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Sanchez Energy Business Plan

March 2020

SANCHEZ ENERGY CORPORATION

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Appendix

I. Executive Summary

Business Plan Approach and Summary

The Sanchez Energy management team and advisors ("SN," or the "Company") have been working diligently on a revised business plan, with the goal of maximizing value for stakeholders by focusing on (1) disciplined and optimized capital spend, (2) preservation of optionality for longer-term value realization (with key decision points clearly identified), (3) a simplified and reduced overhead cost structure and (4) a comprehensive midstream solution

- **Approach and Objectives:**
  - The Company has put together the principal "building blocks" of a proposed, going concern business plan for the future owners of the Company, with a primary focus on asset development, midstream and corporate overhead expenses
  - The Company has explored three cases that bookend possible scenarios for the development of the asset base
    - The <u>Option Preservation Case</u> assumes drilling at Catarina to hold the lease through June 2021 (but no longer) and full participation/operatorship at Comanche
    - The <u>Accelerated Completions Case</u> assumes completing the drilled but uncompleted wells ("DUCs") at Catarina, full participation/operatorship at Comanche and no further participation in future drilling across the rest of the asset base
    - The <u>PDP Reference Case</u> assumes completing the drilled but uncompleted wells at Catarina, no participation in future drilling across the rest of the asset base and loss of Comanche operatorship
    - The Company and its advisors are exploring any combination or variants of these cases that maximize value and optionality
  - This process has included significant review, diligence and revisions to the Company's previous plan, with work still ongoing to identify additional upside
  - <u>*All forecasts are preliminary, and conclusions are subject to change based on further and ongoing assessments*</u>
  - <u>*Nothing in this presentation is intended to be a valuation or reflect the Company's or any Company advisor's view on valuation*</u>
- **Key Building Blocks:**
  1. <u>Asset Development</u>
     - Catarina:
       - Option Preservation Case: Retain unique, single ~106,000 acre Catarina lease through 2021 by satisfying current leasehold commitments, but no further drilling after June 2020 (all locations are uneconomic at current prices, and continued activity at historical levels would require a substantial commodity recovery)
       - Accelerated Completions Case: Complete remaining 31 DUCs
     - Comanche: Retain operatorship of entire, multi-lease asset and focus development on highest rate of return opportunities (~50-80 wells per year)
     - At the request of the CRO, the Company's reserves, engineering and development plan assumptions were independently reviewed by the Debtor advisors' technical and E&P teams
       - The technical and E&P teams did not find any variances that would materially change assumptions
       - Feedback has also been solicited from creditor groups, with viable suggestions to be further considered and, if appropriate, incorporated
     - The overarching focus is on a near-term path to free cash flow generation while preserving longer term option value/upside where economically justified
       - We believe this can be achieved through disciplined capital spend on high-graded inventory and leasehold retention wells only
     - See asset development section for additional detail on operational strategy

Business Plan Approach and Summary *(continued)*

- **Key Building Blocks *(continued)*:**

  2. Midstream and Marketing

     - A contract-by-contract financial model was created by SN's midstream team, with no involvement from Sanchez Midstream Partners LP ("SNMP") related personnel, to help inform midstream optimization strategy
       - A comprehensive analysis regarding the value of midstream contract optimization is ongoing
     - The SECO pipeline contract with SNMP was terminated on January 13, 2020 (30-day notice provided to SNMP)

  3. Corporate G&A

     - A revised G&A plan has been created and evaluated on a bottom-up basis by the Company and its advisors

Business Plan Approach and Summary *(continued)*

- **Preliminary Conclusions**:
  - Preliminary analysis indicates higher asset value under the Option Preservation and Accelerated Completions Cases when compared to the PDP Reference Case
  - The Company believes a going concern business model that drills only economic or leasehold retention wells (as part of a near-term option preservation strategy) provides the best opportunity to maximize value for stakeholders
  - While the intentions and preferences of creditors are likely to shape the longer-term business plan, the Company believes a focused operating business provides stakeholders with potential upside opportunities for NAV accretion, as opposed to the PDP Reference Case
  - The material building blocks of the preliminary business plans are subject to additional input and consideration from the future owners of SN (whether they be the creditors or a new buyer), and therefore the assumptions used in these plans are subject to change

- **Open Issues, Ongoing Business Initiatives and Next Steps**:
  1. Net asset value figures contained throughout the presentation have been prepared using the Company's corporate model and corresponding ARIES database, both of which are subject to continuous review and revision by the Company
  2. Ryder Scott is reviewing PDP and PUD forecasts for the Company's year end reserve report
  3. Further legal and financial analysis on midstream strategy
  4. Potential negotiation with Catarina landowner
  5. Discussions with creditor groups around optimal development plan assumptions
  6. Potential capital structure at emergence (e.g., DIP refinancing, reinstated debt, etc.), which is not addressed by the current business plan
  7. Address issues of all other key stakeholders and counterparties, such as Sanchez Oil & Gas Corporation ("SOG"), Gavilan Resources LLC ("Gavilan"), SNMP, GSO Capital Partners, etc.
  8. The business plan may be further revised based on ongoing analysis in the context of maximizing value for the estate

II. Business Plan and Financial Projections

Business Plan Assumptions

The Company and its advisors have conducted a thorough review of business plan assumptions

Assumption	Commentary
Commodity Prices	◆ Strip pricing as of 2/11/20 ◆ Realized prices vs. benchmark prices (WTI and Henry Hub): oil (~93%-98%), natural gas (~100%) and NGLs (~15% of WTI oil price)
Midstream/Marketing	◆ Option Preservation, Accelerated Completions and PDP Reference Cases assume current contracts remain in place (i.e., status quo) ◆ SECO contract terminated with 30-day notice to SNMP in January 2020 ◆ Interruptible gathering rates at Eastern Catarina are held flat at current rate of $1.50/Mcf
Corporate G&A	◆ Projected G&A profile is illustrative; assumes streamlined cost structure, renegotiated office lease and elimination of all non-core expenses under private company emergence assumption ◆ Gross G&A projection in the Option Preservation and Accelerated Completions Cases is reduced to approximately $35-$40MM, before adjustment for COPAS recovery ◆ The operator of oil and gas properties is generally entitled to receive COPAS recovery for reimbursement of expenses incurred on behalf of the other working interest owners of those properties; COPAS recovery to SN from operating Comanche is governed by the JOA and assumed at approximately $950 per well; 3% annual escalation of COPAS reimbursement based on 10-year historical average
Other Operating Expenses/Taxes	◆ Based on 12-month historical averages for each asset from the lease operating statements (“LOS”) ◆ Ad valorem and severance tax rates are based on latest county estimates as a percentage of production
Catarina	◆ Option Preservation Case: Meet drilling requirement (24 additional wells) by June 2020; hold Catarina lease through June 2021; complete all drilled but uncompleted wells (“DUCs”) over the next ~18 months ◆ Accelerated Completions Case: complete remaining DUCs by June 2020
Comanche	◆ High-graded and optimized development schedule for Comanche drilling (~50-80 wells per year for next 6-8 years) ◆ Focus on highest IRR wells within each type curve area, while meeting lease obligations; retains all material leases ◆ Ring-fenced, non-debtor subsidiary SN EF UnSub, LP (“UnSub”) continues to self-fund its portion of new Comanche development spend
Other Assets	◆ Maverick – undeveloped wells uneconomic at current commodity prices; plan assumes PDP only resulting in significant lease expirations ◆ Palmetto – non-consent 2020 development capital (10 wells with unproven type curves with net cost to SN of ~$40 million); potential upside from future option to participate in years 2021+ once well economics have been demonstrated. Non-consenting 2020 development program does not forfeit opportunity to participate in 2021+ development wells ◆ Other non-core assets include the Company’s Tuscaloosa Marine Shale (“TMS”) assets and assets operated by others (“OBO”)
Well Economics	◆ Assumes current authorization for expenditure (“AFE”) estimates based on average lateral length ◆ Corporate model calculates the cost of every well with specific adjustments for lateral length ◆ Well costs supported by historical averages

NAV (PV-10) Analysis and Comparison

- **All forecasts are preliminary, and conclusions are subject to change based on further and ongoing assessments**
- **Nothing in this presentation is intended to be a valuation or reflect the Company's or any Company advisor's view on valuation**

$ millions

Summary NAV Analysis[1]	Option Preservation Case				
	$50/$2.50	Strip[2]	$60/$2.50	$70/$2.50	$80/$2.50
Asset Values (PV-10):					
Catarina[3]	$149	$186	$283	$417	$551
Comanche (Restricted Only)[4]	$49	$77	$140	$230	$321
Maverick	$78	$83	$103	$129	$154
Palmetto	$8	$8	$11	$14	$17
OBO / Other	$3	$3	$4	$5	$5
Asset Value (Pre-G&A)	**$288**	**$357**	**$541**	**$795**	**$1,048**
Total G&A[5]	*($95)*	*($95)*	*($95)*	*($95)*	*($95)*
Asset Value (Post-G&A)	**$193**	**$262**	**$446**	**$700**	**$953**
Est. Upside from Palmetto Participation[6]	$5	$7	$17	$28	$40
Optimized/Upside Asset Value	**$198**	**$269**	**$463**	**$728**	**$993**

Summary NAV Analysis[1]	Accelerated Completions Case				
	$50/$2.50	Strip[2]	$60/$2.50	$70/$2.50	$80/$2.50
Asset Values (PV-10):					
Catarina[3]	$197	$225	$313	$429	$544
Comanche (Restricted Only)[4]	$49	$77	$140	$230	$321
Maverick	$78	$83	$103	$129	$154
Palmetto	$8	$8	$11	$14	$17
OBO / Other	$3	$3	$4	$5	$5
Asset Value (Pre-G&A)	**$336**	**$396**	**$571**	**$806**	**$1,042**
Total G&A[5]	*($95)*	*($95)*	*($95)*	*($95)*	*($95)*
Asset Value (Post-G&A)	**$241**	**$301**	**$476**	**$711**	**$947**
Est. Upside from Palmetto Participation[6]	$5	$7	$17	$28	$40
Optimized/Upside Asset Value	**$246**	**$308**	**$493**	**$739**	**$986**

Summary NAV Analysis[1][7]	PDP Reference Case				
	$50/$2.50	Strip[2]	$60/$2.50	$70/$2.50	$80/$2.50
Asset Values (PV-10):					
Catarina[3]	$197	$225	$313	$429	$544
Comanche (Restricted Only)[4][8]	($19)	($12)	$21	$61	$100
Maverick	$78	$83	$103	$129	$154
Palmetto	$8	$8	$11	$14	$17
OBO / Other	$3	$3	$4	$5	$5
Asset Value (Pre-G&A)	**$268**	**$308**	**$452**	**$637**	**$821**
Total G&A[5]	*($223)*	*($223)*	*($223)*	*($223)*	*($223)*
Asset Value (Post-G&A)	**$45**	**$85**	**$230**	**$414**	**$599**

Notes: All values are preliminary and are calculated based on a 5/31/20 effective date. Strip values were run through the Company's ARIES database. The flat price deck sensitivities are for estimation purposes only. These sensitivities were run in the Excel model which ties closely to the ARIES database but lacks the ability to extend the life of individual wells and/or shut-in production based on pricing (referred to as "LOSSNO").

(1) Valuation excludes estimated cash at emergence. Estimated at approximately $27MM for SN Operating and UR Holdings accounts.

(2) Strip pricing as of 2/11/20.

(3) The estimated split of PV-10 at strip between Central/Eastern and Western Catarina in the Option Preservation Case is 52% ($157MM) and 48% ($142MM), respectively. The estimated PV-10 split ignores field level expenses that are allocated to the entire field (PV-10 -$101MM) and non-D&C capital (-$12MM). The estimated total production split between Central/Eastern and Western Catarina is 43% and 57%, respectively. Note that blended marketing and LOE rates are applied to all wells. For the Accelerated Completions and PDP Reference Cases, the PV-10 split is Central/Eastern 47% ($158MM) and Western 53% ($181MM).

(4) Includes Springfield marketing bands.

(5) Represents 30-year PV-10 of corporate G&A. Includes COPAS recovery PV-10 impact of ~$245MM (Option Preservation), ~$245mm (Accelerated Completions) and $6MM (PDP Reference) for each scenario. Of the COPAS recovery PV-10 impact in the Option Preservation and Accelerated Completions cases, ~21% is attributable to UnSub and ~79% to 3rd parties.

(6) Assumes 50% non-operated participation in remaining economic type curve areas (estimated 11 well inventory) if initial 2020 well results are in-line with Marathon expectations; wells are assumed to be drilled and completed during 2021-2023 and are not included in Option Preservation, Accelerated Completions or PDP Blowdown Reference Case.

(7) Excludes any estimated upside from Palmetto participation as the blowdown case assumes no further D&C capital investment. Potential upside if another operator executes SN's current development plan.

(8) Assumes no development activity as another operator's plan/budget cannot be forecasted.

Illustrative and Preliminary NAV (PV-10) Sensitivities

PV-10 for Option Preservation Case, Accelerated Completions Case and PDP Case at Various Price Decks(1) (2)(3)

($ in millions)

Gas Price (HH)	Oil Price (WTI) – Option Preservation				
	$50	Strip(4)	$60	$70	$80
$2.25	$158	$199	$412	$665	$919
Strip(4)	$189	$262	$443	$696	$950
$2.50	$193	$233	$446	$700	$953
$2.75	$227	$268	$481	$734	$988
$3.00	$262	$302	$515	$769	$1,022

Gas Price (HH)	Oil Price (WTI) – Accelerated Completions				
	$50	Strip(4)	$60	$70	$80
$2.25	$209	$247	$444	$679	$914
Strip(4)	$237	$301	$472	$708	$943
$2.50	$241	$279	$476	$711	$947
$2.75	$273	$311	$508	$744	$979
$3.00	$305	$343	$541	$776	$1,011

Gas Price (HH)	Oil Price (WTI) – PDP Reference Case				
	$50	Strip(4)	$60	$70	$80
$2.25	$18	$46	$202	$387	$571
Strip(4)	$40	$85	$225	$409	$594
$2.50	$45	$73	$230	$414	$599
$2.75	$73	$101	$257	$442	$626
$3.00	$100	$128	$285	$469	$654

Notes: All values are preliminary and are calculated based on a 5/31/20 effective date. Strip values were run through the Company's ARIES database. The flat price deck sensitivities are for estimation purposes only. These sensitivities were run in the Excel model which ties closely to the ARIES database but lacks the ability to extend the life of individual wells and/or shut-in production based on pricing (referred to as "LOSSNO").

(1) Mt. Belvieu Propane is assumed to proportionately increase with WTI (32% of WTI); this results in average realized SN NGL basket pricing of approximately 15% of WTI.

(2) Asset values after G&A (excludes Palmetto participation).

(3) Values excludes estimated cash at emergence.

(4) Strip pricing as of 2/11/20.

