Prices

2020 HV BU New Well Economics			Latest Estimate				
			Gross	Net @May21Strip Prices			
Well Name	Lateral Length	WI %	Well Cost $m	IRR %	NPV6 $m	1 yr CF Effic.	3 yr CF Effic.
ETX CO-OP Program							
ROO 2H	10,350	96%	25.2	8%	1.4	0.2	0.8
DRACOREX 1H	7,100	75%	17.7	4%	-1.1	0.5	0.8
XOM 17/8-9-13 H 1	8,533	20%	11.8	12%	0.5	0.4	0.9
HV BU			**18.2**	**8%**	**0.8**	**0.4**	**0.8**

Eagle Ford (Black Hawk) 2020 IQA at May 21 Strip

2020 Black Hawk Well Economics			Latest Estimate				
			Gross	Net @ MAY21 STRIP			
Well Name	LL	WI%	Well Cost $m	IRR%	NPV6 $m	CF Eff 1 YR (Spud)	CF Eff 3 YR (Spud)
MIGURA B - CASKEY B SA 1 1H	7,800	50%	7.0	86%	$4.1	$0.97	$2.15
MIGURA B - CASKEY B SA 2 2H	8,200	50%	6.2	70%	$3.0	$0.82	$2.04
MIGURA B - CASKEY B SA 5 5H	7,800	50%	7.3	0%	-$0.7	$0.59	$0.90
MIGURA B - CASKEY B SA 6 6H	7,800	50%	7.5	17%	$0.5	$0.55	$1.24
MIGURA B - LANIK A SA 1 1H	5,500	50%	5.8	108%	$3.6	$1.18	$2.39
MIGURA B - LANIK A SA 2 2H	5,700	50%	6.3	13%	$0.4	$0.51	$1.10
A WITTE A 2H	5,600	25%	6.7	56%	$0.8	$1.23	$1.59
A WITTE A 3H	6,100	25%	6.7	47%	$0.7	$1.18	$1.52
A WITTE A 4H	6,700	25%	7.5	88%	$1.5	$1.29	$1.85
CIACCIO A 4H	4,700	50%	5.6	51%	$1.2	$1.07	$1.59
CIACCIO A 5H	4,000	50%	5.3	108%	$2.8	$1.27	$2.19
CIACCIO A 6H	6,000	50%	5.9	61%	$1.5	$1.13	$1.72
LP-BUTLER A - JORDAN A SA 1 1H	5,800	50%	5.7	100%	$2.1	$1.40	$1.92
LP-BUTLER A 2H	5,200	50%	6.0	132%	$2.9	$1.60	$2.22
LP-BUTLER A 3H	5,200	50%	5.8	90%	$2.6	$1.22	$1.90
LP-BUTLER A 6H	5,200	50%	5.7	111%	$2.8	$1.47	$2.21
LP-BUTLER A 7H	5,200	50%	5.4	124%	$3.1	$1.48	$2.31
LP-BUTLER A 8H	5,200	50%	5.9	126%	$2.6	$1.37	$2.07
LP-BUTLER A 11H	5,200	50%	7.6	45%	$1.7	$1.11	$1.49
LP-BUTLER A 12H	5,500	50%	5.8	210%	$4.1	$2.00	$2.76
LP-BUTLER A 13H	4,600	50%	6.0	59%	$1.9	$1.13	$1.70
JORDAN A 3H	5,800	50%	5.6	89%	$2.2	$1.26	$1.98
JORDAN A 4H	5,800	50%	6.0	90%	$3.0	$1.03	$2.14
JORDAN B 3H	4,600	50%	5.0	131%	$2.8	$1.34	$2.39
JORDAN B 4H	4,600	50%	5.4	72%	$2.1	$0.76	$1.92
JORDAN A 6H	5,800	50%	5.8	140%	$3.3	$1.64	$2.44
JORDAN A 7H	5,800	50%	6.4	62%	$1.9	$0.94	$1.74
JORDAN B 6H	4,600	50%	5.6	60%	$1.8	$1.06	$1.73
JORDAN B 7H	4,600	50%	5.3	115%	$2.5	$1.12	$2.28
JORDAN A - JORDAN B SA 2 2H	8,600	50%	7.8	135%	$5.2	$0.92	$2.57
JORDAN A - JORDAN B SA 3 3H	8,600	50%	8.3	78%	$3.7	$0.56	$1.99
JORDAN A - JORDAN B SA 4 4H	8,700	50%	8.9	57%	$2.6	$0.91	$1.65
JORDAN A - JORDAN B SA 5 5H	8,700	50%	7.9	79%	$3.6	$0.93	$1.93
JORDAN A - JORDAN B SA 6 6H	8,700	50%	9.1	34%	$2.4	$0.62	$1.35
E BUTLER A AC 1H	5,800	50%	7.1	0%	-$2.2	$0.20	$0.29
E BUTLER A 12H	5,800	50%	6.2	45%	$1.1	$1.10	$1.52
E BUTLER A 13H	5,800	50%	6.2	5%	-$0.1	$0.49	$0.89
E BUTLER A 14H	5,800	50%	6.2	76%	$1.9	$1.30	$1.82
E BUTLER A 15H	5,800	50%	6.0	49%	$1.2	$1.09	$1.58
P WARZECHA A 10H	5,300	50%	5.7	36%	$0.8	$0.96	$1.38
SANDY A 10H	5,300	50%	5.4	39%	$1.0	$0.96	$1.42
SANDY A 11H	5,300	50%	5.5	16%	$0.3	$0.85	$1.17
SANDY A 9H	5,300	50%	5.6	47%	$1.2	$1.09	$1.53

2020 Black Hawk Well Economics			Latest Estimate				
			Gross	Net @ MAY21 STRIP			
Well Name	LL	WI%	Well Cost $m	IRR%	NPV6 $m	CF Eff 1 YR (Spud)	CF Eff 3 YR (Spud)
E BUTLER A 10H RF	5,800	50%	4.2	7%	$0.0	$0.02	$1.12
E BUTLER A 6H RF	5,800	50%	4.0	109%	$1.4	$0.01	$1.86
E BUTLER A 7H RF	5,800	50%	4.1	24%	$0.3	$0.01	$1.27
E BUTLER A 8H RF	5,800	50%	3.8	55%	$0.9	$0.01	$1.45
P WARZECHA A 8H RF	4,800	50%	4.1	13%	$0.2	$0.00	$1.02
P WARZECHA A 9H RF	4,800	50%	4.7	0%	-$0.6	$0.00	$0.70
SANDY A 7H RF	5,100	50%	3.0	39%	$0.4	$0.00	$1.44
SANDY A 8H RF	5,100	50%	3.7	0%	-$0.3	$0.00	$0.94
JORDAN A 1H RF	5,500	50%	3.2	135%	$1.6	$0.00	$2.13
JORDAN B 1H RF	5,600	50%	2.9	79%	$1.3	$0.00	$1.73
GALLO ROJO A AC 1H	5,200	98%	6.7	15%	$1.1	$0.33	$1.01
GALLO ROJO A AC 2H	5,200	98%	5.9	4%	-$0.2	$0.30	$0.83
A BANDUCH B AC 1H	6,158	100%	5.3	78%	$6.1	$1.08	$1.96
A BANDUCH B AC 2H	6,813	100%	5.8	47%	$4.3	$0.82	$1.55
A BANDUCH B AC 3H	7,065	100%	6.3	58%	$6.0	$1.00	$1.73
A BANDUCH C AC 1H	6,617	96%	6.0	27%	$2.3	$0.68	$1.28
A BANDUCH C AC 2H	6,414	96%	5.6	94%	$7.2	$1.25	$2.22
A BANDUCH C AC 3H	6,213	96%	5.1	27%	$2.0	$0.53	$1.24
DAVIS B AC 1H	6,500	100%	6.3	17%	$1.2	$0.59	$1.15
DAVIS B AC 2H	6,500	100%	6.7	0%	-$3.9	$0.16	$0.32
DAVIS B AC 3H	6,500	100%	6.2	19%	$1.5	$0.43	$1.15
GALLO ROJO A JOSEPH PSA 1H	5,600	33%	7.6	46%	$1.3	$1.06	$1.51
GALLO ROJO A 6H	5,200	98%	5.0	0%	-$1.1	$0.25	$0.75
GALLO ROJO A 7H	5,200	98%	4.6	29%	$1.7	$0.35	$1.26
GALLO ROJO A 8H	5,200	98%	4.7	49%	$3.8	$0.37	$1.56
A BANDUCH B 7H	6,717	100%	5.9	44%	$4.1	$0.76	$1.50
A BANDUCH B 9H	6,356	100%	5.3	47%	$3.8	$0.91	$1.58
A BANDUCH C 5H	6,588	96%	5.9	35%	$2.6	$0.84	$1.43
A BANDUCH C 7H	6,317	96%	5.4	63%	$4.6	$0.89	$1.76
A BANDUCH C 8H	6,185	96%	5.8	37%	$3.2	$0.59	$1.36
A BANDUCH C 9H	6,091	96%	5.3	117%	$8.5	$1.35	$2.54
DAVIS B 4H	6,500	100%	5.4	37%	$2.8	$0.50	$1.50
DAVIS B 5H	6,500	100%	5.3	0%	-$1.1	$0.26	$0.68
DAVIS B 6H	6,500	100%	4.8	0%	-$1.2	$0.31	$0.77
DAVIS B 7H	6,500	100%	4.9	47%	$3.4	$0.54	$1.66
LONESOME DOVE A 6H	6,150	89%	4.7	13%	$0.4	$0.73	$1.16
LONESOME DOVE A 7H	6,114	89%	4.7	27%	$1.5	$0.66	$1.35
LONESOME DOVE A 8H	6,130	89%	5.0	0%	-$0.8	$0.39	$0.81
LONESOME DOVE A 11H	6,500	89%	5.2	42%	$2.4	$0.96	$1.59
LONESOME DOVE A 10H	5,990	89%	5.0	0%	-$0.4	$0.54	$0.92
Black Hawk FY Program		65%	5.7	43%	$157.8	$0.79	$1.57

Eagle Ford (Hawkville) 2020 IQA at May 21 Strip

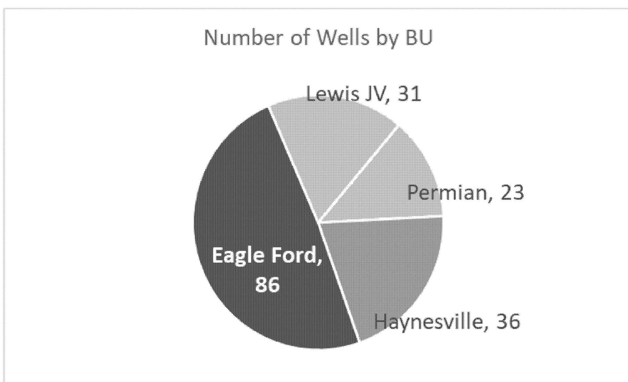
2020 Hawkville Well Economics			Latest Estimate				
			Gross	Net @ MAY21 STRIP			
Well Name	LL	WI%	Well Cost $m	IRR%	NPV6 $m	CF Eff 1 YR (Spud)	CF Eff 3 YR (Spud)
JC MARTIN 60H	9,500	90%	7.3	58%	$6.8	$0.97	$1.61
JC MARTIN 61H	9,900	90%	6.3	61%	$6.6	$0.99	$1.68
JC MARTIN 62H	10,000	90%	7.1	55%	$6.7	$0.87	$1.56
JC MARTIN 63H	9,700	90%	7.3	45%	$6.8	$0.82	$1.45
JC MARTIN 64H	9,500	90%	6.9	47%	$6.3	$0.89	$1.52
JC MARTIN 65H	9,400	90%	6.8	36%	$4.6	$0.78	$1.34
JC MARTIN 66H	8,700	90%	7.1	44%	$5.8	$0.79	$1.45
DONNELL A - DM 366 SA 1 1H	9,900	100%	7.4	16%	$1.3	$0.83	$1.12
DONNELL A - DM 366 SA 2 2H	6,996	100%	5.9	22%	$1.4	$0.87	$1.22
DONNELL A - DM 366 SA 3 3H	9,880	100%	6.7	0%	-$1.2	$0.51	$0.74
DONNELL A - DM 366 SA 4 4H	9,870	100%	6.6	0%	-$1.0	$0.57	$0.81
STS C 19H	9,700	100%	7.8	32%	$3.2	$0.88	$1.33
STS C 20H	9,500	100%	7.3	30%	$2.8	$0.88	$1.33
STS C 21H	9,900	100%	7.6	28%	$3.2	$0.76	$1.27
STS C 22H	10,500	100%	8.7	39%	$5.6	$0.75	$1.44
STS C 23H	10,500	100%	8.0	40%	$5.5	$0.76	$1.44
STS C 24H	10,500	100%	7.7	37%	$5.4	$0.72	$1.40
Hawkville FY Program		**96%**	**7.2**	**34%**	**$69.7**	**$0.80**	**$1.34**
FY Program		**70%**	**6.0**	**41%**	**$227.5**	**$0.79**	**$1.53**

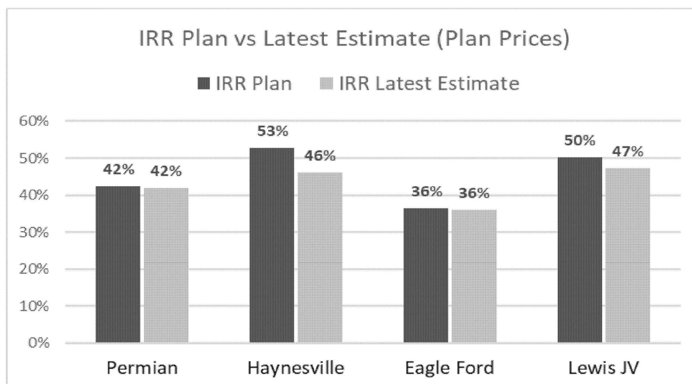
Lewis JV 2020 IQA at May 21 Strip Prices

2021 Lewis JV Economics			Latest Estimate				
			Gross	Net @ MAY21 Strip			
Well Name	WI%	LL (ft)	Well Cost $m	IRR%	NPV6 $m	CF Eff 1 YR (Spud)	CF Eff 3 YR (Spud)
Dora Martin 47H	32%	4,728	4.6	35%	$1.6	0.5	1.2
Dora Martin 48H	32%	4,807	5.1	25%	$1.3	0.4	1.0
Dora Martin 54H	32%	7,416	6.1	34%	$2.8	0.0	1.0
Dora Martin 55H	32%	7,534	6.2	44%	$4.0	0.0	1.2
Appling 23H	40%	6,003	5.4	77%	$5.2	0.7	1.9
Appling 24H	40%	6,212	5.5	73%	$5.0	0.6	1.8
WILLIE RANCH 18H	56%	4,791	4.2	44%	$3.4	0.4	1.3
WILLIE RANCH 19H	56%	4,912	4.7	40%	$3.3	0.4	1.3
WILLIE RANCH 20H	56%	5,293	4.1	49%	$3.6	0.5	1.5
WILLIE RANCH 21H	56%	5,193	4.5	42%	$3.3	0.4	1.3
Henderson Cenizo 9H	45%	7,113	6.6	24%	$2.4	0.0	0.7
Henderson Cenizo 12H	45%	7,670	5.7	31%	$2.6	0.0	1.0
Henderson Cenizo 13H	45%	7,606	6.0	29%	$2.5	0.0	1.0
FY Program			5.3	41%	$41.0	0.3	1.2

2021 IQA Summary

2021 New Well Economics	GFO1 Plan				Latest Estimate								
	Gross		Net @ 2021 ACB		Gross	Net @ 2021 ACB				Net @ May Strip Prices			
BU	Number of Wells	Well Cost $m/well	IRR %	NPV6 $m	Well Cost $m/well	IRR %	NPV6 $m	CF Eff 1 YR	CF Eff 3 YR	IRR %	NPV6 $m	CF Eff 1 YR	CF Eff 3 YR
Permian	23	8.6	42%	209	8.5	42%	192	0.5	1.3	77%	263	0.9	1.8
Haynesville	36	12.1	53%	224	10.8	46%	214	0.5	1.6	41%	170	0.5	1.4
Eagle Ford	86	5.7	36%	199	5.9	36%	202	0.5	1.6	71%	339	0.8	2.3
Lewis JV	31	5.4	50%	114	4.9	47%	95	0.6	1.5	44%	78	0.6	1.4