Option Preservation Case Financial Projections (Accrual)

$ millions	2017A	2018A	2019E[1]	*Pre-Emergence Jan-May* 2020E	*Post-Emergence Jun-Dec* 2020E	*Full Year* 2020E	2021E	2022E	2023E	2024E
Oil (Boe/d)	15,085	18,026	14,949	11,070	11,891	11,520	12,391	9,871	8,959	8,551
Gas (Mcf/d)	104,638	105,400	89,143	70,384	72,356	71,344	76,633	62,844	54,925	51,322
NGL (Boe/d)	15,171	18,762	15,829	13,193	13,553	13,367	14,357	11,847	10,410	9,789
Total Net Daily Production (Boe/d)	**47,695**	**54,355**	**45,635**	**35,993**	**37,503**	**36,778**	**39,520**	**32,193**	**28,523**	**26,893**
Benchmark Commodity Prices:										
WTI ($/Bbl)	$50.97	$64.66	$57.02	$51.65	$51.00	$51.27	$50.89	$50.96	$51.32	$51.69
Henry Hub ($/Mcf)	$3.11	$3.11	$2.60	$1.87	$2.13	$2.02	$2.36	$2.41	$2.45	$2.47
Mt. Belvieu Propane ($/Bbl)	$20.48	$23.45	$22.46	$16.36	$17.86	$17.24	$18.45	$18.93	$19.30	$19.43
Realized Commodity Prices:										
Oil ($/Bbl)	$49.47	$65.73	$56.34	$49.51	$48.66	$49.00	$48.39	$48.70	$49.22	$49.71
Gas ($/Mcf)	$3.17	$3.14	$2.67	$1.85	$2.11	$2.01	$2.33	$2.39	$2.44	$2.45
NGL ($/Bbl)	$21.10	$23.39	$14.09	$8.32	$9.08	$8.79	$9.33	$9.51	$9.61	$9.58
Oil Revenue	$272	$432	$307	$83	$124	$207	$219	$175	$161	$156
Gas Revenue	121	121	87	20	33	52	65	55	49	46
NGL Revenue	117	160	81	17	26	43	49	41	37	34
Other Sales and Marketing Revenue	---	26	18	---	---	---	---	---	---	---
Oil, Gas, & NGL Revenue	**$510**	**$739**	**$494**	**$119**	**$183**	**$302**	**$333**	**$271**	**$246**	**$236**
Hedge Gain / (Loss)	$5	$(86)	$8	$ ---	$ ---	$ ---	$ ---	$ ---	$ ---	$ ---
Other Sales and Marketing Expenses	---	(24)	(17)	---	---	---	---	---	---	---
Lease Operating Expenses	(49)	(64)	(43)	(13)	(19)	(32)	(32)	(30)	(29)	(29)
Marketing	(108)	(131)	(160)	(58)	(86)	(144)	(145)	(122)	(103)	(92)
Production Taxes	(18)	(30)	(18)	(5)	(7)	(12)	(13)	(11)	(10)	(10)
Ad Valorem Taxes	(5)	(10)	(10)	(2)	(4)	(6)	(7)	(6)	(5)	(5)
Corporate G&A	(114)	(87)	(89)	(25)	(13)	(38)	(15)	(15)	(14)	(14)
Restructuring & Chapter 11 Fees	---	---	(83)	(61)	---	(61)	---	---	---	---
Total G&A	(114)	(87)	(173)	(86)	(13)	(99)	(15)	(15)	(14)	(14)
Reconciling Items to EBITDAX [2]	28	(6)	87	61	---	61	---	---	---	---
Adjusted EBITDAX	**$249**	**$302**	**$167**	**$15**	**$54**	**$69**	**$121**	**$88**	**$84**	**$86**
EBITDA Margin (%)	*49%*	*41%*	*34%*	*13%*	*29%*	*23%*	*36%*	*32%*	*34%*	*37%*
Memo: Total Operating Expenses	*$(261)*	*$(437)*	*$(327)*	*$(104)*	*$(129)*	*$(233)*	*$(212)*	*$(183)*	*$(162)*	*$(150)*
Capex	$(485)	$(512)	$(62)	$(70)	$(79)	$(149)	$(113)	$(50)	$(47)	$(47)
Adjusted EBITDAX Less Capex	**$(236)**	**$(210)**	**$105**	**$(55)**	**$(25)**	**$(80)**	**$8**	**$38**	**$37**	**$39**
Restructuring & Chapter 11 Fees	$ ---	$ ---	$(83)	$(61)	$ ---	$(61)	$ ---	$ ---	$ ---	$ ---
Unlevered Cash Flow (after Ch. 11 Fees)	**$(236)**	**$(210)**	**$21**	**$(115)**	**$(25)**	**$(141)**	**$8**	**$38**	**$37**	**$39**
Memo: Catarina Central / East Volumes (Boe/d) [3]						*12,857*	*13,815*	*10,388*	*8,301*	*7,036*
Memo: COPAS Recovery/(Payment) - 3rd Parties	*$11*	*$19*	*$16*	*$6*	*$9*	*$16*	*$16*	*$17*	*$18*	*$19*
Memo: COPAS Recovery/(Payment) - UnSub	*$2*	*$4*	*$4*	*$2*	*$3*	*$5*	*$5*	*$5*	*$5*	*$5*

Notes: Represents consolidated cash flow forecast net to Debtors. Presented on an accrual basis. Strip pricing as of 2/11/20.

(1) Q4 2019 quarter actuals are estimates and subject to change upon finalized earnings.

(2) Represents non-cash, non-recurring and other amounts included in the above line items which are traditionally added back or excluded in the determination of Adjusted EBITDAX. The amount primarily reflects restructuring fees and certain non-cash adjustments.

(3) Production volumes from ARIES database may not tie exactly to the company model.

Option Preservation Case 2020E Financial Projections (Accrual)

$ millions	Jan 2020E	Feb 2020E	Mar 2020E	Apr 2020E	May 2020E	Jun 2020E	Jul 2020E	Aug 2020E	Sep 2020E	Oct 2020E	Nov 2020E	Dec 2020E	FY 2020E
Oil (Boe/d)	11,012	10,767	10,819	11,392	10,993	10,614	10,097	13,294	13,388	12,566	11,896	11,389	11,520
Gas (Mcf/d)	71,001	69,446	67,779	71,511	69,886	68,105	64,354	74,784	79,188	75,921	73,337	70,914	71,344
NGL (Boe/d)	13,294	13,007	12,706	13,412	13,114	12,780	12,080	13,997	14,803	14,207	13,735	13,286	13,367
Total Net Daily Production (Boe/d)	**36,139**	**35,349**	**34,822**	**36,723**	**35,755**	**34,745**	**32,903**	**39,756**	**41,389**	**39,427**	**37,854**	**36,494**	**36,778**
Benchmark Commodity Prices:													
WTI ($/Bbl)	$57.53	$50.18	$49.94	$50.17	$50.45	$50.68	$50.88	$51.01	$51.07	$51.11	$51.14	$51.11	$51.27
Henry Hub ($/Mcf)	$2.02	$1.83	$1.79	$1.82	$1.88	$1.95	$2.03	$2.07	$2.07	$2.11	$2.24	$2.46	$2.02
Mt. Belvieu Propane ($/Bbl)	$18.06	$15.52	$16.01	$16.07	$16.17	$16.01	$17.17	$17.59	$18.01	$18.38	$18.74	$19.11	$17.24
Realized Commodity Prices:													
Oil ($/Bbl)	$55.18	$48.13	$47.88	$48.05	$48.34	$48.57	$48.77	$48.51	$48.53	$48.68	$48.76	$48.77	$49.00
Gas ($/Mcf)	$2.00	$1.82	$1.77	$1.81	$1.87	$1.94	$2.01	$2.05	$2.05	$2.09	$2.22	$2.44	$2.01
NGL ($/Bbl)	$9.20	$7.90	$8.14	$8.16	$8.20	$8.12	$8.71	$8.96	$9.19	$9.36	$9.53	$9.71	$8.79
Oil Revenue	$19	$15	$16	$16	$16	$15	$15	$20	$19	$19	$17	$17	$207
Gas Revenue	4	4	4	4	4	4	4	5	5	5	5	5	52
NGL Revenue	4	3	3	3	3	3	3	4	4	4	4	4	43
Other Sales and Marketing Revenue	---	---	---	---	---	---	---	---	---	---	---	---	---
Oil, Gas, & NGL Revenue	**$27**	**$22**	**$23**	**$24**	**$24**	**$23**	**$23**	**$29**	**$28**	**$28**	**$26**	**$27**	**$302**
Hedge Gain / (Loss)	$ ---	$ ---	$ ---	$ ---	$ ---	$ ---	$ ---	$ ---	$ ---	$ ---	$ ---	$ ---	$ ---
Other Sales and Marketing Expenses	---	---	---	---	---	---	---	---	---	---	---	---	---
Lease Operating Expenses	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(32)
Marketing	(12)	(11)	(12)	(12)	(12)	(11)	(11)	(13)	(13)	(13)	(12)	(12)	(144)
Production Taxes	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(12)
Ad Valorem Taxes	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(6)
Corporate G&A	(5)	(5)	(5)	(5)	(5)	(5)	(1)	(1)	(1)	(1)	(1)	(1)	(38)
Restructuring & Chapter 11 Fees	(9)	(8)	(9)	(9)	(26)	---	---	---	---	---	---	---	(61)
Total G&A	(13)	(13)	(14)	(14)	(32)	(5)	(1)	(1)	(1)	(1)	(1)	(1)	(99)
Reconciling Items to EBITDAX (1)	9	8	9	9	26	---	---	---	---	---	---	---	61
Adjusted EBITDAX	**$6**	**$2**	**$3**	**$2**	**$2**	**$2**	**$6**	**$10**	**$9**	**$9**	**$8**	**$9**	**$69**
EBITDA Margin (%)	*22%*	*9%*	*11%*	*10%*	*10%*	*8%*	*27%*	*34%*	*33%*	*33%*	*32%*	*33%*	*23%*
Memo: Total Operating Expenses	*$(21)*	*$(20)*	*$(20)*	*$(21)*	*$(21)*	*$(21)*	*$(17)*	*$(19)*	*$(19)*	*$(19)*	*$(18)*	*$(18)*	*$(233)*
Capex	$(8)	$(22)	$(16)	$(14)	$(10)	$(36)	$(20)	$(7)	$(3)	$(3)	$(5)	$(4)	$(149)
Adjusted EBITDAX Less Capex	**$(2)**	**$(20)**	**$(14)**	**$(12)**	**$(7)**	**$(34)**	**$(14)**	**$3**	**$6**	**$6**	**$3**	**$4**	**$(80)**
Restructuring & Chapter 11 Fees	$(9)	$(8)	$(9)	$(9)	$(26)	$ ---	$ ---	$ ---	$ ---	$ ---	$ ---	$ ---	$(61)
Unlevered Cash Flow (after Ch. 11 Fees)	**$(10)**	**$(28)**	**$(22)**	**$(21)**	**$(33)**	**$(34)**	**$(14)**	**$3**	**$6**	**$6**	**$3**	**$4**	**$(141)**
Memo: Catarina Central / East Volumes (Boe/d) (2)	*13,137*	*13,587*	*12,317*	*12,350*	*13,694*	*13,478*	*12,522*	*12,078*	*13,931*	*12,793*	*12,664*	*11,808*	*12,857*
Memo: COPAS Recovery/(Payment) - 3rd Parties	*$1.3*	*$1.3*	*$1.3*	*$1.3*	*$1.3*	*$1.3*	*$1.3*	*$1.3*	*$1.3*	*$1.4*	*$1.4*	*$1.4*	*$15.7*
Memo: COPAS Recovery/(Payment) - UnSub	*$0.4*	*$0.4*	*$0.4*	*$0.4*	*$0.4*	*$0.4*	*$0.4*	*$0.4*	*$0.4*	*$0.4*	*$0.4*	*$0.4*	*$4.5*

Notes: Represents consolidated cash flow forecast net to Debtors. Presented on an accrual basis. Strip pricing as of 2/11/20.

(1) Represents non-cash, non-recurring and other amounts included in the above line items which are traditionally added back or excluded in the determination of Adjusted EBITDAX. The amount primarily reflects restructuring fees and certain non-cash adjustments.

(2) Production volumes from ARIES database may not tie exactly to the company model.

Accelerated Completions Case Financial Projections (Accrual)

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				Pre-Emergence Jan-May	*Post-Emergence Jun-Dec*	*Full Year*				
$ millions	**2017A**	**2018A**	**2019E[1]**	**2020E**	**2020E**	**2020E**	**2021E**	**2022E**	**2023E**	**2024E**
Oil (Boe/d)	15,085	18,026	14,949	11,374	12,941	12,259	9,949	8,658	8,212	8,001
Gas (Mcf/d)	104,638	105,400	89,143	72,128	79,765	76,396	64,498	55,569	50,308	47,897
NGL (Boe/d)	15,171	18,762	15,829	13,515	14,919	14,299	12,118	10,505	9,558	9,157
Total Net Daily Production (Boe/d)	**47,695**	**54,355**	**45,635**	**36,910**	**41,155**	**39,291**	**32,817**	**28,425**	**26,154**	**25,140**
Benchmark Commodity Prices:										
WTI ($/Bbl)	$50.97	$64.66	$57.02	$51.65	$51.00	$51.27	$50.89	$50.96	$51.32	$51.69
Henry Hub ($/Mcf)	$3.11	$3.11	$2.60	$1.87	$2.13	$2.02	$2.36	$2.41	$2.45	$2.47
Mt. Belvieu Propane ($/Bbl)	$20.48	$23.45	$22.46	$16.36	$17.86	$17.24	$18.45	$18.93	$19.30	$19.43
Realized Commodity Prices:										
Oil ($/Bbl)	$49.47	$65.73	$56.34	$49.48	$48.55	$48.90	$48.66	$48.89	$49.36	$49.82
Gas ($/Mcf)	$3.17	$3.14	$2.67	$1.85	$2.11	$2.01	$2.34	$2.39	$2.44	$2.45
NGL ($/Bbl)	$21.10	$23.39	$14.09	$8.33	$9.10	$8.80	$9.33	$9.47	$9.57	$9.54
Oil Revenue	$272	$432	$307	$85	$134	$219	$177	$154	$148	$146
Gas Revenue	121	121	87	20	36	56	55	49	45	43
NGL Revenue	117	160	81	17	29	46	41	36	33	32
Other Sales and Marketing Revenue	---	26	18	---	---	---	---	---	---	---
Oil, Gas, & NGL Revenue	**$510**	**$739**	**$494**	**$122**	**$199**	**$322**	**$273**	**$239**	**$226**	**$221**
Hedge Gain / (Loss)	$5	$(86)	$8	$ ---	$ ---	$ ---	$ ---	$ ---	$ ---	$ ---
Other Sales and Marketing Expenses	---	(24)	(17)	---	---	---	---	---	---	---
Lease Operating Expenses	(49)	(64)	(43)	(13)	(19)	(32)	(30)	(29)	(29)	(29)
Marketing	(108)	(131)	(160)	(58)	(92)	(149)	(131)	(112)	(96)	(87)
Production Taxes	(18)	(30)	(18)	(5)	(8)	(13)	(11)	(10)	(9)	(9)
Ad Valorem Taxes	(5)	(10)	(10)	(3)	(4)	(7)	(6)	(5)	(5)	(5)
Corporate G&A	(114)	(87)	(89)	(25)	(13)	(38)	(15)	(15)	(14)	(14)
Restructuring & Chapter 11 Fees	---	---	(83)	(61)	---	(61)	---	---	---	---
Total G&A	(114)	(87)	(173)	(86)	(13)	(99)	(15)	(15)	(14)	(14)
Reconciling Items to EBITDAX [2]	28	(6)	87	61	---	61	---	---	---	---
Adjusted EBITDAX	**$249**	**$302**	**$167**	**$18**	**$63**	**$82**	**$79**	**$68**	**$73**	**$78**
EBITDA Margin (%)	*49%*	*41%*	*34%*	*15%*	*32%*	*25%*	*29%*	*29%*	*32%*	*35%*
Memo: Total Operating Expenses	*$(261)*	*$(437)*	*$(327)*	*$(104)*	*$(136)*	*$(240)*	*$(194)*	*$(171)*	*$(153)*	*$(143)*
Capex	$(485)	$(512)	$(62)	$(97)	$(28)	$(125)	$(38)	$(50)	$(47)	$(47)
Adjusted EBITDAX Less Capex	**$(236)**	**$(210)**	**$105**	**$(78)**	**$35**	**$(43)**	**$41**	**$18**	**$26**	**$31**
Restructuring & Chapter 11 Fees	$ ---	$ ---	$(83)	$(61)	$ ---	$(61)	$ ---	$ ---	$ ---	$ ---
Unlevered Cash Flow (after Ch. 11 Fees)	**$(236)**	**$(210)**	**$21**	**$(139)**	**$35**	**$(104)**	**$41**	**$18**	**$26**	**$31**
Memo: Catarina Central / East Volumes (Boe/d) [3]						*13,779*	*10,754*	*8,431*	*7,073*	*6,127*
Memo: COPAS Recovery/(Payment) - 3rd Parties	*$11*	*$19*	*$16*	*$6*	*$9*	*$16*	*$16*	*$17*	*$18*	*$19*
Memo: COPAS Recovery/(Payment) - UnSub	*$2*	*$4*	*$4*	*$2*	*$3*	*$5*	*$5*	*$5*	*$5*	*$5*

Notes: Represents consolidated cash flow forecast net to Debtors. Presented on an accrual basis. Strip pricing as of 2/11/20.