Permian 2021 IQA

2021 Permian New Well Economics			GFO1 Plan			Latest Estimate								
			Gross	Net @ 2021 ACB		Gross	Net @ 2021 ACB				Net @ May21 Strip			
Well Name	Lateral Length	WI %	Well Cost $m	IRR %	NPV6 $m	Well Cost $m	IRR %	NPV6 $m	CF Eff 1 YR (Spud)	CF Eff 3 YR (Spud)	IRR %	NPV6 $m	CF Eff 1 YR (Spud)	CF Eff 3 YR (Spud)
SHIRLEY 58-T2-13 W208H	5,000	100%	7.3	22%	3.7	7.6	12%	1.0	0.54	0.94	30%	2.5	0.96	1.18
STATE TIEMANN 56-T2-28 W208H	5,000	100%	6.6	12%	1.3	7.6	3%	-0.9	0.28	0.59	16%	1.5	0.53	0.98
STATE DOUG 56-T2-33X28 W203H	10,000	100%	12.1	16%	4.3	10.8	16%	3.7	0.36	0.86	40%	7.3	0.66	1.32
STATE DALTEXAS RANGER 56-T2-2X11 X103FH	7,500	100%	9.5	12%	2.3	8.6	19%	3.8	0.36	0.95	45%	7.2	0.60	1.41
STATE DALTEXAS RANGER 56-T2-2X11 W206FH	7,500	100%	9.6	12%	1.9	8.8	22%	4.2	0.29	1.03	55%	7.8	0.52	1.57
STATE MJ MCGARY 56-T2-32 W201H	5,000	100%	6.7	13%	1.5	6.7	20%	2.4	0.55	0.99	53%	4.8	0.92	1.46
STATE PONY 57-T2-16X9 W102H	10,000	100%	8.7	66%	15.0	8.2	70%	14.6	0.66	1.82	124%	18.9	1.09	2.50
STATE PONY 57-T2-16X9 W103H	10,000	100%	8.8	75%	15.1	8.3	71%	14.5	0.65	1.79	127%	18.8	1.08	2.46
STATE PONY 57-T2-16X9 W114H	10,000	100%	8.7	65%	14.9	8.2	69%	14.6	0.65	1.81	122%	18.8	1.09	2.48
STATE PONY 57-T2-16X9 W113H	10,000	100%	8.8	79%	15.1	8.2	74%	14.6	0.75	1.80	139%	18.9	1.20	2.47
STATE PONY 57-T2-16X9 W101H	10,000	100%	8.7	70%	15.0	8.8	63%	14.1	0.70	1.68	113%	18.4	1.13	2.31
STATE CUMBERLAND 57-T2-16X9 W111H	10,000	75%	8.7	74%	15.2	8.0	83%	11.1	0.86	1.89	158%	14.3	1.35	2.58
STATE PONY 57-T2-16X9 W115H	10,000	100%	8.7	68%	15.0	9.3	60%	13.7	0.74	1.62	109%	18.0	1.17	2.22
STATE PONY 57-T2-16X9 B202H	10,000	100%	8.6	107%	15.3	9.5	48%	9.5	0.73	1.42	99%	13.6	1.15	1.98
HS STATE 113-21X111-4 W107H	7,500	100%	10.7	29%	8.5	10.3	40%	10.2	0.58	1.28	68%	12.9	0.90	1.69
HS STATE 113-21X111-4 W108H	7,500	100%	10.5	31%	8.7	10.2	39%	10.3	0.53	1.27	67%	12.9	0.84	1.68
HS STATE 113-20X111-5 W108H	5,000	100%	8.4	22%	4.0	8.5	27%	4.9	0.57	1.11	51%	7.0	0.88	1.49
HS STATE 113-20X111-5 W107H	7,500	100%	8.4	23%	4.1	8.3	28%	5.0	0.58	1.13	54%	7.1	0.89	1.52
STATE ALLAR 57-T2-28 W203H	5,000	100%	6.8	27%	4.1	7.3	29%	4.9	0.54	1.12	53%	6.7	0.81	1.49
STATE ANNEX 57-T2-28 W206H	5,000	100%	6.9	26%	4.1	7.3	30%	4.9	0.58	1.14	57%	6.7	0.86	1.51
Permian CO 2021 ACB Year		**100%**	**176**	**40%**	**173**	**170**	**40%**	**161**	**0.57**	**1.32**	**76%**	**224**	**0.93**	**1.82**
ZUMA 57-T1-3X10 W102BO	10,000	50%	8.4	59%	12.1	8.2	68%	12.9	-	1.67	109%	16.3	-	2.56
ZUMA 57-T1-3X10 W101BO	10,000	50%	8.4	59%	12.1	8.1	52%	10.6	-	1.35	84%	13.3	-	2.08
ZUMA 57-T1-3X10 W101AP	10,000	50%	8.4	59%	12.1	8.4	38%	7.3	-	1.04	62%	9.5	-	1.64
Permian OBO 2021 ACB Year		**50%**	**25**	**59%**	**36**	**25**	**52%**	**31**	**-**	**1.35**	**85%**	**39**	**-**	**2.09**
Permian BU Total		**100%**	**8.6**	**42%**	**209**	**8.5**	**42%**	**192**	**0.53**	**1.32**	**77%**	**263**	**0.87**	**1.84**

Underperforming OBO investments

Main Drivers for Expected Improvement in Go-Forward Performance:

1. **CDP enhancement to costs and revenue**
2. High grading spend vs. obligation spend
3. Limited go-forward OBO
4. Pricing Improvement
5. Lateral Length
6. Frac Redesign (RTAN)