(1) Q4 2019 quarter actuals are estimates and subject to change upon finalized earnings.

(2) Represents non-cash, non-recurring and other amounts included in the above line items which are traditionally added back or excluded in the determination of Adjusted EBITDAX. The amount primarily reflects restructuring fees and certain non-cash adjustments.

(3) Production volumes from ARIES database may not tie exactly to the company model.

Accelerated Completions Case 2020E Financial Projections (Accrual)

$ millions	Jan 2020E	Feb 2020E	Mar 2020E	Apr 2020E	May 2020E	Jun 2020E	Jul 2020E	Aug 2020E	Sep 2020E	Oct 2020E	Nov 2020E	Dec 2020E	FY 2020E
Oil (Boe/d)	11,012	10,767	10,644	11,623	12,428	12,009	15,829	13,954	12,858	12,432	11,933	11,509	12,259
Gas (Mcf/d)	71,001	69,446	67,040	71,719	78,922	74,899	90,310	85,047	80,876	78,045	75,643	73,279	76,396
NGL (Boe/d)	13,294	13,007	12,570	13,451	14,781	14,033	16,869	15,890	15,115	14,599	14,161	13,722	14,299
Total Net Daily Production (Boe/d)	**36,139**	**35,349**	**34,387**	**37,027**	**40,363**	**38,525**	**47,749**	**44,019**	**41,452**	**40,039**	**38,701**	**37,444**	**39,291**
Benchmark Commodity Prices:													
WTI ($/Bbl)	$57.53	$50.18	$49.94	$50.17	$50.45	$50.68	$50.88	$51.01	$51.07	$51.11	$51.14	$51.11	$51.27
Henry Hub ($/Mcf)	$2.02	$1.83	$1.79	$1.82	$1.88	$1.95	$2.03	$2.07	$2.07	$2.11	$2.24	$2.46	$2.02
Mt. Belvieu Propane ($/Bbl)	$18.06	$15.52	$16.01	$16.07	$16.17	$16.01	$17.17	$17.59	$18.01	$18.38	$18.74	$19.11	$17.24
Realized Commodity Prices:													
Oil ($/Bbl)	$55.18	$48.13	$47.90	$48.02	$48.18	$48.40	$48.25	$48.45	$48.57	$48.69	$48.76	$48.76	$48.90
Gas ($/Mcf)	$2.00	$1.82	$1.77	$1.81	$1.87	$1.93	$2.01	$2.05	$2.05	$2.09	$2.22	$2.44	$2.01
NGL ($/Bbl)	$9.20	$7.90	$8.14	$8.16	$8.23	$8.14	$8.77	$8.98	$9.19	$9.36	$9.54	$9.72	$8.80
Oil Revenue	$19	$15	$16	$17	$19	$17	$24	$21	$19	$19	$17	$17	$219
Gas Revenue	4	4	4	4	5	4	6	5	5	5	5	6	56
NGL Revenue	4	3	3	3	4	3	5	4	4	4	4	4	46
Other Sales and Marketing Revenue	—	—	—	—	—	—	—	—	—	—	—	—	—
Oil, Gas, & NGL Revenue	**$27**	**$22**	**$23**	**$24**	**$27**	**$25**	**$34**	**$31**	**$28**	**$28**	**$27**	**$27**	**$322**
Hedge Gain / (Loss)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Other Sales and Marketing Expenses	—	—	—	—	—	—	—	—	—	—	—	—	—
Lease Operating Expenses	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(32)
Marketing	(12)	(11)	(11)	(11)	(13)	(12)	(15)	(14)	(13)	(13)	(12)	(12)	(149)
Production Taxes	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(13)
Ad Valorem Taxes	(1)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(7)
Corporate G&A	(5)	(5)	(5)	(5)	(5)	(5)	(1)	(1)	(1)	(1)	(1)	(1)	(38)
Restructuring & Chapter 11 Fees	(9)	(8)	(9)	(9)	(26)	—	—	—	—	—	—	—	(61)
Total G&A	(13)	(13)	(14)	(14)	(32)	(5)	(1)	(1)	(1)	(1)	(1)	(1)	(99)
Reconciling Items to EBITDAX [(1)]	9	8	9	9	26	—	—	—	—	—	—	—	61
Adjusted EBITDAX	**$6**	**$2**	**$3**	**$3**	**$4**	**$4**	**$13**	**$11**	**$9**	**$9**	**$9**	**$9**	**$82**
EBITDA Margin (%)	*23%*	*10%*	*12%*	*12%*	*15%*	*14%*	*37%*	*35%*	*33%*	*33%*	*33%*	*34%*	*25%*
Memo: Total Operating Expenses	*$(21)*	*$(19)*	*$(20)*	*$(21)*	*$(23)*	*$(22)*	*$(21)*	*$(20)*	*$(19)*	*$(19)*	*$(18)*	*$(18)*	*$(240)*
Capex	$(8)	$(16)	$(21)	$(5)	$(46)	$(6)	$(1)	$(5)	$(3)	$(3)	$(5)	$(4)	$(125)
Adjusted EBITDAX Less Capex	**$(1)**	**$(14)**	**$(19)**	**$(2)**	**$(42)**	**$(3)**	**$12**	**$6**	**$6**	**$6**	**$3**	**$5**	**$(43)**
Restructuring & Chapter 11 Fees	$(9)	$(8)	$(9)	$(9)	$(26)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$(61)
Unlevered Cash Flow (after Ch. 11 Fees)	**$(10)**	**$(22)**	**$(28)**	**$(11)**	**$(68)**	**$(3)**	**$12**	**$6**	**$6**	**$6**	**$3**	**$5**	**$(104)**
Memo: Catarina Central / East Volumes (Boe/d) [(2)]	*13,137*	*13,587*	*12,317*	*12,350*	*13,694*	*15,761*	*14,295*	*15,367*	*14,924*	*13,728*	*13,579*	*12,640*	*13,779*
Memo: COPAS Recovery/(Payment) - 3rd Parties	*$1.3*	*$1.3*	*$1.3*	*$1.3*	*$1.3*	*$1.3*	*$1.3*	*$1.3*	*$1.3*	*$1.4*	*$1.4*	*$1.4*	*$15.7*
Memo: COPAS Recovery/(Payment) - UnSub	*$0.4*	*$0.4*	*$0.4*	*$0.4*	*$0.4*	*$0.4*	*$0.4*	*$0.4*	*$0.4*	*$0.4*	*$0.4*	*$0.4*	*$4.5*

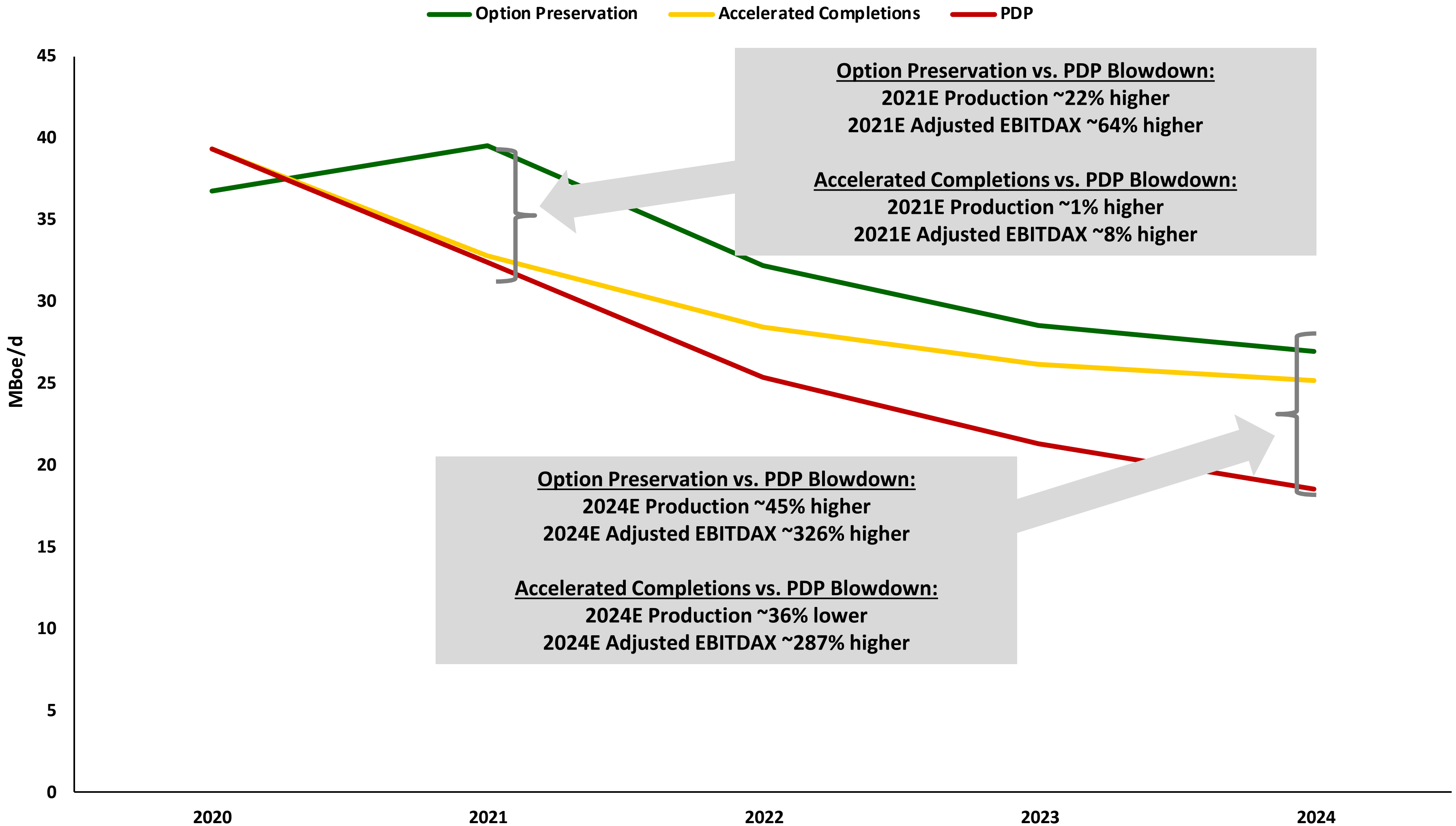
Notes: Represents consolidated cash flow forecast net to Debtors. Presented on an accrual basis. Strip pricing as of 2/11/20.

(1) Represents non-cash, non-recurring and other amounts included in the above line items which are traditionally added back or excluded in the determination of Adjusted EBITDAX. The amount primarily reflects restructuring fees and certain non-cash adjustments.

(2) Production volumes from ARIES database may not tie exactly to the company model.

Option Preservation Case Provides Commodity Price Upside

A going concern company best positions the assets for future rebound in commodity prices or monetization



Note: Assumes strip pricing as of 2/11/20.

Key Ongoing Business Initiatives

Immediate steps have been taken to delay capital spend, optimize operations and reduce costs; the Company is focused on key ongoing business initiatives to maximize asset value

Asset Development	◆ **The drilling program at Catarina was thoroughly reviewed, with timing for continued activity pushed approximately one month, from early January to early February 2020; the existing rig was moved from Catarina to Comanche during the first week of January; as part of this review, the Company's drilling schedule was optimized, resulting in an overall lower rig count** ◆ The revised development plan has been designed to preserve the asset base and maintain optionality while minimizing near-term capital outlay ◆ The business plan assumes drilling only economic wells (minimum threshold of 20% IRR[(1)]), unless certain wells are required to be drilled to retain a major lease under CDC obligations – if the Accelerated Completions Case were to be adopted, the remaining DUC inventory would be completed with no further development activity in Catarina after June 2020 ◆ The Company currently has 3 rigs across the entire asset base (1 at Catarina and 2 at Comanche); however, not all are active ◆ In the event that the Company pursues a plan that involves the drilling of additional wells in Catarina, that plan would result in 2 active rigs at Catarina and 1 at Comanche
Midstream	◆ **The SECO midstream contract was terminated on January 13, 2020, with 30-day notice provided to SNMP** ◆ Midstream contract optimization opportunities are being evaluated, with consideration of commercial, economic and legal implications ◆ Value accretion to both SN and SNMP may be available through the Debtors' midstream optimization strategy; any value that may be captured by SNMP will be addressed through a comprehensive renegotiation (with the goal of capturing maximum value for SN and providing infill gathering rate certainty in Eastern Catarina)
Corporate G&A	◆ **Non-essential overhead expenses, such as the company ranch participation, have been rejected or eliminated, saving approximately $2MM per annum on a run-rate basis; additional cost savings may be realized in the near-term through ongoing G&A review and contract renegotiation and/or rejection** ◆ Corporate G&A has been thoroughly reviewed by management, with a proposed plan to reduce overhead expenses from approximately $75MM (~$3.00/Boe) in 2019 to an average of approximately $19MM consolidated G&A after COPAS reimbursement (~$1.50/Boe) from 2021 through 2025
Asset Lease Preservation	◆ Catarina: TBD ◆ All major leases at Comanche are being reviewed on a case-by-case basis

Note:
(1) IRR calculated at $50 oil/$2.50 gas/$14 NGL price deck.

Key Near Term Operational Decisions (2020)

Outlined below are key operational decisions over the next 12 months

Category	Decision
Catarina	<u>**Option Preservation**</u> ◆ Drill remaining 24 wells required in the 2019-2020 lease period – *Project Capital: $45.0MM* ◆ Complete 5 DUCs scheduled in February – *Project Capital: $11.8MM completions + $1.3MM infrastructure and non-D&C* ◆ Complete 18 DUCs scheduled in June – *Project Capital: $45.6MM completions + $4.7MM infrastructure and non-D&C* ◆ Drill required wells for 2020-2021 lease term – *Source rigs for contract, September 2020 spud for 2-rig program* ◆ Leaves 31 DUCs to be completed in 2021 – *Project Capital: $66.2MM completions + $8.0MM infrastructure and non-D&C* <u>**Accelerated Completions**</u> ◆ Complete 31 DUCs scheduled through June ◆ *Project Capital: $1.9MM drilling (Feb/Mar 2020 only) + $73.9MM completions + $8.0MM infrastructure and non-D&C*
Comanche	◆ Renegotiate lease in La Bandera/FOGMT – *Current lease terms expire in April 2020* ◆ Drill required wells for 2020-2021 lease terms – *Source rigs for contract* ◆ Renegotiate lease in Maund – *Current lease terms expire in March 2021*
Midstream/ Marketing	◆ TBD

Potential Risks and Upsides to the Proposed Business Plan

Risk/Considerations	
Commodity Prices	◆ Further degradation in commodity prices, realizations or differentials
Loss of Comanche Operatorship	◆ No longer in control of development plan and capital spend ◆ Lose ability to collect COPAS from working interest partners and would have to reimburse new operator ◆ Likely lower value in a monetization given lack of control
Midstream Rates	◆ Interruptible gathering rate on Eastern Catarina could be increased by SNMP ◆ Comanche infield gathering rates could increase with cost of service model if volumes significantly decline
G&A Plan	◆ The proposed reduction in G&A corresponds to a reduction in required drilling operations per the business plan ◆ Talent retention may be difficult

Potential Upside to Business Plan Forecast	
Commodity Prices	◆ Improvement in commodity prices, realizations or differentials ◆ Improved commodity prices would also unlock additional inventory that can be drilled at economic returns
Contract Optimization	◆ TBD
Type Curve Outperformance	◆ The Company has outperformed production by ~5% compared to its original 2019 budget ◆ Many of the Company's type curves have been recently refreshed at year-end based on new well data
Palmetto	◆ If Marathon's 2020 development test is successful, the Company could participate in future development ◆ If Marathon's tests are not successful, the Company would still participate in cash flow sharing through an Overriding Royalty Interest ("ORRI") election that requires no capital spend on projects proposed in the first 8 months of a given lease year (1% override that converts to a 17.5% working interest after 1.0x payout)
Catarina Lease CDC Relief	◆ While unlikely, if landowners are willing to provide near-term relief on drilling requirements, the Company could realize significant value from avoiding uneconomic wells and redirecting budgeted capex dollars towards completion activity

III. Asset Development Plan

Asset Development Approach and Overview

A comprehensive asset development assessment was completed since the last business plan presentation

Strategy	◆ Previous mandate focused on holding assets together and preventing lease expiration as the primary driving objective ◆ Current strategy focuses on economic drilling and preserving optionality in the most cost-effective manner
Asset Summary	◆ ~435,000 gross (~233,000 net) acres in the Eagle Ford ◆ More than half of net acreage is held by production and annual/continuous drilling obligations ◆ Diversified, lower decline production from significant PDP base with over 2,200 wells (on a gross basis)
Catarina Type Curves	◆ Catarina type curves were reviewed and refreshed in Q4 2019 with the benefit of an additional 12 months of production history ◆ Type curve boundaries adjusted to incorporate similar well performance, rock properties, fluid properties and seismic characteristics ◆ As a result, significant inventory was lost and others shifted from South Central Catarina to Central Catarina, with no remaining "legacy" South Central locations
Comanche Type Curves	◆ Utilized recent well performance results with wider well spacing and larger completion designs to refine type curves ◆ Identified and incorporated into forecast material changes to some type curves from development plan changes ◆ Inventory was reduced as a result of increased well spacing and removal of uneconomic targets/infill locations
Inventory	◆ Complete refresh of inventory based on current development planning and spacing assumptions ◆ Created map layers that tie individual sticks on a map to model and ARIES
Drilling and Completion Costs	◆ Updated to incorporate lower unit costs (sand and horsepower) and drilling and completion efficiencies (7.5 stages/day) ◆ Approximately ~12%-15% per well savings incorporated into business plan vs. 2019 budgeted costs
Engineering and Financial Diligence	◆ The Debtor advisors' engineering team evaluated and performed diligence on the geological and technical aspects of the business plan ◆ The Debtor advisors reviewed the cost and expense assumptions for each asset ◆ Creditor feedback on development plan is being considered and may be incorporated where appropriate and value maximizing

Catarina Asset Overview

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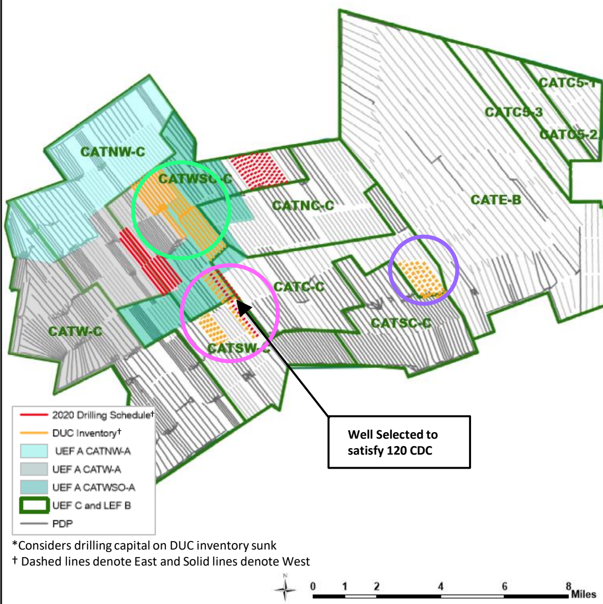
Asset Map



*Considers drilling capital on DUC inventory sunk
† Dashed lines denote East and Solid lines denote West

E35-E36 (East)
- 5 DUCs Drilled Q418
- $10.8MM required to frac
- AVG 26% IRR* at $50 WTI

A44-A45 (West)
- 18 DUCs Drilled Q418 - Q319
- $47.2 MM required to frac
- AVG 35% IRR* at $50 WTI

E37-E39 (East)
- 7 DUCs Drilled Q419
- 4 Remain to be drilled
- $32.8 MM required to Finish drilling and Frac
- AVG 26% IRR* at $50 WTI

Lease Summary

- ~106,000 gross / net acres
- EF wet gas / condensate window
- Annual lease term July 1-June 30
- 50-well annual drilling commitment
- 100% WI and 75% NRI
- Oil/Gas/NGL: 24%/37%/40%
- **2019 Production:** ~35,000 Boe/d
- **PDP Count:** 457 wells
- **Current DUC Inventory:** 30 wells
- **Total Planned 2020 Spuds / TTP:**
  - **Option Preservation**: 24 wells / 23 wells
  - **Accelerated Completions**: 1 well / 31 wells

Rig – Completion Schedule

Option Preservation

Activity	JAN 2020	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN 2021	FEB	MAR
Drilling *Well Count*		4	6	6	5	3									
Online *Well Count*			5				10	8						17	14

Accelerated Completions

Activity	JAN 2020	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN 2021	FEB	MAR
Drilling *Well Count*		1													
Online *Well Count*			5	8		18									

*Gross

Inventory Analysis

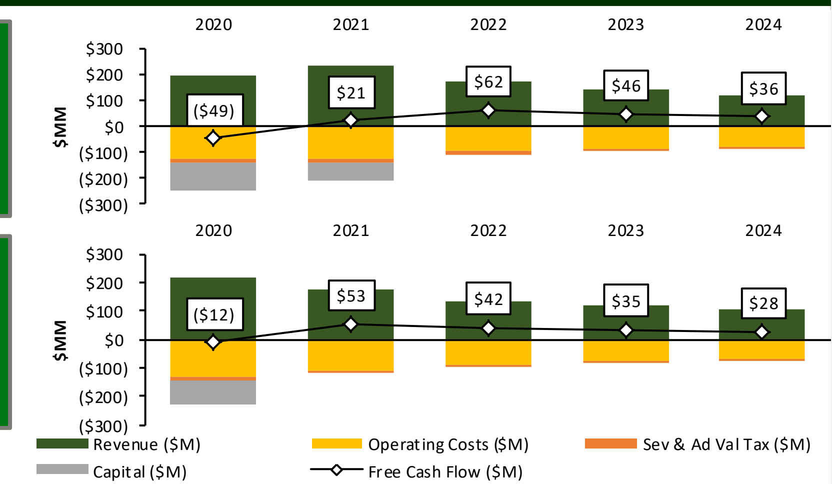
TC Area	Development Plan: Drilled	AVG IRR @ $50	Wells
CATWSO-A	6	45%	6
CATC-C	5	26%	11
CATW-A	18	20%	29
CATWSO-C	16	12%	45
CATSW-C	6	13%	51
CATNW-C	3	0%	54
CATSC-C	-	-	-
CATW-C	-	-	-
CATNC-C	-	-	-
CATNW-A	-	-	-
CATC5 - TIER1	-	-	-
CATC5 - TIER2	-	-	-
CATC5 - TIER3	-	-	-
CATE-B	-	-	-
Total	54		

TC Area	Undeveloped Inventory: Count	WTI for 20% IRR	Cumulative Wells
CATC5 - TIER1	12	$65	12
CATNW-A	16	68	28
CATWSO-C	12	71	40
CATWSO-A	9	74	49
CATNC-C	44	76	93
CATC5 - TIER2	12	76	105
CATNW-C	17	77	122
CATSW-C	35	82	157
CATC-C	28	84	185
CATC5 - TIER3	16	84	201
CATW-A	1	89	202
CATE-B	152	107	354
Total	354		

Asset Level Cash Flow

Option Preservation

Accelerated Completions



Comanche Asset Overview

Asset Map

Lease Summary

- ~250,000 gross / ~61,000 net acres
- EF volatile oil / condensate gas window
- 23 separate lease commitments
- ~40-60 well per year drilling commitment
- **2019 Production:** ~28,000 Boe/d
- **Gross PDP Count:** 1,738 wells
- **Total Planned 2020 Spuds:** 55 wells
- **Total Planned 2020 TTP**: 57 wells
- Average ~24% WI and ~18% NRI; Restricted average ~6% WI and ~4% NRI
- Oil/Gas/NGL: 37%/30%/33%; Restricted Oil/Gas/NGL: 45%/26%/29%

Rig – Completion Schedule

	2020											2021		
Activity	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR
Drilling															
Well Count	11	3	2	5		5	3	4	3	6	9	4	7	4	
Online															
Well Count	3	13	3	6	3		1		11	7	3	7	8	18	3

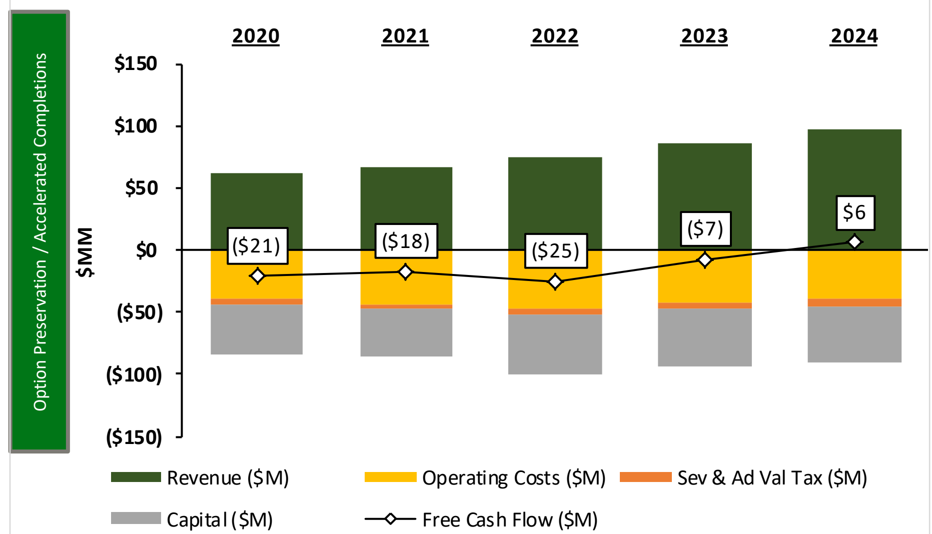
*Gross

Inventory Analysis

TC Area	Developed Inventory Count	AVG IRR @ $50	Cumulative Wells
AREA-3-2	20	52%	20
AREA-5-7	28	52%	48
AREA-3-1B	34	50%	82
AREA-3-1A	41	47%	123
AREA-7-1	40	47%	163
AREA-7-2	33	41%	196
AREA-3-3S	23	40%	219
AREA-3-3	75	37%	294
AREA-4-1	46	33%	340
AREA-5-1	11	27%	351
AREA-3-3_UEFAC_Gen10	21	22%	372
AREA-3-4	41	21%	413
AREA-5-3	9	17%	422
CATNW	5	16%	427
AREA-2-1	7	6%	434
AREA-3-4_UEFAC	4	3%	438
AREA-3-1C	6	2%	444
AREA 1	-	-	-
AREA 2-2	-	-	-
AREA 2-3	-	-	-
AREA-3-1B_UEFAC	-	-	-
AREA-3-2_UEFB	-	-	-
AREA-3-3_UEFAC_Gen2	-	-	-
AREA 4-2	-	-	-
AREA 5-2	-	-	-
AREA 5-4	-	-	-
AREA 6-1	-	-	-
MAVERICK	-	-	-
Total	444		

TC Area	Undeveloped Inventory Count	WTI for 20% IRR	Cumulative Wells
AREA 7-1	4	$32	4
AREA-7-2	1	35	5
AREA-3-2	1	45	6
AREA 3-1B	12	51	18
MAVERICK	46	52	64
AREA-3-3S	1	52	65
AREA 3-3	11	56	76
AREA-5-1	11	61	87
CATNW	12	61	99
AREA-5-3	31	62	130
AREA-5-7	6	63	136
AREA-3-3_UEFAC_Gen10	108	67	244
AREA-5-2	37	68	281
AREA-3-1A	5	75	286
AREA-6-1	12	79	298
AREA-2-3	94	82	392
AREA-3-3	14	82	406
AREA-3-1C	22	83	428
AREA-4-2	81	83	509
AREA-4-1	194	86	703
AREA-3-4	38	90	741
AREA-2-1	100	91	841
AREA-2-2	118	93	959
AREA-3-2_UEFB	93	97	1,052
AREA-1	67	99	1,119
AREA-5-4	63	100	1,182
AREA-3-2_UEFB	1	119	1,183
AREA-3-4_UEFAC	282	130	1,465
AREA-3-3_UEFAC_Gen2	217	311	1,682
AREA-3-1B_UEFAC	26	312	1,708
Total	1,708		

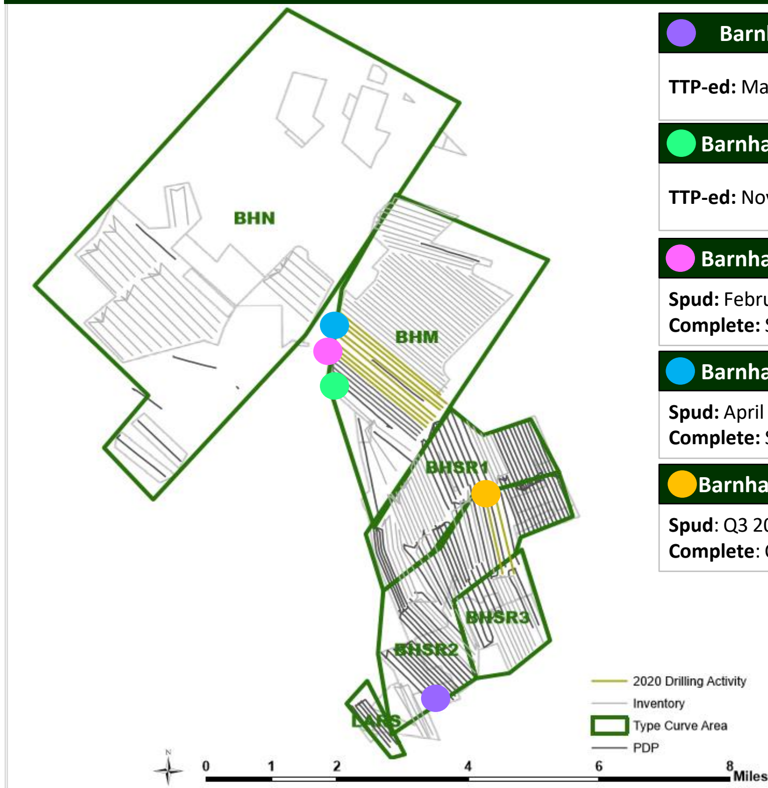
Asset Level Cash Flow (Restricted)



Note: Development plan counts are as of 1/1/20 and Comanche's maverick type curve area is largely exploratory with no wells on lease. Individual wells that appear economic at lower prices are isolated and have certain physical operational hinderances to drilling.