bpx energy

Haynesville (OBO) 2021 IQA

Underperforming OBO investments

2021 HSVL BU New Well Economics			GFO1 Plan			Latest Estimate								
			Gross	Net @ 2021 ACB		Gross	Net @ 2021 ACB				Net @ May21 Strip			
Well Name	Lateral Length	WI %	Well Cost $m	IRR %	NPV6 $m	Well Cost $m	IRR %	NPV6 $m	CF Eff 1 YR (Spud)	CF Eff 3 YR (Spud)	IRR %	NPV6 $m	CF Eff 1 YR (Spud)	CF Eff 3 YR (Spud)
Blackstone 34-3HC 1 Alt	7,500	4%	9.4	32%	0.3	8.5	81%	0.4	0.8	2.0	79%	0.4	0.8	2.0
Blackstone 34-3HC 2 Alt	7,500	4%	9.4	32%	0.3	9.7	65%	0.4	0.7	1.8	62%	0.3	0.7	1.7
McKissack 34-3HC 2 Alt	7,500	4%	8.8	50%	0.4	7.6	90%	0.4	0.8	2.2	88%	0.4	0.8	2.1
McKissack 34-3HC 3 Alt	7,500	4%	8.8	50%	0.4	7.9	87%	0.4	0.8	2.1	85%	0.4	0.8	2.1
McKissack 34-3HC 1 Alt	7,500	4%	8.8	50%	0.4	8.5	83%	0.4	0.8	2.0	81%	0.4	0.8	2.0
KELLEY 18&7-15-14HC 1	9,900	1%	10.1	53%	0.1	8.8	92%	0.1	1.1	2.0	90%	0.1	1.1	1.9
ADAMS 21-28-33HC 1-ALT	10,200	1%	11.0	61%	0.2	11.1	43%	0.2	0.2	1.4	37%	0.1	0.2	1.3
ADAMS 21-28-33HC 2-ALT	10,200	1%	11.0	61%	0.2	11.1	43%	0.1	0.2	1.4	37%	0.1	0.2	1.3
CURRY 28-33HC 1-ALT	9,600	2%	10.8	57%	0.2	11.0	40%	0.2	0.3	1.4	34%	0.1	0.3	1.3
CURRY 28-33HC 2-ALT	9,600	2%	10.8	57%	0.2	11.0	40%	0.2	0.3	1.4	34%	0.1	0.3	1.3
ROM 34&27&22-11-10HC 2-Alt	4,600	1%	11.8	49%	0.1	11.8	49%	0.1	0.4	1.5	44%	0.1	0.4	1.5
ROM 34&27&22-11-10HC 1-Alt	7,390	1%	11.6	51%	0.1	11.6	51%	0.1	0.4	1.5	46%	0.1	0.4	1.5
JH White 26-23-14HC 3-ALT	10,780		Not in GFO1			10.7	98%	1.5	0.5	2.5	90%	1.2	0.5	2.3
JH White 26-23-14HC 2-ALT	10,773		Not in GFO1			10.7	98%	1.5	0.5	2.5	90%	1.2	0.5	2.3
JH White 26-23-14HC 1-ALT	6,292		Not in GFO1			7.6	74%	0.8	0.4	2.1	66%	0.6	0.4	1.9
Doyle 14-23HC No. 1-Alt	9,971		Not in GFO1			10.0	99%	1.4	0.5	2.5	91%	1.1	0.5	2.3
Doyle 14-23-26HC No. 1-Alt	10,787		Not in GFO1			10.7	100%	1.5	0.5	2.6	92%	1.2	0.5	2.3
Doyle 14-23-26HC No. 2-Alt	10,794		Not in GFO1			10.7	100%	1.5	0.5	2.6	92%	1.2	0.5	2.3
PETTY HEIRS 2 HZ 3-ALT	4,600		Not in GFO1				300%	1.2			300%	1.1		
PETTY HEIRS 2 HZ 2-ALT	4,600		Not in GFO1				300%	1.2			300%	1.1		
JHSN 28&21-15-15 1HC	7,600		Not in GFO1				300%	0.7			300%	0.6		
JHSN 28&21-15-15 2HC	7,600		Not in GFO1				300%	0.7			300%	0.6		
JHSN 28&21-15-15 3HC	7,600		Not in GFO1				300%	0.7			300%	0.6		
EDWL 18-19-30HC 001-ALT	13,600		Not in GFO1			16.7	42%	0.2	0.7	1.4	33%	0.1	0.7	1.3
EDWL 18-19-30HC 002-ALT	12,765		Not in GFO1			16.1	39%	0.2	0.7	1.4	30%	0.1	0.7	1.3
APATO 1H	8,000		Not in GFO1			0.0	300%	0.1			300%	0.1		
BRACHI 1H	8,000		Not in GFO1			0.0	300%	0.0			300%	0.0		
Kinsey 27H 3-ALT	4,629		Not in GFO1			6.7	41%	0.0	0.3	1.4	31%	0.0	0.3	1.3
Kinsey 27H 2-ALT	4,629		Not in GFO1			7.2	36%	0.0	0.3	1.3	26%	0.0	0.3	1.2
Bayou Pierre 29-12-10 H 1-ALT	4,600		Not in GFO1			8.0	44%	0.6	0.5	1.5	34%	0.4	0.5	1.3
Bayou Pierre 29-12-10 H 2-ALT	4,600		Not in GFO1			8.0	44%	0.6	0.5	1.5	34%	0.4	0.5	1.3
DVS 17&20-15-14 HC 1-ALT	9,210		Not in GFO1			9.4	103%	0.0	1.0	2.1	94%	0.0	1.0	2.0
DVS 17&20-15-14 HC 2-ALT	8,764		Not in GFO1			8.7	107%	0.0	1.0	2.2	98%	0.0	1.0	2.0
PORTER 23&14-12-13 1HC	7,500		Not in GFO1			10.1	55%	0.5	0.6	1.6	44%	0.4	0.5	1.4
PORTER 23&14-12-13 2HC	9,800		Not in GFO1			10.1	55%	0.5	0.6	1.6	44%	0.4	0.5	1.4
PORTER 23&14-12-13 3HC	9,800		Not in GFO1			10.1	55%	0.5	0.6	1.6	44%	0.4	0.5	1.4
OBO FY LE			**10.2**	**45%**	**2.7**	**9.4**	**100%**	**18.7**	**0.7**	**2.4**	**93%**	**15.5**	**0.7**	**2.2**

Haynesville (Company Operated) 2021 IQA

2021 HSVL BU New Well Economics			GFO1 Plan			Latest Estimate								
			Gross	Net @ 2021 ACB		Gross	Net @ 2021 ACB				Net @ May21 Strip			
Well Name	Lateral Length	WI %	Well Cost $m	IRR %	NPV6 $m	Well Cost $m	IRR %	NPV6 $m	CF Eff 1 YR (Spud)	CF Eff 3 YR (Spud)	IRR %	NPV6 $m	CF Eff 1 YR (Spud)	CF Eff 3 YR (Spud)
GANYMEDE 1H	13,000	100%	19.8	46%	27.8	17.3	50%	28.2	0.0	1.5	48%	24.3	0.0	1.5
GANYMEDE 1HB	12,000	100%	17.9	38%	22.3	20.1	29%	19.3	0.0	1.0	27%	15.7	0.0	1.0
RHEA 1H	13,000	100%	15.9	53%	25.9	17.4	47%	24.2	0.0	1.3	45%	20.6	0.0	1.3
RHEA 1HB	10,000	100%	17.0	32%	15.8	18.8	0%	-7.2	0.0	0.3	0%	-8.0	0.0	0.3
RHEA 2HU	10,000	100%	17.6	48%	20.0	21.4	25%	12.3	0.0	0.8	22%	9.4	0.0	0.8
Pluto 3HB	6,900	50%	12.1	54%	5.8	Removed from Schedule								
YOUNG 26-35 #1-ALT	7,360	50%	9.2	72%	5.7	8.8	96%	6.5	1.1	2.0	93%	5.7	1.1	1.9
YOUNG 26-35 #2-ALT	7,360	50%	9.2	72%	5.7	9.4	80%	6.2	1.0	1.8	73%	5.1	1.0	1.7
SAMPLE 5-32 #3-ALT	9,900	100%	11.4	71%	14.2	11.7	66%	12.9	0.7	1.7	59%	10.2	0.7	1.6
M&M 39-27HC 1-ALT	9,900	73%	11.5	97%	11.9	10.4	108%	14.1	0.8	2.4	96%	11.4	0.8	2.2
M&M 39-27HC 2-ALT	9,900	Not in GFO1				10.2	109%	14.0	0.9	2.4	97%	11.3	0.8	2.2
MARTIN #2-ALT	9,900	94%	10.6	72%	12.6	11.0	63%	10.0	0.6	1.8	52%	7.6	0.6	1.6
MARTIN #3-ALT	9,900	91%	10.9	72%	12.9	11.4	61%	10.5	0.6	1.7	49%	7.9	0.6	1.6
GARLAND 5-8-17 #1	15,200	79%	14.6	94%	20.5	14.6	89%	16.6	0.7	2.4	74%	12.9	0.7	2.1
BURNS FOREST 24-25 HC 1-ALT	9,900	59%	12.1	74%	9.0	12.1	66%	9.9	0.9	1.7	58%	7.8	0.9	1.6
J.P. HOLLEY 8-17HC 1-ALT	9,900	Not in GFO1				12.8	55%	6.1	0.9	1.6	43%	4.4	0.8	1.4
GLASSCOCK 34-27 #1	9,900	Not in GFO1				12.0	83%	11.9	1.0	1.9	60%	7.8	0.8	1.6
SNYDER 23-14 #1	9,900	66%	11.5	88%	10.9	Removed from Schedule								
Coop FY LE			**13.4**	**53%**	**221.2**	**13.7**	**44%**	**195.5**	**0.5**	**1.5**	**40%**	**154.3**	**0.4**	**1.4**
HSVL BU FY LE			**12.1**	**53%**	**223.9**	**10.8**	**46%**	**214.3**	**0.5**	**1.6**	**41%**	**169.8**	**0.5**	**1.4**

5 East Texas Wells. All others are Louisiana

Main Drivers for Expected Improvement in Go-Forward Performance:

1. **De-risking delivery; Funding shift from TX to LaHa**
2. Frac Redesign (RTAN)
3. Enhanced production strategy (Auto PI)
4. Well bore design cash acceleration