Palmetto Asset Overview

Asset Map



Barnhart G Pad

TTP-ed: May 2019

Barnhart 100-103H

TTP-ed: November 2019

Barnhart 104-107H

Spud: February 2020
Complete: Summer 2020

Barnhart 108-111H

Spud: April 2020
Complete: Summer 2020

Barnhart 48H – 49H

Spud: Q3 2020
Complete: Q4 2020

Lease Summary

- ~15,500 gross / ~7,500 net acres
- EF black oil window
- Annual drilling commitment based on WTI
- Average 50% WI and 36.35% NRI
- Oil/Gas/NGL: 69%/15%/16%
- **2019 Production:** ~1,000 Boe/d
- **Gross PDP Count:** 83 wells
- **Total Planned 2020 Spuds[(1)]:** 10 wells
- **Total Planned 2020 TTP[(1)]:** 10 wells

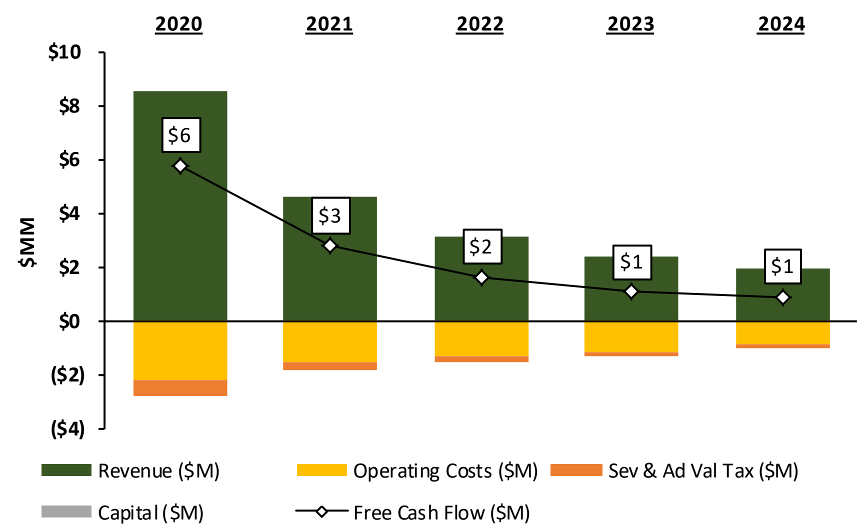
Rig – Completion Schedule[(1)]

	2020											2021		
Activity	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR
Drilling *Well Count*															
Online *Well Count*															

Inventory Analysis

		Development Plan		Undeveloped Inventory	
TC Area	**Target**	**Drilled**	**Avg. IRR @ $50**	**Count**	**Avg. IRR @ $55**
BHM	LEF B	-	-	17	10%
BHM – 10,000'	LEF B	8	18%	23	18%
BHN	LEF B	-	-	27	2%
BHS R1	LEF B	-	-	21	9%
BHS R2	LEF B	2	6%	13	6%
BHS R3	LEF B	-	-	11	0%
	Total	10		112	

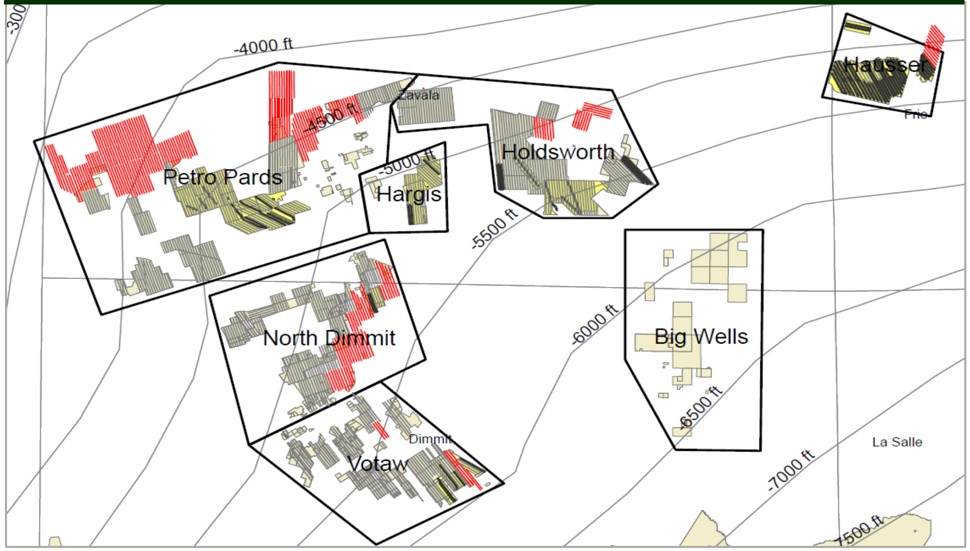
Asset Level Cash Flow



(1) *Marathon (operator) intends to drill and complete 10 wells in 2020. Due to near term considerations, SN has elected not to participate in 8 of 10, without leasehold risk. Remaining elections pending.*
(2) *Represents gross well economics; new money returns on these 8 wells, net of SN's ORRI, is approximately 25%.*

Maverick Asset Overview

Asset Map



Lease Summary

- ~62,000 gross / ~40,000 net acres
- ~24,316 net acres held by production
- EF volatile oil / black oil
- 100% WI and 75% NRI
- Oil/Gas/NGL: 97%/2%/2%
- **2019 Production:** ~2,600 Boe/d
- **Gross PDP Count:** 79 wells
- **Total Planned 2020 Spuds:** 0 wells
- **Total Planned 2020 TTP**: 0 wells

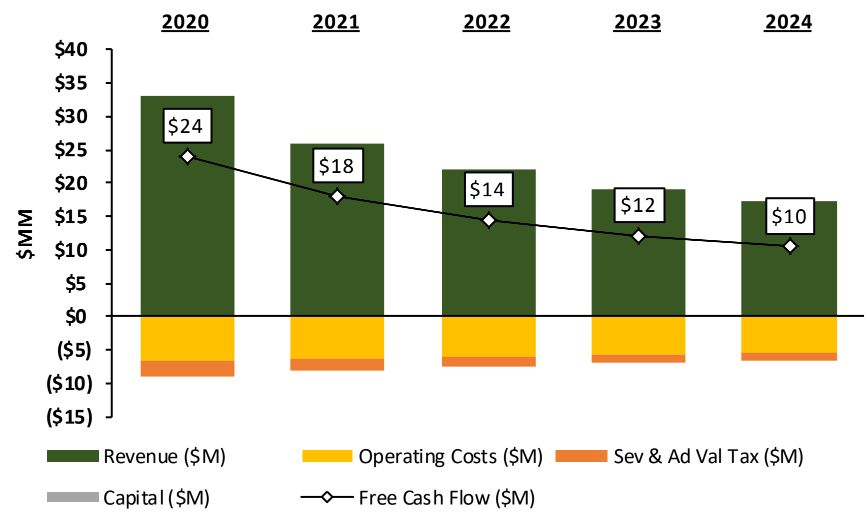
Rig – Completion Schedule

	2020												2021		
Activity	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR
Drilling *Well Count*															
Online *Well Count*															

Inventory Analysis

TC Area	Target	Inventory Summary: Development	Count	HBP	WTI for 20% IRR
HAUSSER	LEF B	0	5	5	$62
NORTH DIMMIT	LEF B	0	55	4	$64
VOTAW	LEF B	0	42	29	$66
HOLDSWORTH	LEF B	0	50	7	$67
HARGIS	LEF B	0	23	23	$73
PETRO PARDS	LEF B	0	119	76	$75
	Total		294	144	

Asset Level Cash Flow



Note: Maverick asset is largely exploratory with minimal activity in the last year and type curves would need further risking if considering development.

IV. Midstream

Illustrative Catarina Marketing Diagram

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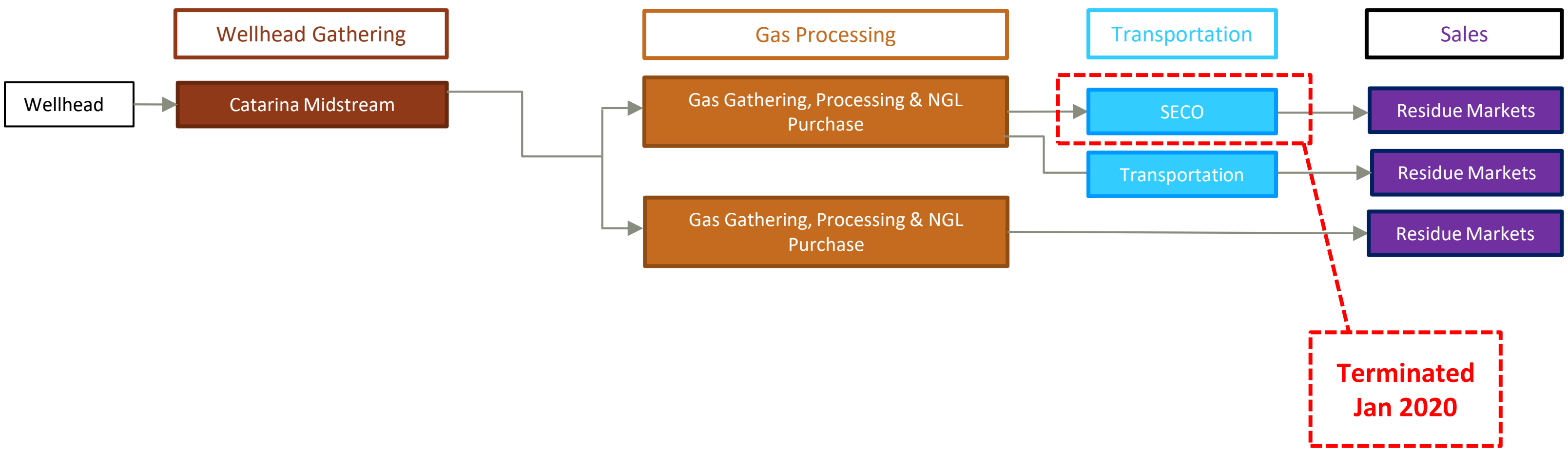
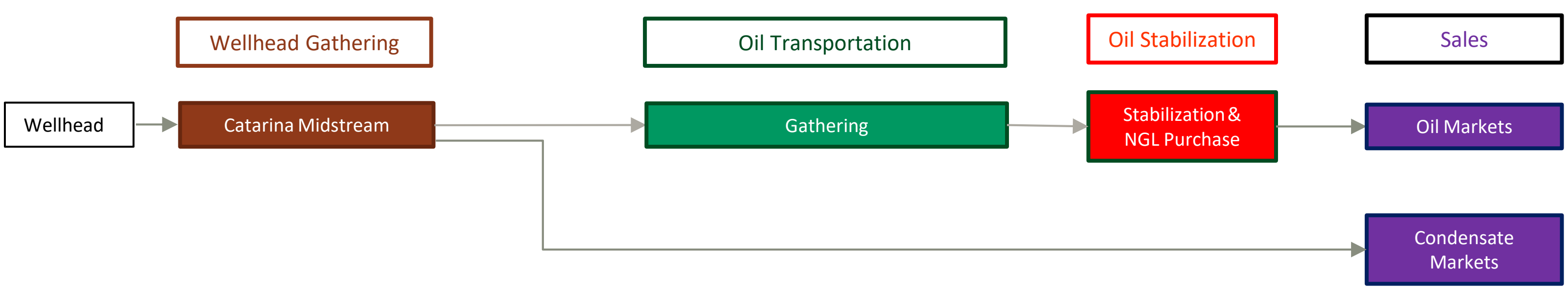
Diagrams below represent the flow of hydrocarbons from Catarina

Gas Marketing



Oil Marketing



Illustrative Comanche Marketing Diagram

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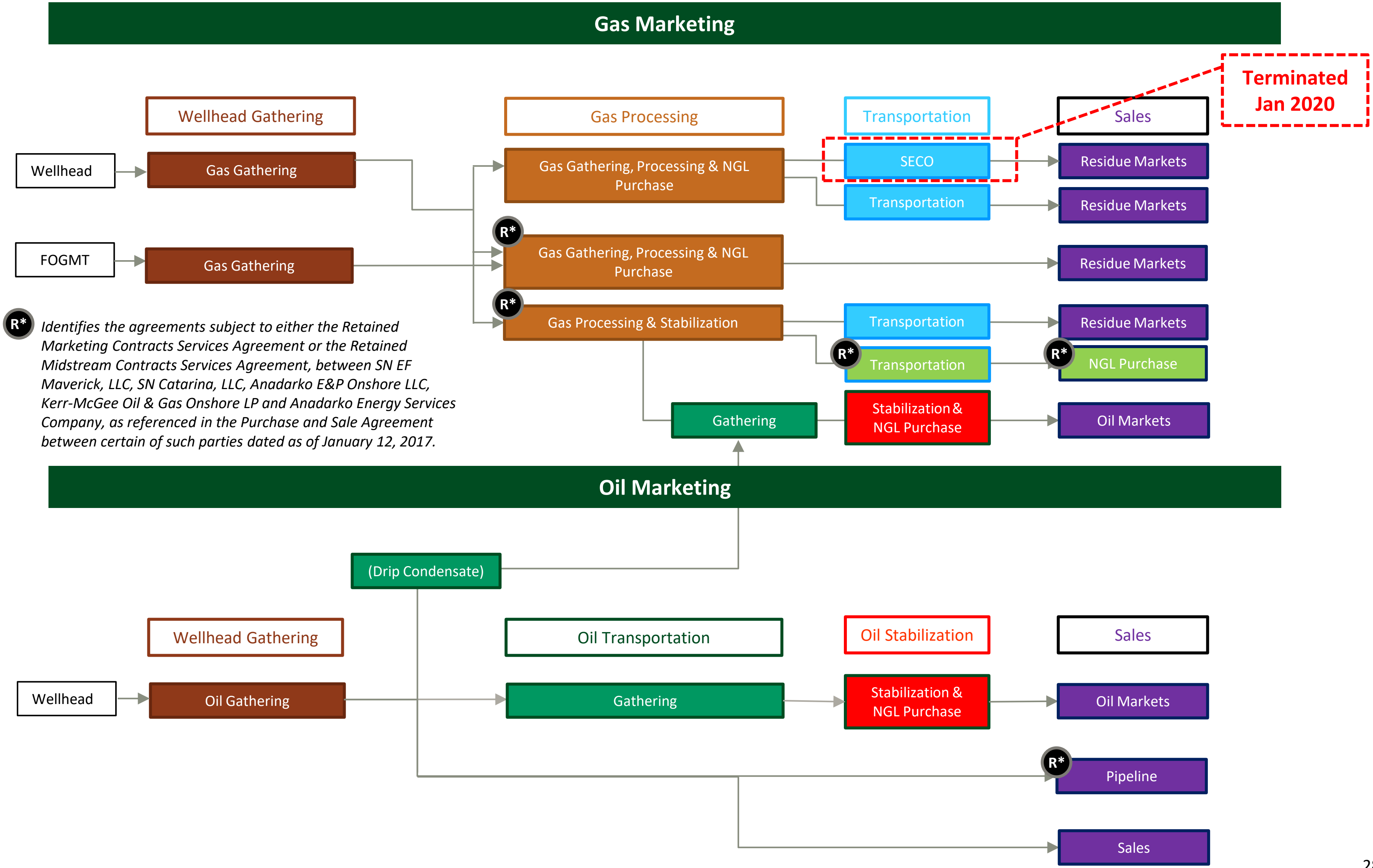
Diagrams below represent the flow of hydrocarbons from Comanche



V. Corporate G&A

COPAS Overview

General Summary

- The Council of Petroleum Accountants Societies ("COPAS") is a non-profit professional organization established in 1961 that outlines accounting guidelines and practices within the North American petroleum industry
- Base overhead rates that an operator can charge out to working interest partners must be agreed upon in the various Joint Operating Agreements ("JOA") between SN and its various counterparties. However, COPAS accounting procedures provide for the annual adjustment of the fixed rate overhead for drilling and producing wells
- COPAS does not publish or recommend any specific overhead rates or overhead surveys, as the rates are derived through negotiation among the parties to an agreement

COPAS at SN

- JOAs that SN is party to are subject to the adjustment rates that COPAS releases on an annual basis
- With SN being the operator of the Comanche assets, SN is able to charge the other working interest partners monthly
- The amounts that SN can charge out to working interest parties depend entirely on the well count, irrespective of changes in the Company's expenses
- A charge to the Company's working interest partners is reflected as a credit to G&A on SN's books and records

COPAS in Business Plan Model

- The business plan forecast calculates the average of the last 10 years of rate adjustments released by COPAS, which is approximately 3%
- The current average amount that SN is able to charge out to working interest partners is $950 per well, each month
- Beginning with the $950 monthly rate per well, the model assumes that the chargeable rate will increase at ~3% annually, as in the last ten years
- In a blowdown scenario where SN gives up operatorship, SN would then incur an additional expense per the JOA, instead of a receipt

Appendix

A. PDP Reference Case

PDP Reference Case: Historical and Financial Projections (Accrual)

$ millions	2017A	2018A	2019E[1]	*Pre-Emergence Jan-May* 2020E	*Post-Emergence Jun-Dec* 2020E	*Full Year* 2020E	2021E	2022E	2023E	2024E
Oil (Boe/d)	15,085	18,026	14,949	11,374	12,941	12,259	9,724	7,243	5,958	5,125
Gas (Mcf/d)	104,638	105,400	89,143	72,109	79,748	76,379	63,919	50,995	43,261	37,926
NGL (Boe/d)	15,171	18,762	15,829	13,511	14,916	14,296	11,999	9,562	8,105	7,101
Total Net Daily Production (Boe/d)	**47,695**	**54,355**	**45,635**	**36,903**	**41,149**	**39,285**	**32,376**	**25,304**	**21,273**	**18,547**
Benchmark Commodity Prices:										
WTI ($/Bbl)	$50.97	$64.66	$57.02	$51.65	$51.00	$51.27	$50.89	$50.96	$51.32	$51.69
Henry Hub ($/Mcf)	$3.11	$3.11	$2.60	$1.87	$2.13	$2.02	$2.36	$2.41	$2.45	$2.47
Mt. Belvieu Propane ($/Bbl)	$20.48	$23.45	$22.46	$16.36	$17.86	$17.24	$18.45	$18.93	$19.30	$19.43
Realized Commodity Prices:										
Oil ($/Bbl)	$49.47	$65.73	$56.34	$49.48	$48.55	$48.90	$48.64	$48.68	$49.00	$49.35
Gas ($/Mcf)	$3.17	$3.14	$2.67	$1.85	$2.11	$2.01	$2.34	$2.39	$2.43	$2.45
NGL ($/Bbl)	$21.10	$23.39	$14.09	$8.33	$9.10	$8.80	$9.34	$9.60	$9.80	$9.88
Oil Revenue	$272	$432	$307	$85	$134	$219	$173	$129	$107	$93
Gas Revenue	121	121	87	20	36	56	55	45	38	34
NGL Revenue	117	160	81	17	29	46	41	34	29	26
Other Sales and Marketing Revenue	---	26	18	---	---	---	---	---	---	---
Oil, Gas, & NGL Revenue	**$510**	**$739**	**$494**	**$122**	**$199**	**$322**	**$268**	**$207**	**$174**	**$152**
Hedge Gain / (Loss)	$5	$(86)	$8	$ ---	$ ---	$ ---	$ ---	$ ---	$ ---	$ ---
Other Sales and Marketing Expenses	---	(24)	(17)	---	---	---	---	---	---	---
Lease Operating Expenses	(49)	(64)	(43)	(13)	(19)	(32)	(30)	(29)	(27)	(27)
Marketing	(108)	(131)	(160)	(58)	(91)	(149)	(131)	(108)	(89)	(78)
Production Taxes	(18)	(30)	(18)	(5)	(8)	(13)	(11)	(8)	(7)	(6)
Ad Valorem Taxes	(5)	(10)	(10)	(3)	(4)	(7)	(6)	(4)	(4)	(3)
Corporate G&A	(114)	(87)	(89)	(26)	(25)	(51)	(17)	(17)	(18)	(18)
Restructuring & Chapter 11 Fees	---	---	(83)	(61)	---	(61)	---	---	---	---
Total G&A	(114)	(87)	(173)	(86)	(25)	(111)	(17)	(17)	(18)	(18)
Reconciling Items to EBITDAX [2]	28	(6)	87	61	---	61	---	---	---	---
Adjusted EBITDAX	**$249**	**$302**	**$167**	**$18**	**$52**	**$70**	**$74**	**$40**	**$29**	**$20**
EBITDA Margin (%)	*49%*	*41%*	*34%*	*15%*	*26%*	*22%*	*27%*	*19%*	*17%*	*13%*
Memo: Total Operating Expenses	*$(261)*	*$(437)*	*$(327)*	*$(104)*	*$(148)*	*$(252)*	*$(194)*	*$(167)*	*$(145)*	*$(132)*
Capex	$(485)	$(512)	$(62)	$(97)	$(27)	$(124)	$(12)	$(1)	$(1)	$(1)
Adjusted EBITDAX Less Capex	**$(236)**	**$(210)**	**$105**	**$(79)**	**$25**	**$(54)**	**$62**	**$39**	**$28**	**$19**
Restructuring & Chapter 11 Fees	$ ---	$ ---	$(83)	$(61)	$ ---	$(61)	$ ---	$ ---	$ ---	$ ---
Unlevered Cash Flow (after Ch. 11 Fees)	**$(236)**	**$(210)**	**$21**	**$(139)**	**$25**	**$(115)**	**$62**	**$39**	**$28**	**$19**
Memo: Catarina Central / East Volumes (Boe/d) [3]						*13,779*	*10,754*	*8,431*	*7,073*	*6,127*
Memo: COPAS Recovery/(Payment) - 3rd Parties	*$11*	*$19*	*$16*	*$6*	*$(1)*	*$5*	*$(5)*	*$(5)*	*$(6)*	*$(6)*
Memo: COPAS Recovery/(Payment) - UnSub	*$2*	*$4*	*$4*	*$2*	*$3*	*$4*	*$5*	*$5*	*$5*	*$5*

Notes: Represents consolidated cash flow forecast net to Debtors. Presented on an accrual basis. Strip pricing as of 2/11/20.

(1) Q4 2019 quarter actuals are estimates and subject to change upon finalized earnings.

(2) Represents non-cash, non-recurring and other amounts included in the above line items which are traditionally added back or excluded in the determination of Adjusted EBITDAX. The amount primarily reflects restructuring fees and certain non-cash adjustments.

(3) Production volumes from ARIES database may not tie exactly to the company model.

B. Other Supporting Items

Historical EBITDAX Reconciliation – Restricted Group

(In Thousands)	2017 Consolidated SN FY	2017 Restricted Group (Model) FY	2018 Consolidated SN FY	2018 Restricted Group (Model) FY
Adjusted EBITDAX:				
Net income (loss)	$ 43,191	$ (6,851)	$ 85,205	$ (22,501)
Adjusted by:				
Interest expense	128,189	120,550	165,233	156,398
Amortization of debt costs [1]	11,975	8,880	12,625	8,819
Net losses (gains) on commodity derivative contracts [2]	6,099	7,986	27,756	32,316
Net settlements paid on commodity derivative contracts	13,140	670	(103,205)	(81,141)
Exploration expense	5,755	5,755	3,295	3,284
Depreciation, depletion, amortization and accretion [1]	177,153	125,696	262,481	197,388
Impairment of oil and natural gas properties [1]	39,499	39,499	14,386	14,337
Stock-based compensation [1]	22,909	22,909	792	792
Acquisition and divestiture costs included in G&A	30,526	30,334	778	778
Income tax expense (benefit)	(2,336)	(2,336)	-	-
Gains on sale of oil and natural gas properties	-	-	(1,528)	(1,528)
Gains on disposal of assets	(81,955)	(81,955)	-	-
Loss on impairment of other assets	-	-	-	-
Impairment of right of use assets	-	-	-	-
Accrued amount for executive bonuses included in G&A	-	-	-	-
(Gains) losses on embedded derivatives	1,551	1,551	(700)	(700)
(Gains) losses on investments	871	871	21,798	21,798
Amortization of deferred gain on Catarina Midstream sale	(23,718)	(23,718)	(23,720)	(23,720)
Interest income	(836)	(836)	(4,351)	(4,351)
Adjusted EBITDAX	**$ 372,013**	**$ 249,004**	**$ 460,845**	**$ 301,969**

(1) Represent non-cash adjustments to net income.
(2) Includes cash received and non-cash (gains) losses.

Business Plan Assumptions (Option Preservation Case)

Pricing *(As of 2/11/20)*

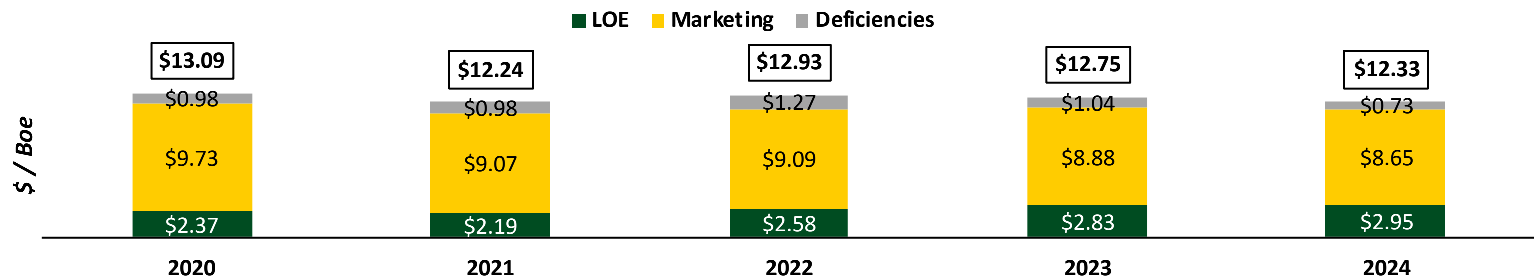
Strip	2020	2021	2022	2023	2024
WTI Oil ($/Bbl)	$51.27	$50.89	$50.96	$51.32	$51.69
Henry Hub Gas ($/MMBtu)	$2.02	$2.36	$2.41	$2.45	$2.47
Mt. Belvieu Propane ($/Bbl)	$17.24	$18.45	$18.93	$19.30	$19.43

Commodity Price Realizations

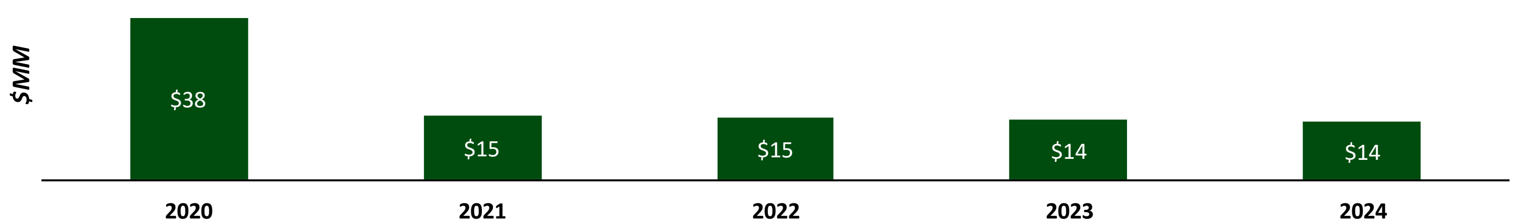
- Differentials have been developed by asset area based on historical 12-month average as compared to current futures pricing and relevant contract changes.

Realizations	Catarina	Comanche	Maverick	Palmetto	OBO	SR	TMS
Oil (% WTI)	93%	98%	99%	105%	103%	109%	105%
Gas (% Henry Hub)	99%	100%	100%	103%	62%	100%	100%
NGL (% Mt B Propane)	52%	43%	69%	63%	62%	-	-

Lease Operating Expense



G&A



Note: Strip pricing sourced from Capital IQ as of 2/11/20.

Business Plan Assumptions (Option Preservation Case)

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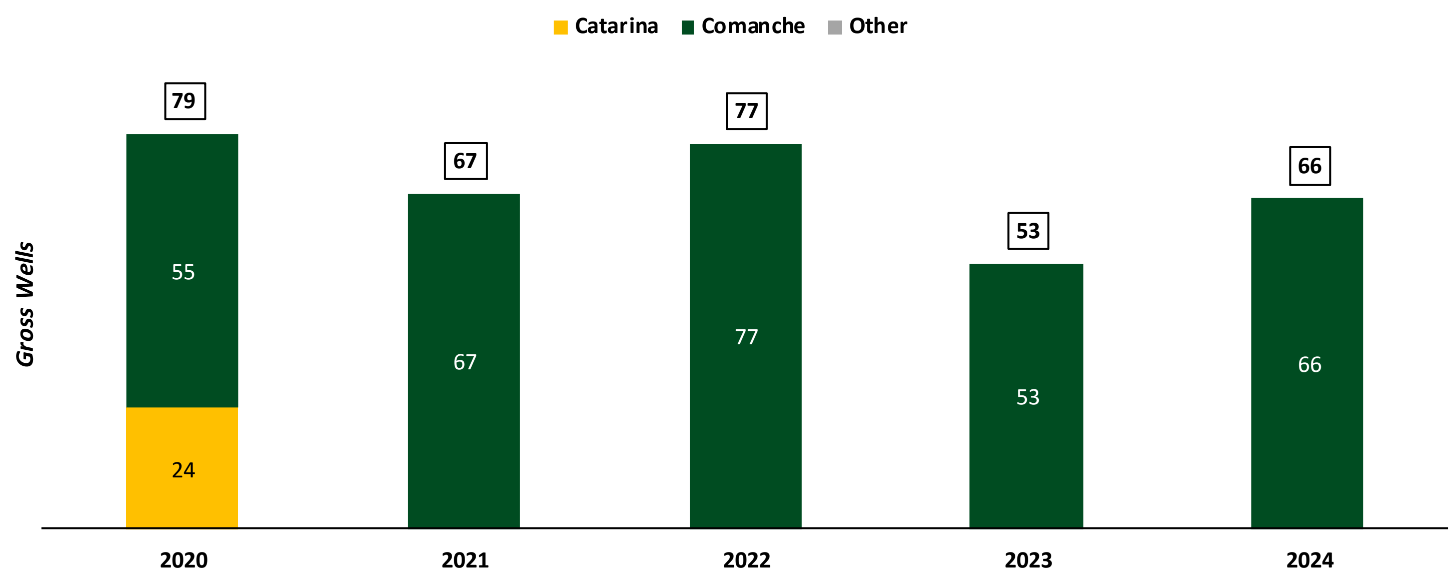
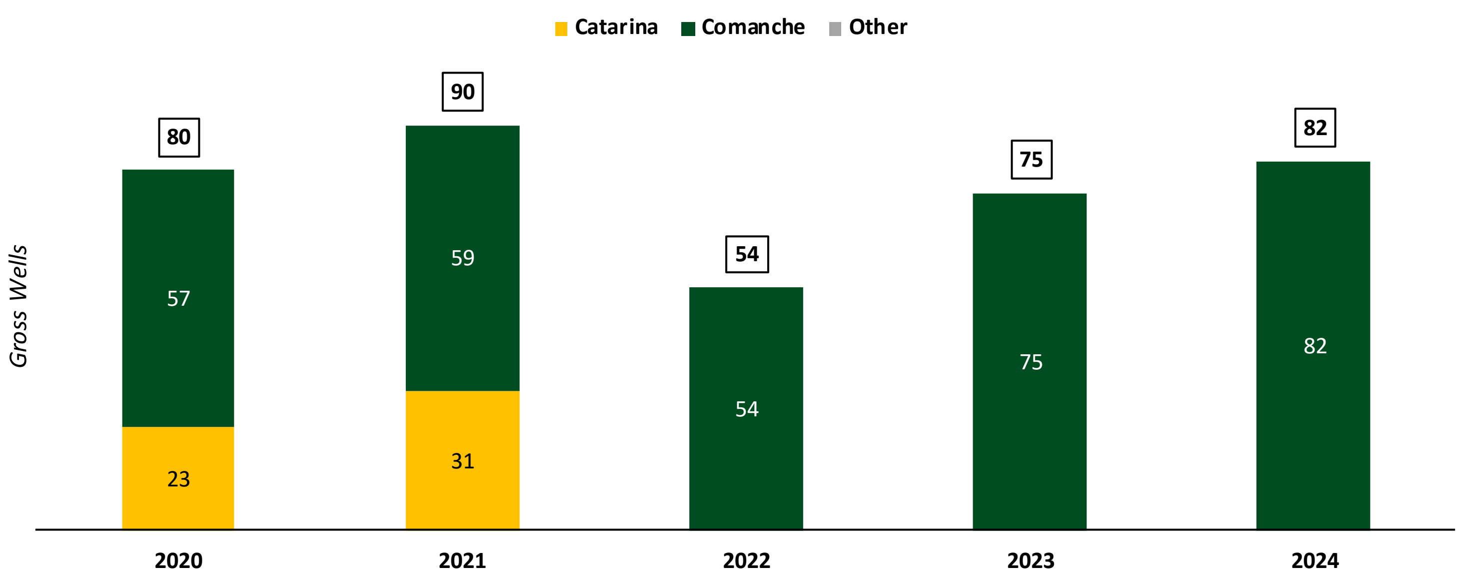
Drilling Activity (SPUD)