Eagle Ford (Black Hawk) 2021 IQA 1 of 2

2021 Black Hawk Well Economics		GFO1 Plan				Latest Estimate								
		Gross		Net @ 2021 ACB		Gross	Net @ 2021 ACB				Net @ MAY21 STRIP			
Well Name	WI%	LL (ft)	Well Cost $m	IRR%	NPV6 $m	Well Cost $m	IRR%	NPV6 $m	CF Eff 1 YR (Spud)	CF Eff 3 YR (Spud)	IRR%	NPV6 $m	CF Eff 1 YR (Spud)	CF Eff 3 YR (Spud)
CROW A 4H	39%	3,951	5.03	15%	$0.4	5.13	13.8%	$0.3	$0.00	$1.05	50%	$1.4	$0.00	$1.76
CROW A 5H	39%	4,345	5.26	20%	$0.6	5.15	19.1%	$0.5	$0.00	$1.14	59%	$1.6	$0.00	$1.90
CROW A 6H	39%	4,476	5.36	18%	$0.5	5.23	18.2%	$0.5	$0.00	$1.13	59%	$1.6	$0.00	$1.90
CROW A 7H	39%	4,668	5.08	23%	$0.6	4.95	24.8%	$0.6	$0.00	$1.22	76%	$1.8	$0.00	$2.05
CROW A 8H	39%	3,769	4.90	18%	$0.4	4.89	14.1%	$0.3	$0.00	$0.94	43%	$1.2	$0.00	$1.52
CROW A 9H	39%	4,104	5.27	14%	$0.3	5.13	16.4%	$0.3	$0.00	$1.12	64%	$1.5	$0.00	$1.90
CROW A 10H	39%	4,099	4.53	21%	$0.5	4.28	23.9%	$0.6	$0.00	$1.20	51%	$1.3	$0.00	$1.77
CROW A 11H	39%	4,388	4.62	24%	$0.7	4.41	29.5%	$0.8	$0.00	$1.34	77%	$1.9	$0.00	$2.25
CROW A 12H	39%	4,428	4.78	24%	$0.7	4.47	29.0%	$0.8	$0.00	$1.33	75%	$1.9	$0.00	$2.22
CROW A 13H	39%	4,908	4.96	27%	$0.8	4.55	32.7%	$0.9	$0.00	$1.36	79%	$2.1	$0.00	$2.25
CROW A 14H	39%	4,775	5.06	30%	$1.0	4.82	30.3%	$1.0	$0.00	$1.30	70%	$2.2	$0.00	$2.14
CROW A AC 2H	39%	4,623	4.68	5%	($0.0)	4.62	5.4%	($0.0)	$0.00	$0.84	32%	$0.8	$0.00	$1.42
CROW A 15H	39%	5,275	5.21	9%	$0.1	5.42	27.8%	$0.9	$0.00	$1.29	69%	$2.3	$0.00	$2.11
CROW A 16H	39%	5,608	5.37	31%	$1.1	5.35	31.2%	$1.1	$0.00	$1.37	70%	$2.5	$0.00	$2.22
CROW A 17H	39%	5,407	5.61	29%	$1.1	5.73	32.3%	$1.3	$0.00	$1.37	71%	$2.8	$0.00	$2.24
CROW A 18H	39%	6,109	5.43	35%	$1.2	5.39	47.0%	$1.9	$0.00	$1.65	96%	$3.5	$0.00	$2.68
CROW A 19H	39%	5,154	5.16	32%	$1.1	5.35	34.2%	$1.3	$0.00	$1.40	74%	$2.7	$0.00	$2.28
CROW A 20H	39%	4,950	5.03	32%	$1.0	5.10	35.6%	$1.2	$0.00	$1.41	78%	$2.6	$0.00	$2.30
GUEVARA B 5H	50%	6,794	7.08	24%	$1.5	7.33	11.8%	$0.4	$0.00	$0.96	37%	$2.0	$0.00	$1.51
GUEVARA B 6H	50%	6,623	6.42	21%	$1.1	6.75	12.6%	$0.4	$0.00	$0.96	41%	$1.8	$0.00	$1.52
GUEVARA B 4H	50%	6,193	6.67	18%	$0.9	7.28	7.3%	$0.1	$0.00	$0.87	29%	$1.4	$0.00	$1.37
GUEVARA B AC 1H	50%	6,145	6.22	5%	($0.1)	6.72	12.2%	$0.5	$0.00	$0.90	33%	$1.7	$0.00	$1.39
S WITTE A 2H	38%	8,360	7.87	26%	$1.1	8.13	24.2%	$1.0	$0.71	$1.24	68%	$2.3	$1.16	$1.79
CIACCIO A 7H	50%	6,452	5.90	53%	$2.0	6.21	45.2%	$1.8	$0.75	$1.54	111%	$3.4	$1.27	$2.23
CKODRE A 7H	50%	5,383	5.56	36%	$1.3	5.28	32.0%	$1.0	$0.80	$1.36	91%	$2.2	$1.30	$1.98
CKODRE A 8H	50%	5,652	5.70	39%	$1.4	5.24	42.8%	$1.3	$0.88	$1.50	113%	$2.6	$1.44	$2.18
CKODRE A 9H	50%	5,913	5.68	46%	$1.6	5.68	38.0%	$1.4	$0.72	$1.45	94%	$2.8	$1.22	$2.11
CKODRE A 10H	50%	6,151	5.76	48%	$1.8	5.64	45.2%	$1.7	$0.77	$1.55	110%	$3.1	$1.30	$2.26
CKODRE A 11H	50%	6,358	5.84	52%	$1.9	5.74	50.9%	$1.9	$0.79	$1.62	125%	$3.5	$1.34	$2.36
CKODRE A-W. BUTLER A SA 1 1H	40%	5,356	5.56	35%	$1.0	5.16	33.6%	$0.8	$0.81	$1.37	96%	$1.7	$1.31	$1.99
MUELLER 18A-FRISBIE B SA 1 1H	47%	6,929	6.00	62%	$2.0	6.12	64.6%	$2.2	$0.99	$1.82	125%	$3.5	$1.44	$2.43
P. FRISBIE A - B SA 1 1H	50%	7,009	5.12	37%	$1.1	5.21	44.9%	$1.4	$0.85	$1.56	92%	$2.4	$1.24	$2.09
P. FRISBIE A - B SA 2 2H	49%	7,302	5.63	47%	$1.5	5.73	49.1%	$1.7	$0.90	$1.65	98%	$2.9	$1.31	$2.22
P. FRISBIE A 2H	50%	7,495	5.72	65%	$2.2	6.33	51.7%	$2.0	$0.97	$1.66	107%	$3.2	$1.41	$2.22
P. FRISBIE A 3H	50%	7,899	5.93	64%	$2.2	6.20	66.3%	$2.5	$1.09	$1.87	128%	$3.9	$1.58	$2.50
P. FRISBIE A 4H	50%	4,997	6.10	62%	$2.2	6.12	72.0%	$2.7	$1.15	$1.95	140%	$4.2	$1.66	$2.61
P. FRISBIE A 5H	50%	5,880	6.26	78%	$2.8	6.16	82.3%	$3.0	$1.20	$2.04	161%	$4.5	$1.73	$2.73