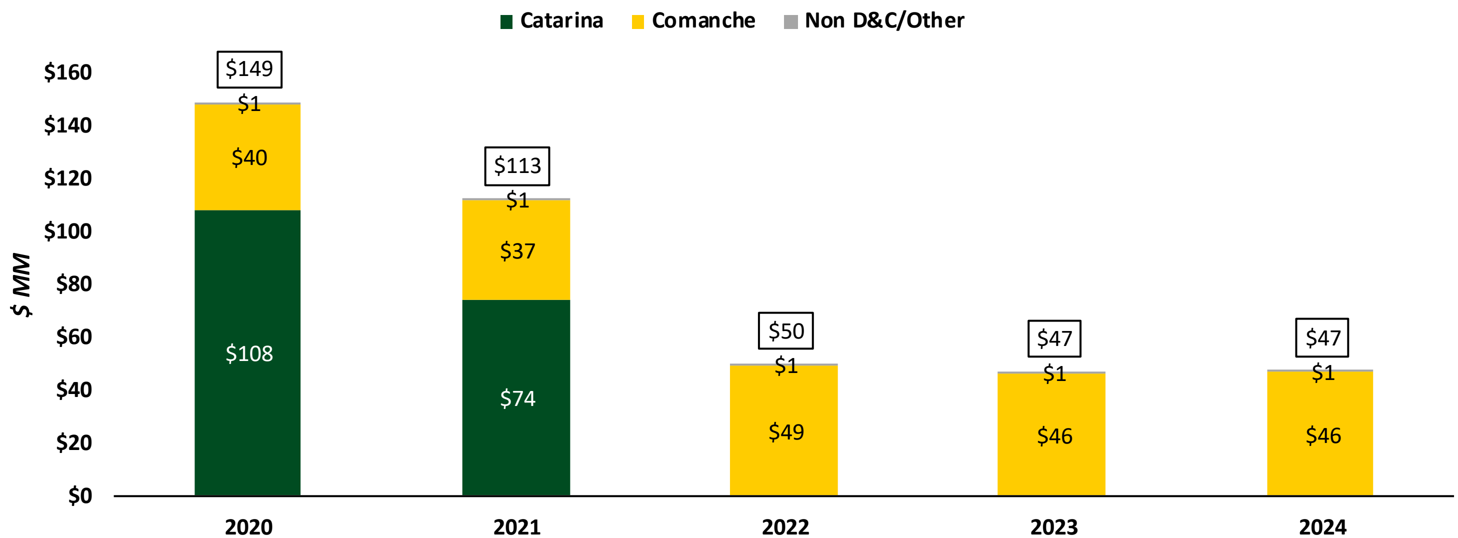


Completion Activity (TTP)

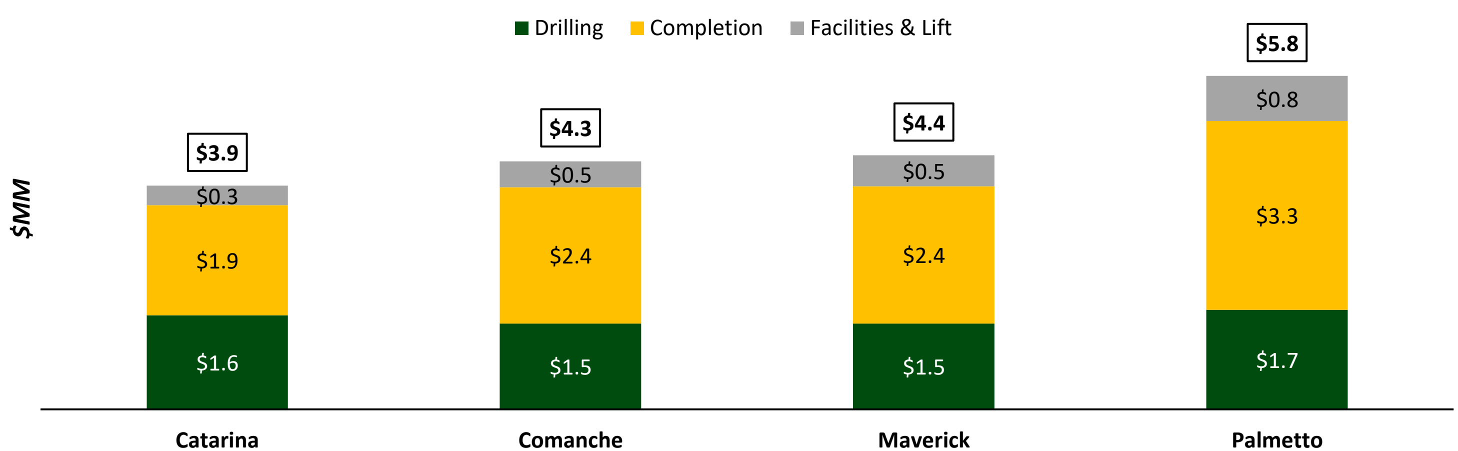


Business Plan Assumptions (Option Preservation Case)

Capital Expenditures



Well Costs(1)



Note:
(1) Presented well costs are based on an average 6,000 ft lateral, but each well is adjusted based off its exact lateral length in all financial forecasts.

Business Plan Assumptions (Accelerated Completions Case)

Pricing *(As of 2/11/20)*

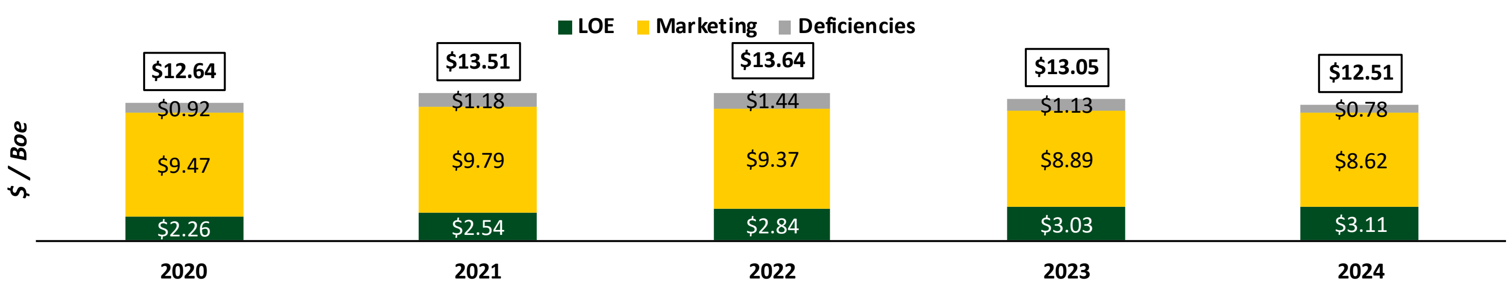
Strip	2020	2021	2022	2023	2024
WTI Oil ($/Bbl)	$51.27	$50.89	$50.96	$51.32	$51.69
Henry Hub Gas ($/MMBtu)	$2.02	$2.36	$2.41	$2.45	$2.47
Mt. Belvieu Propane ($/Bbl)	$17.24	$18.45	$18.93	$19.30	$19.43

Commodity Price Realizations

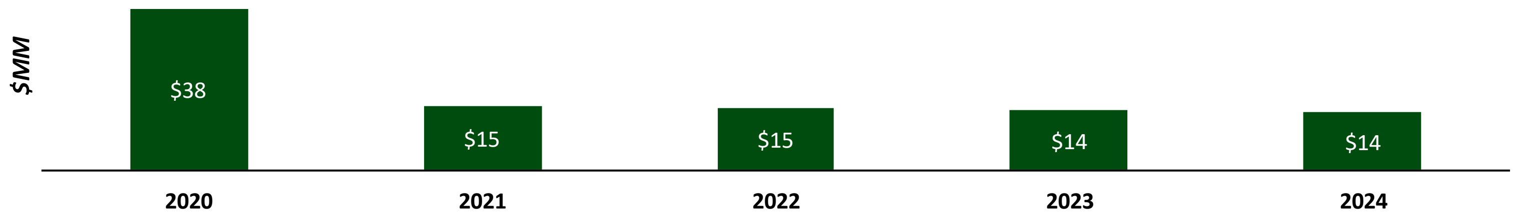
- Differentials have been developed by asset area based on historical 12-month average as compared to current futures pricing and relevant contract changes.

Realizations	Catarina	Comanche	Maverick	Palmetto	OBO	SR	TMS
Oil (% WTI)	93%	98%	99%	105%	103%	109%	105%
Gas (% Henry Hub)	99%	100%	100%	103%	62%	100%	100%
NGL (% Mt B Propane)	52%	43%	69%	63%	62%	-	-

Lease Operating Expense



G&A



Note: Strip pricing sourced from Capital IQ as of 2/11/20.

Business Plan Assumptions (Accelerated Completions Case)

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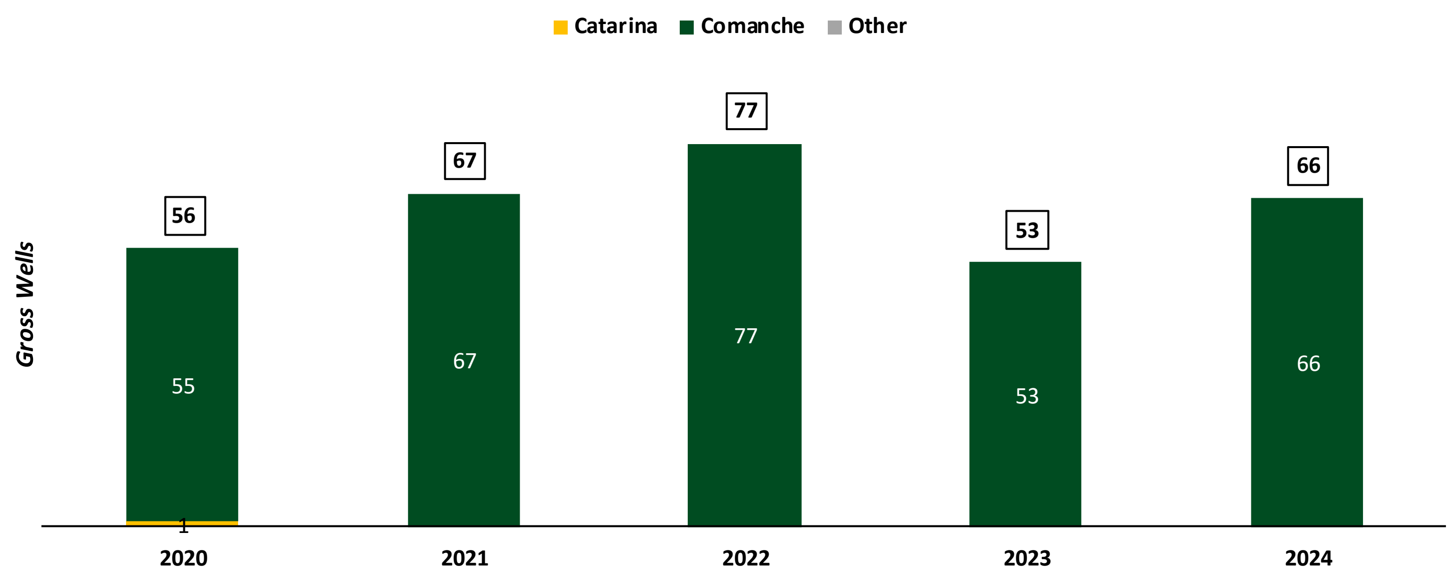
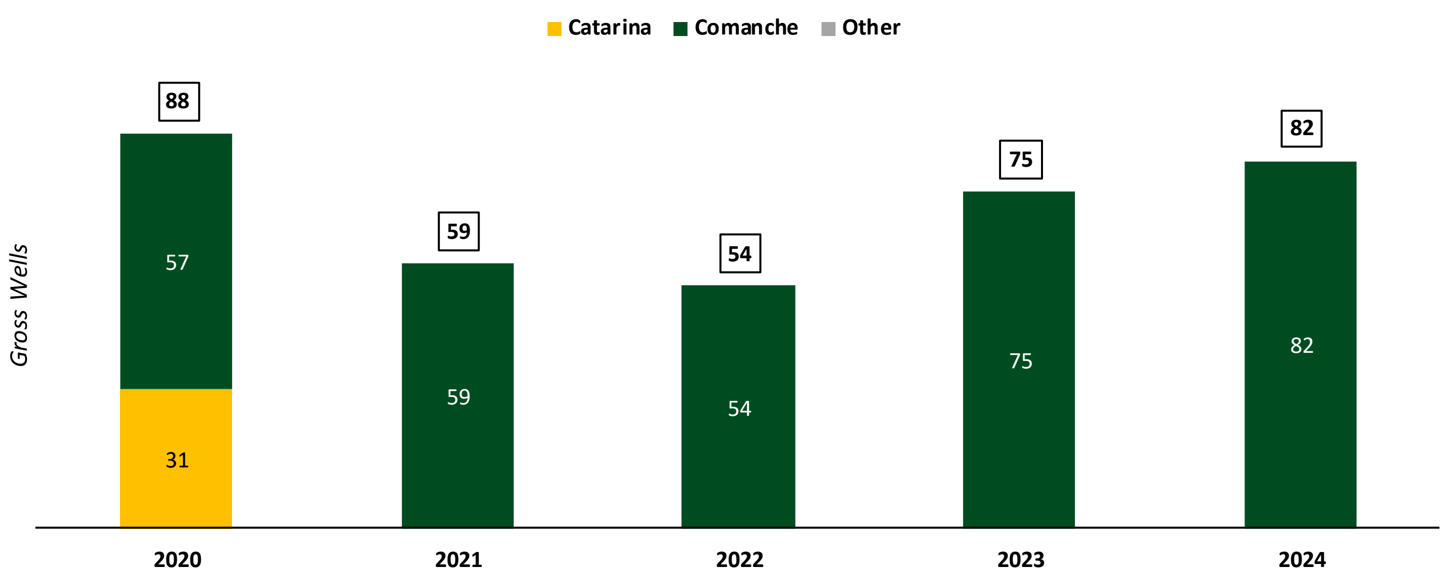
Drilling Activity (SPUD)