Eagle Ford (Black Hawk) 2021 IQA 2 of 2

2021 Black Hawk Well Economics		GFO1 Plan				Latest Estimate								
		Gross		Net @ 2021 ACB		Gross	Net @ 2021 ACB				Net @ MAY21 STRIP			
Well Name	WI%	LL (ft)	Well Cost $m	IRR%	NPV6 $m	Well Cost $m	IRR%	NPV6 $m	CF Eff 1 YR (Spud)	CF Eff 3 YR (Spud)	IRR%	NPV6 $m	CF Eff 1 YR (Spud)	CF Eff 3 YR (Spud)
PEEBLES A 4H	50%	5,702	5.66	36%	$1.1	5.79	32.0%	$1.1	$0.73	$1.39	94%	$2.7	$1.31	$2.11
PEEBLES A 5H	50%	5,897	5.89	35%	$1.1	7.01	18.5%	$0.7	$0.62	$1.19	63%	$2.3	$1.12	$1.81
PEEBLES A 6H	50%	6,100	5.97	38%	$1.2	5.77	9.6%	$0.2	$0.54	$1.04	44%	$1.3	$0.98	$1.58
PEEBLES A 9H	50%	6,203	6.04	37%	$1.3	7.66	23.8%	$1.1	$0.66	$1.26	76%	$2.9	$1.19	$1.92
ULRICH A - WILLIAMS A SA 1 1H	50%	6,255	5.77	57%	$1.8	7.24	29.1%	$1.3	$0.63	$1.33	84%	$3.0	$1.11	$1.97
ULRICH A 3H	50%	6,233	5.85	53%	$1.8	6.04	45.9%	$1.8	$0.76	$1.62	111%	$3.5	$1.35	$2.39
ULRICH A 4H	50%	5,956	5.85	55%	$1.8	5.92	48.9%	$1.9	$0.78	$1.65	121%	$3.6	$1.37	$2.43
ULRICH A 5H	50%	5,582	5.67	52%	$1.7	7.34	27.0%	$1.3	$0.63	$1.33	74%	$3.0	$1.11	$1.96
ULRICH A 6H	50%	6,081	5.37	50%	$1.5	5.61	55.5%	$1.8	$0.79	$1.68	141%	$3.5	$1.40	$2.48
ULRICH A 7H	50%	6,169	5.76	55%	$1.7	5.62	56.3%	$1.8	$0.79	$1.68	144%	$3.5	$1.40	$2.48
LANIK A - LANIK B SA 2 2H WORKOVER	50%					0.4	300%	$1.9	$6.19	$11.86	300%	$2.6	$10.18	$17.48
CASKEY A 7H WORKOVER	50%					0.3	300%	$0.5	$4.21	$5.57	300%	$0.8	$7.10	$8.78
GUEVARA B 1H RF		5,960	3.78	113%	$2.1									
CEF-CREWS B AC SA 1 1H	78%	6,334	6.08	27%	$2.7	5.64	34.2%	$3.1	$0.00	$1.26	65%	$5.2	$0.00	$1.89
CEF-CREWS B AC SA 2 2H	78%	4,844	5.32	25%	$1.8	5.41	25.6%	$1.7	$0.00	$1.20	58%	$3.8	$0.00	$1.84
CEF-CREWS B SA 1 1H	78%	5,040	5.27	3%	($0.2)	5.59	0.0%	($0.4)	$0.00	$0.81	22%	$1.0	$0.00	$1.25
CREWS A AC-CRISP A AC SA 1 1H	78%	7,701	6.27	39%	$4.3	6.82	35.7%	$4.0	$0.00	$1.29	65%	$6.5	$0.00	$1.90
CEF-CRISP A SA 1 1H	78%	7,844	6.22	36%	$2.6	6.61	33.1%	$2.4	$0.00	$1.36	74%	$5.2	$0.00	$2.06
CRISP A AC-CREWS A AC SA 1 1H	78%	8,353	7.01	47%	$5.1	7.33	42.6%	$4.9	$0.00	$1.53	77%	$8.3	$0.00	$2.31
CRISP A-CREWS A SA 1 1H	78%	8,247	6.94	17%	$1.1	7.28	14.2%	$0.9	$0.00	$1.03	40%	$3.3	$0.00	$1.56
CRISP B AC-CREWS A AC SA 1 1H	78%	10,005	7.57	45%	$6.3	7.86	42.1%	$6.1	$0.00	$1.42	72%	$9.4	$0.00	$2.10
CRISP B AC-CREWS A AC SA 2 2H	78%	9,391	7.18	44%	$5.8	7.43	41.9%	$5.6	$0.00	$1.41	72%	$8.7	$0.00	$2.09
CRISP B AC-CREWS A AC SA 3 3H	78%	6,858	5.94	33%	$3.5	6.00	37.7%	$3.5	$0.00	$1.28	71%	$5.8	$0.00	$1.93
YANTA A AC-CREWS B AC SA 3 3H	78%	7,642	5.94	51%	$4.9	6.30	55.3%	$4.7	$0.00	$1.64	109%	$8.0	$0.00	$2.50
CRISP B-CREWS A SA 1 1H	78%	9,542	7.15	25%	$2.0	7.62	20.7%	$1.7	$0.00	$1.14	50%	$4.4	$0.00	$1.72
CRISP B-CREWS A SA 2 2H	78%	6,643	5.92	12%	$0.5	6.86	5.9%	($0.0)	$0.00	$0.88	33%	$1.9	$0.00	$1.35
YANTA A AC-CREWS B AC SA 1 1H	78%	7,848	5.99	53%	$5.1	6.21	59.3%	$5.0	$0.00	$1.71	115%	$8.4	$0.00	$2.61
YANTA A AC-CREWS B AC SA 2 2H	78%	7,329	6.31	44%	$4.2	6.14	49.3%	$4.4	$0.00	$1.61	97%	$7.5	$0.00	$2.46
YANTA A AC-CRISP A AC SA 1 1H	78%	6,553	5.66	44%	$3.7	6.33	38.7%	$3.3	$0.00	$1.41	75%	$6.0	$0.00	$2.12
YANTA A-BODDEN UNIT SA 1 1H	78%	4,726	5.41	9%	$0.2	5.97	4.4%	($0.1)	$0.00	$0.90	28%	$1.5	$0.00	$1.36
YANTA A-CREWS B SA 1 1H	78%	7,827	6.77	14%	$0.9	6.89	14.6%	$0.8	$0.00	$1.04	43%	$3.1	$0.00	$1.59
YANTA A-CREWS B SA 2 2H	78%	6,526	5.89	12%	$0.5	5.76	13.5%	$0.6	$0.00	$1.03	43%	$2.5	$0.00	$1.58
DAVIS A 4H	100%	5,671	4.85	55%	$3.7	4.59	60.1%	$3.9	$1.00	$1.85	114%	$6.2	$1.49	$2.51
DAVIS A 5H	100%	5,445	4.73	55%	$3.6	4.62	55.9%	$3.7	$0.89	$1.77	108%	$5.9	$1.34	$2.41
DAVIS A 6H	100%	5,520	4.73	51%	$3.3	4.62	52.1%	$3.4	$0.87	$1.72	102%	$5.6	$1.31	$2.35
DAVIS A 7H	100%	5,650	4.73	58%	$3.7	4.62	57.2%	$3.7	$0.90	$1.79	110%	$6.0	$1.36	$2.44
DAVIS A 8H	100%	5,543	4.73	64%	$4.0	4.59	63.5%	$4.1	$0.95	$1.88	120%	$6.5	$1.42	$2.56
MIKA A 4H	100%	5,380	4.67	59%	$3.8	4.93	50.3%	$3.7	$0.87	$1.72	98%	$6.0	$1.30	$2.34
MIKA A 5H	100%	5,356	4.67	50%	$3.2	4.96	43.8%	$3.0	$0.79	$1.57	87%	$5.1	$1.20	$2.14
MIKA A 7H	100%	5,543	4.67	57%	$3.6	4.96	48.1%	$3.4	$0.83	$1.65	95%	$5.6	$1.25	$2.25
MIKA A 8H	100%	5,485	4.74	64%	$4.1	5.01	54.5%	$3.9	$0.88	$1.75	106%	$6.3	$1.32	$2.38
MIKA A 6H		5,622	4.74	54%	$3.4									
Black Hawk FY Program			5.7		144.7	5.7	0.3	142.6	0.5	1.6	0.7	275.3	0.8	2.4

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Eagle Ford (Hawkville) 2021

2021 Hawkville Well Economics		GFO1 Plan				Latest Estimate								
		Gross		Net @ 2021 ACB		Gross	Net @ 2021 ACB				Net @ MAY21 STRIP			
Well Name	WI%	LL (ft)	Well Cost $m	IRR%	NPV6 $m	Well Cost $m	IRR%	NPV6 $m	CF Eff 1 YR (Spud)	CF Eff 3 YR (Spud)	IRR%	NPV6 $m	CF Eff 1 YR (Spud)	CF Eff 3 YR (Spud)
JC MARTIN 80H	90%	7,200	6.0	42%	$6.4	5.96	44.4%	$6.7	$0.45	$1.52	57%	$6.7	$0.73	$1.76
JC MARTIN 81H	90%	7,200	5.8	44%	$7.6	6.19	41.2%	$6.5	$0.44	$1.46	51%	$6.5	$0.70	$1.70
JC MARTIN 82H	90%	7,200	5.8	43%	$7.7	6.23	45.8%	$7.2	$0.46	$1.53	60%	$7.1	$0.73	$1.78
JC MARTIN 83H	90%	7,200	5.8	43%	$7.7	6.65	35.4%	$6.1	$0.40	$1.35	45%	$6.0	$0.65	$1.57
JC MARTIN 84H	90%	7,200	5.8	42%	$7.7	7.03	40.1%	$7.3	$0.43	$1.44	49%	$7.3	$0.69	$1.68
JC MARTIN 85H	90%	7,200	5.8	42%	$7.7	6.91	37.2%	$6.7	$0.41	$1.38	46%	$6.6	$0.66	$1.61
LOWE 35H	90%	9,749	7.5	18%	$1.9	7.86	45.2%	$7.4	$0.60	$1.54	70%	$8.8	$0.90	$1.92
LOWE 36H	100%	9,744	7.5	18%	$1.9	8.03	34.2%	$6.1	$0.52	$1.32	53%	$7.6	$0.78	$1.65
WK BD GU 2-PEEBLES 2 SA 1 1H	87%					9.08	30.2%	$5.6	$0.63	$1.26	45%	$6.5	$0.85	$1.50
STOREY UNIT 1 7H		5,000	5.7	32%	$0.9									
Hawkville FY Program			$6.3		$48.6	$7.1	$0.4	$59.5	$0.5	$1.4	$0.5	$63.2	$0.7	$1.7
FY Program			5.7	36%	$199	5.9	36%	$202	$0.5	$1.6	71%	$338.5	$0.8	$2.3

Main Drivers for Expected Improvement in Go-Forward Performance:

1. **Better reservoir characterization**
2. Frac Re-design (RTAN)
3. Pricing Improvement
4. Consistency and accuracy in estimates

Lewis JV 2021 IQA

2021 Lewis JV Economics		GFO1 Plan				Latest Estimate								
		Gross		Net @ 2021 ACB		Gross	Net @ 2021 ACB				Net @ MAY21 Strip			
Well Name	WI%	LL (ft)	Well Cost $m	IRR%	NPV6 $m	Well Cost $m	IRR%	NPV6 $m	CF Eff 1 YR (Spud)	CF Eff 3 YR (Spud)	IRR%	NPV6 $m	CF Eff 1 YR (Spud)	CF Eff 3 YR (Spud)
Hamilton No. 25H	50%	7,600	6.2	25%	$3.8	5.8	23%	$3.5	0.0	0.0	21%	$2.7	0.0	0.0
Hamilton No. 26H	50%	8,000	6.4	24%	$3.8	7.0	16%	$2.7	0.0	0.0	14%	$1.9	0.0	0.0
LC Wright PSA E No. 9H	5%	7,480	5.2	76%	$0.5	5.2	65%	$0.4	0.6	1.6	58%	$0.3	0.6	1.5
LC Wright PSA E No. 10H	1%	7,015	5.2	69%	$0.2	4.7	75%	$0.1	0.8	1.9	70%	$0.1	0.8	1.7
PALAFOX STATE PSA B NO.100H	45%	6,000	4.9	49%	$3.1	4.2	69%	$3.2	0.8	1.7	63%	$2.5	0.8	1.6
PALAFOX STATE PSA D NO.101H	45%	6,000	4.7	52%	$3.2	4.0	78%	$3.3	0.8	1.8	72%	$2.6	0.8	1.7
PALAFOX STATE PSA B NO.500H	45%	6,000	4.7	45%	$3.0	4.2	54%	$3.0	0.6	1.5	47%	$2.3	0.6	1.4
PALAFOX STATE PSA D NO.501H	45%	6,000	4.7	47%	$3.1	4.7	46%	$2.9	0.5	1.4	41%	$2.2	0.5	1.3
Appling PSA C No. 26H	40%	6,113	6.2	57%	$6.7	5.8	70%	$6.0	0.7	1.9	71%	$5.2	0.7	1.9
Appling PSA D No. 27H	40%	6,517	6.0	63%	$6.8	5.4	78%	$6.2	0.7	2.0	81%	$5.4	0.8	2.0
Appling PSA E No. 28H	40%	7,000	6.6	63%	$7.9	6.3	77%	$7.1	0.7	1.9	80%	$6.1	0.8	2.0
Appling PSA F No. 29H	40%	7,000	5.4	61%	$5.6	5.1	74%	$5.0	0.7	1.9	77%	$4.4	0.8	1.9
Owen-Briscoe-Manry GU L No. 53H	50%	8,000	5.6	64%	$3.2	6.5	32%	$3.1	0.4	1.2	25%	$2.2	0.4	1.1
Owen-Briscoe-Manry GU M No. 54H	50%	8,000	5.6	64%	$3.2	4.9	56%	$3.8	0.4	1.5	46%	$2.8	0.4	1.4
Owen-Briscoe-Manry GU N No. 55H	50%	8,000	5.6	64%	$3.2	5.0	56%	$3.8	0.4	1.5	46%	$2.8	0.4	1.4
Owen-Briscoe-Manry GU O No. 56H	48%	8,000	5.6	64%	$3.2	5.1	55%	$3.6	0.4	1.5	45%	$2.6	0.4	1.3
Dawson 1352 No. 1H	38%	7,149	5.0	64%	$3.3	3.8	80%	$3.0	0.7	2.0	89%	$2.8	0.8	2.0
Dawson 1352 No. 2H	38%	6,355	4.6	61%	$2.7	4.0	72%	$3.0	0.7	1.9	79%	$2.7	0.8	2.0
Dawson 1352 No. 3H	38%	5,833	4.3	69%	$2.6	3.9	71%	$3.0	0.7	1.9	76%	$2.7	0.8	2.0
Dawson 1352 No. 500H	38%	7,149	5.0	64%	$3.3	3.7	83%	$3.0	0.7	2.0	93%	$2.8	0.9	2.1
Dawson 1352 No. 501H	38%	6,575	4.7	69%	$3.2	4.1	69%	$2.9	0.7	1.8	74%	$2.7	0.8	1.9
Dawson 1352 No. 502H	38%	6,119	4.4	71%	$2.8	4.0	70%	$3.0	0.7	1.9	75%	$2.7	0.8	2.0
Owen 1080 GU G No. 31H	45%	8,000	5.6	63%	$2.8	5.2	49%	$3.2	0.6	1.5	42%	$2.4	0.6	1.4
Owen 1080 GU H No. 32H	45%	8,000	5.6	65%	$2.8	5.5	50%	$3.2	0.6	1.5	42%	$2.3	0.6	1.3
Owen 1080 GU I No. 33H	45%	7,064	5.6	59%	$2.4	5.3	54%	$3.3	0.6	1.5	45%	$2.5	0.6	1.4
Owen 1080 GU J No. 34H	45%	8,000	5.6	63%	$2.8	5.3	55%	$3.4	0.6	1.5	46%	$2.5	0.6	1.4
Owen 1080 GU K No. 35H	45%	8,000	5.0	62%	$2.8	5.3	49%	$3.3	0.6	1.5	42%	$2.5	0.6	1.4
Craft 3H	56%					4.3	60%	$3.8	0.7	1.6	57%	$3.1	0.8	1.6
Craft 4H	56%					4.4	57%	$3.7	0.7	1.6	53%	$3.0	0.8	1.5
Schubert No. 8H	56%					3.8	52%	$2.9	0.7	1.5	49%	$2.3	0.7	1.4
STS A 5H	56%	Not in GFO1 Plan				5.8	22%	$1.6	0.5	1.0	15%	$0.8	0.4	0.9
Heim No. 7H	56%					4.2	58%	$3.6	0.7	1.6	52%	$2.9	0.7	1.5
Dora Martin 56H	50%					4.8	73%	$4.5	0.8	1.8	70%	$3.8	0.8	1.7
Gates 11-DR No. 1002H	34%					5.5	44%	$1.7	0.6	1.3	56%	$1.9	0.7	1.5
FY Program			5.4	50%	$114.4	4.9	47%	$94.7	0.6	1.47	44%	$78.1	0.6	1.4

Underperforming OBO investments

Appendix

Comps for Recent US Unconventional Gas Transactions**

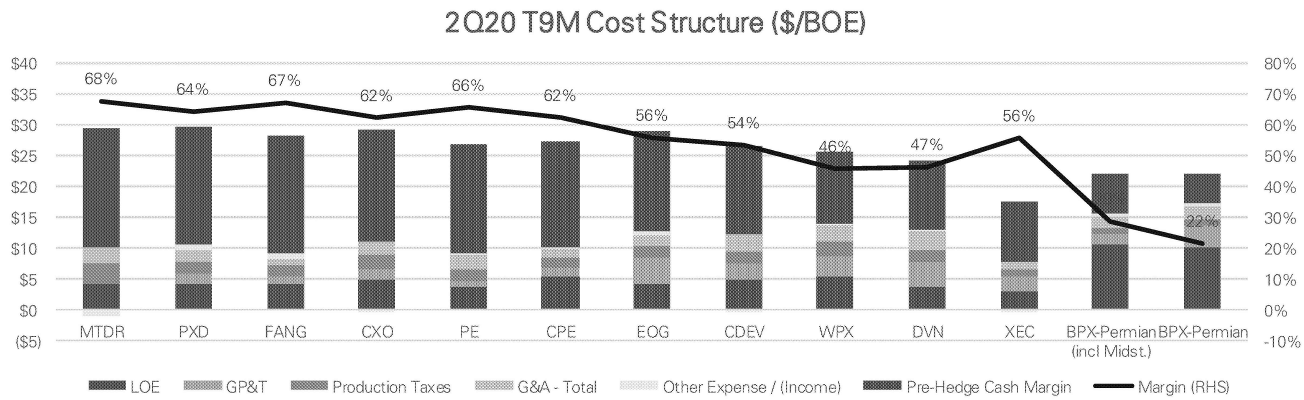
Date Announced	US Play	Buyers	Sellers	Value ($MM)	$/Acre	$/Daily BOE	Counties
2/3/2021	Marcellus	Northern Oil & Gas Inc, Arch Energy Partners, EQT	Reliance Energy Inc	250		7,500	Allegheny, Armstrong, Cambria, Fayette, Greene, Indiana, Washington, Westmoreland
10/27/2020	Marcellus	EQT	Chevron	735		8,467	Allegheny, Armstrong, Butler, Cambria, Carroll, Clarion, Clearfield, Columbiana, Coshocton, Crawford, Elk, Erie, Fayette, Greene, Guernsey, Holmes, Indiana, Lawrence, Mahoning, Marshall, McKean, Medina, Mercer, Monroe, Morgan, Muskingum, Noble, Ohio, Portage, Stark, Summit, Trumbull, Tuscarawas, Venango, Warren, Washington, Wayne, Westmoreland, Wetzel
9/30/2020	Marcellus	Tilden Marcellus LLC	EOG Resources	130	3030	9,000	Bradford
5/11/2020	Marcellus	Diversified Gas & Oil Plc	EQT	125		13,889	Cameron, Clarion, Clearfield, Doddridge, Elk, Harrison, Indiana, Jefferson, Marion, Monongalia, Ritchie, Taylor, Tioga, Tyler
5/4/2020	Utica	National Fuel Gas	Shell	541		7,500	Allegheny, Armstrong, Bradford, Cameron, Centre, Chemung, Clarion, Clearfield, Elk, Forest, Greene, Indiana, Jefferson, McKean, Steuben, Tioga, Venango, Warren, Washington, Westmoreland
1/24/2020	Marcellus	KeyBank	EdgeMarc Energy Holdings LLC	90		6,207	Armstrong, Butler
7/29/2019	Haynesville	Osaka Gas	Sabine Oil & Gas	610	2059	13,500	Angelina, Cherokee, Gregg, Harrison, Leon, Marion, Panola, Rusk, Smith, Upshur, Wood
7/24/2019	Utica	Diversified Gas & Oil Plc	EdgeMarc Energy Holdings LLC	50		4,615	Monroe, Washington
7/2/2019	Haynesville	Shelby O&G Co	Weatherly Oil & Gas LLC	26	608	13,500	Nacogdoches, Sabine, San Augustine, Shelby
3/27/2019	Marcellus	Diversified Gas & Oil Plc	HG Energy LLC	400		19,364	Barbour, Gilmer, Monongalia, Preston, Upshur, Washington
11/19/2018	Haynesville	Aethon Energy Management LLC	QEP Resources	735	1343	13,500	Bienville, Bossier, Caddo, De Soto, Red River, Sabine
7/18/2018	Haynesville	Comstock Resources	Enduro Resource Partners LLC	31		7,159	Bossier, Caddo, De Soto
6/29/2018	Utica	Ascent Resources Utica LLC	CNX Resources, Hess, Utica Minerals Development LLC, Salt Fork Resources LLC	1500	7274	15,950	Belmont
6/29/2018	Haynesville	Osaka Gas	Sabine Oil & Gas	146	1793	15,000	Gregg, Harrison, Panola
3/14/2018	Marcellus	XPR Resources	Rex Energy Corp	17.2		12,555	Centre, Clearfield, Westmoreland
			Weighted Average by Transaction Value			**12,747**	

** with flowing $/bbl metric in Marcellus, Utica, Haynesville.

bpx energy

Redacted - Commercially Sensitive Material

2Q20 Trailing 9 Month Cost Structure Details - Permian



** Sum of components equals pre-hedge, oil-equivalent price realization*

	MTDR	PXD	FANG	CXO	PE	CPE	EOG	CDEV	WPX	DVN	XEC	BPX-Permian (incl Midst.)	BPX-Permian	Permian Peer Ave
Hydrocarbon Revenue	$28.4	$29.8	$28.3	$29.1	$26.8	$27.4	$29.0	$26.6	$25.7	$24.2	$17.6	$22.0	$22.0	$26.6
LOE	($4.3)	($4.2)	($4.2)	($5.0)	($3.8)	($5.4)	($4.2)	($4.8)	($5.5)	($3.8)	($3.1)	($10.6)	($10.3)	($4.4)
GP&T	$0.0	($1.7)	($1.3)	($1.5)	($0.9)	($1.4)	($4.3)	($2.7)	($3.4)	($4.1)	($2.3)	($1.6)	($3.5)	($2.1)
Production Taxes	($3.3)	($1.9)	($1.9)	($2.4)	($1.8)	($1.7)	($2.0)	($2.0)	($2.2)	($1.8)	($1.2)	($1.0)	($1.0)	($2.0)
G&A - Total	($2.6)	($1.9)	($0.9)	($2.3)	($2.4)	($1.4)	($1.7)	($2.8)	($2.7)	($3.2)	($1.3)	($2.0)	($2.0)	($2.1)
Other Expense / (Income)	$1.1	($0.8)	($0.9)	$0.2	($0.3)	($0.3)	($0.5)	$0.0	($0.2)	($0.1)	$0.0	($0.4)	($0.4)	($0.2)
Unlevered Cash Margin (pre-hedg	**$19.3**	**$19.2**	**$19.1**	**$18.2**	**$17.6**	**$17.1**	**$16.2**	**$14.3**	**$11.8**	**$11.3**	**$9.8**	**$6.4**	**$4.8**	**$15.8**
Oil Mix	*57%*	*59%*	*62%*	*63%*	*62%*	*66%*	*54%*	*56%*	*61%*	*47%*	*31%*	*49%*	*49%*	*56%*
Margin	*68%*	*64%*	*67%*	*62%*	*66%*	*62%*	*56%*	*54%*	*46%*	*47%*	*56%*	*29%*	*22%*	*59%*

Source: Company Reports, HEA

For comparability BPX financials adjusted to (1) remove production taxes from hydrocarbon revenues (2) include 3rd party gathering expenses in GP&T (rather than LOE)