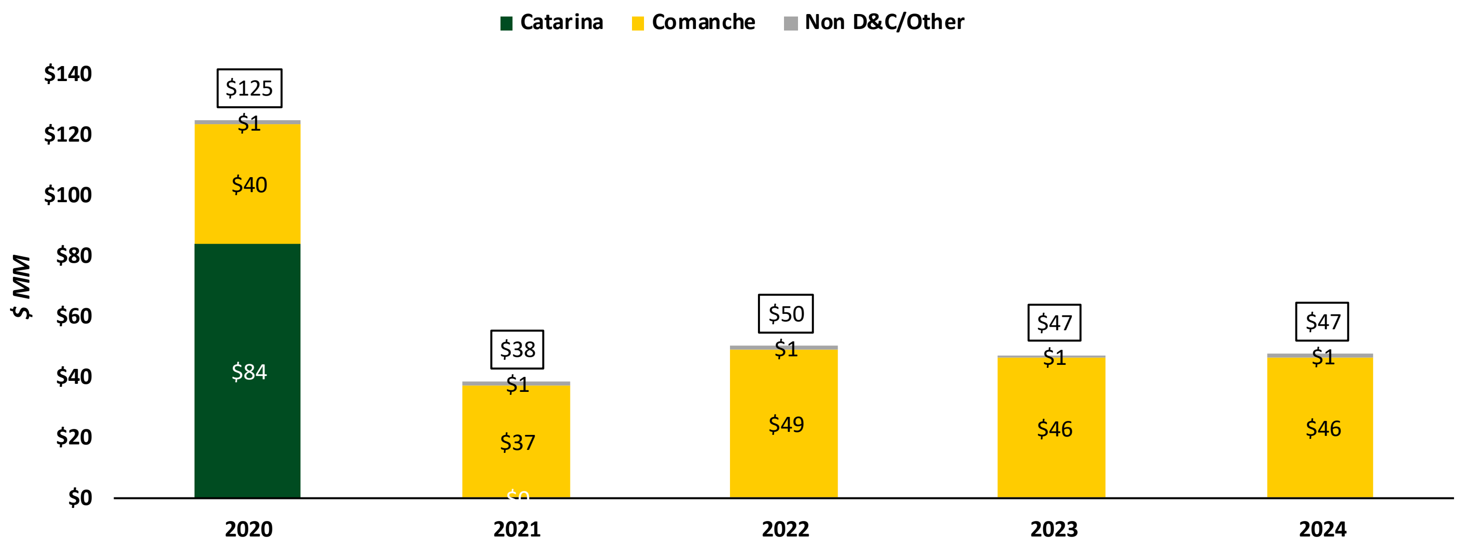
Completion Activity (TTP)



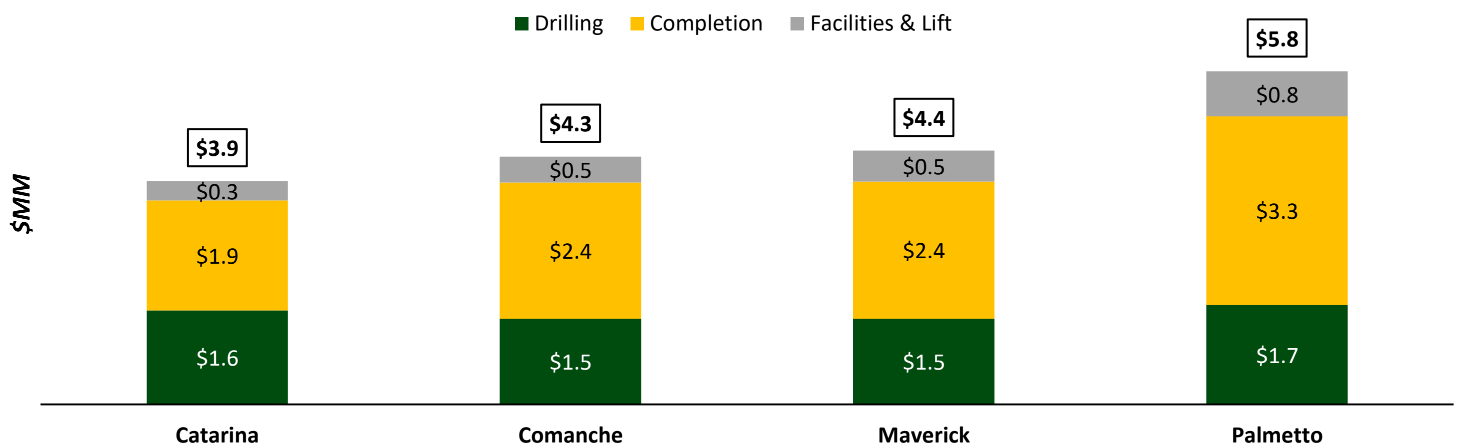
Note: In comparison, PDP reference case drilling and completion activity is comprised of the following: Drilling – 1 well in Catarina (2020), 66 wells in Comanche (55 in 2020 and 11 in 2021), Completions - 31 wells in Catarina (all in 2020), 80 wells in Comanche (57 in 2020 and 23 in 2021)

Business Plan Assumptions (Accelerated Completions Case)

Capital Expenditures



Well Costs[1]



Note:
(1) Presented well costs are based on an average 6,000 ft lateral, but each well is adjusted based off its exact lateral length in all financial forecasts.

Forecast Liquidity

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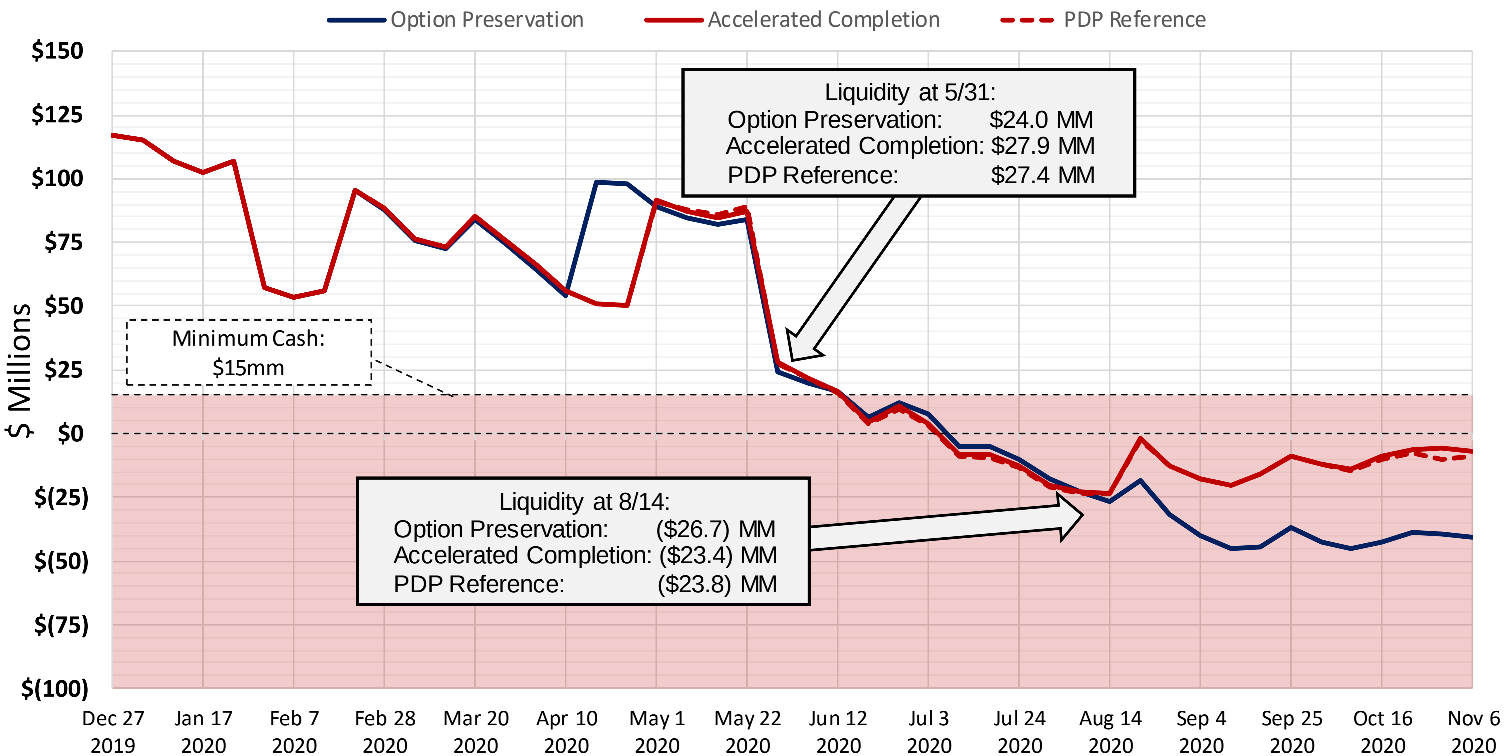
Similar Liquidity Profile at Exit in Option Preservation, Accelerated Completions, and PDP Reference Scenarios



**PDP Reference scenario does not assume full conversion to non-operated cash based forecast*

- Liquidity at 5/31/2020 of $24.0MM in the Option Preservation scenario, $27.9MM in the Accelerated Completion scenario, and $27.4MM in a PDP Reference scenario.
- Cash Flows include:
  - Payment of accrued DIP interest at 5/31/2020 and exit fees of 1.5% of total new money commitment (~$1.8MM)
  - 1L adequate protection paid during case ($36MM) and accrued adequate protection paid on 5/31/2020 ($9.4MM)
  - Payment of all accrued & unpaid professional fees and success fees (~38.3MM)
- DIP commitment is $150MM of new money and $50MM of 1st lien roll-up to be refinanced upon exit
- No additional disbursements associated with emergence are included in this forecast

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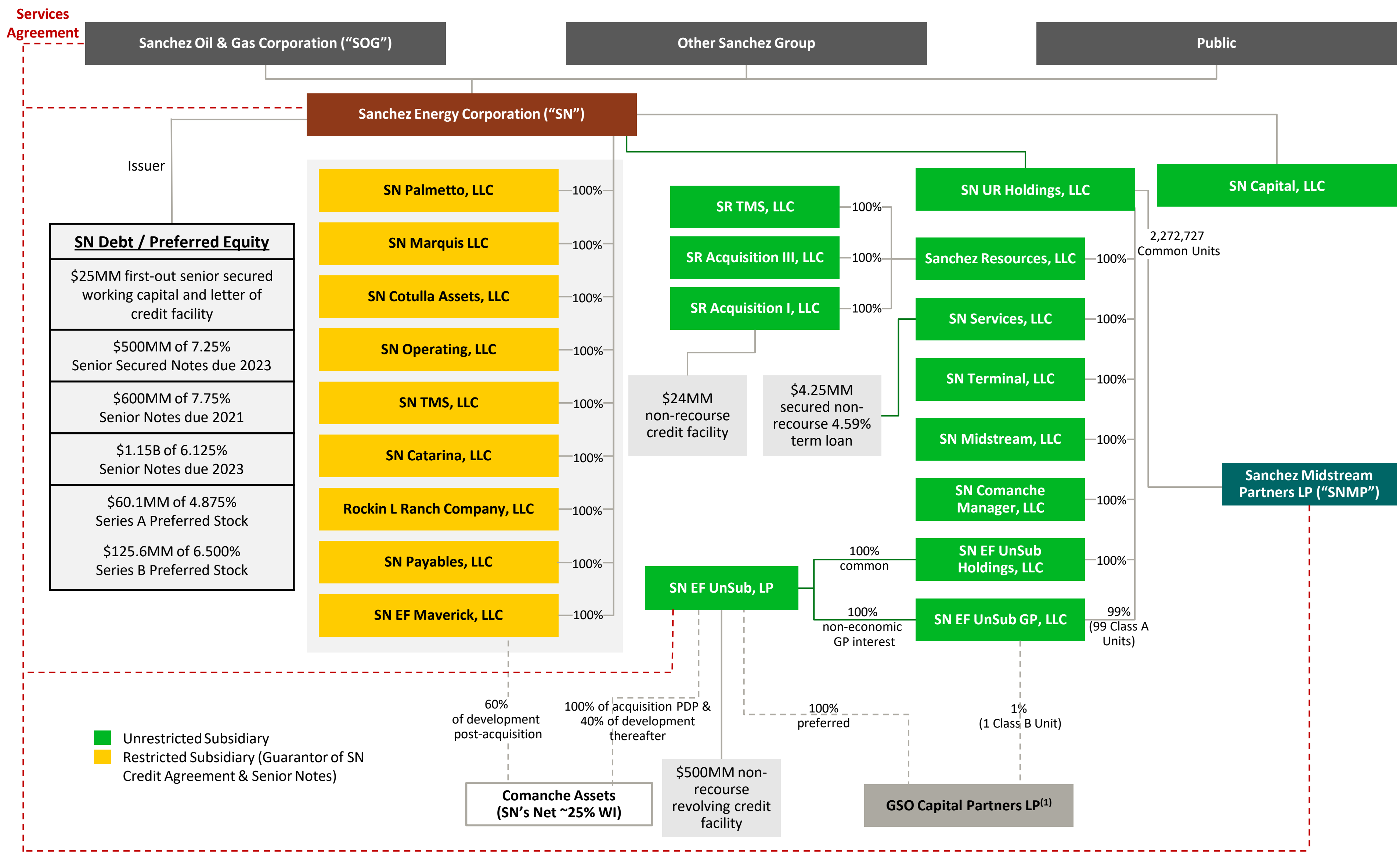
Sanchez Energy Organizational Structure (Pre-Petition)



Notes:

(1) GSO ST Holdings Associates LLC owns the Class B Unit in SN EF UnSub GP, LLC, which holds the GP interest in SN EF UnSub, LP. GSO ST Holdings LP owns 485,000 preferred units in SN EF UnSub, LP, and the remaining 15,000 preferred units in SN EF UnSub, LP are held by Intrepid Private Equity Fund I, LP and Intrepid Private Equity SPV-A, L.P.

Comanche Ownership Structure

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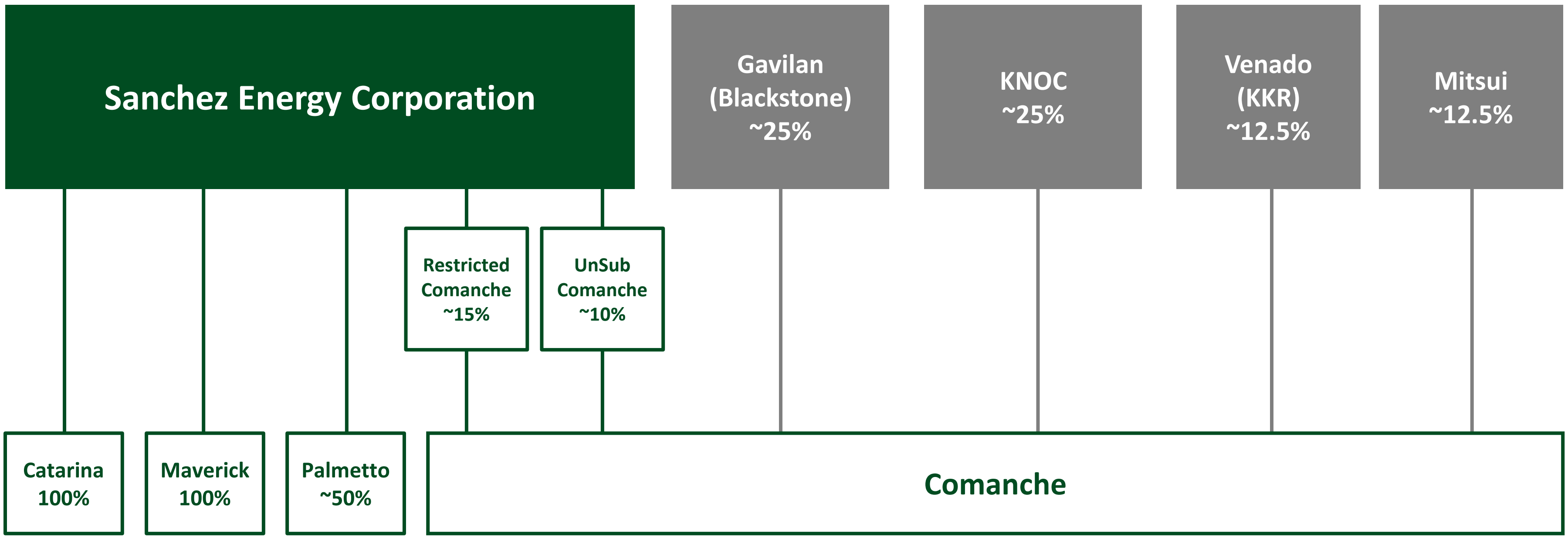

Note: Percentages shown represent interest in future development.

Annual NYMEX WTI Oil Strip Pricing

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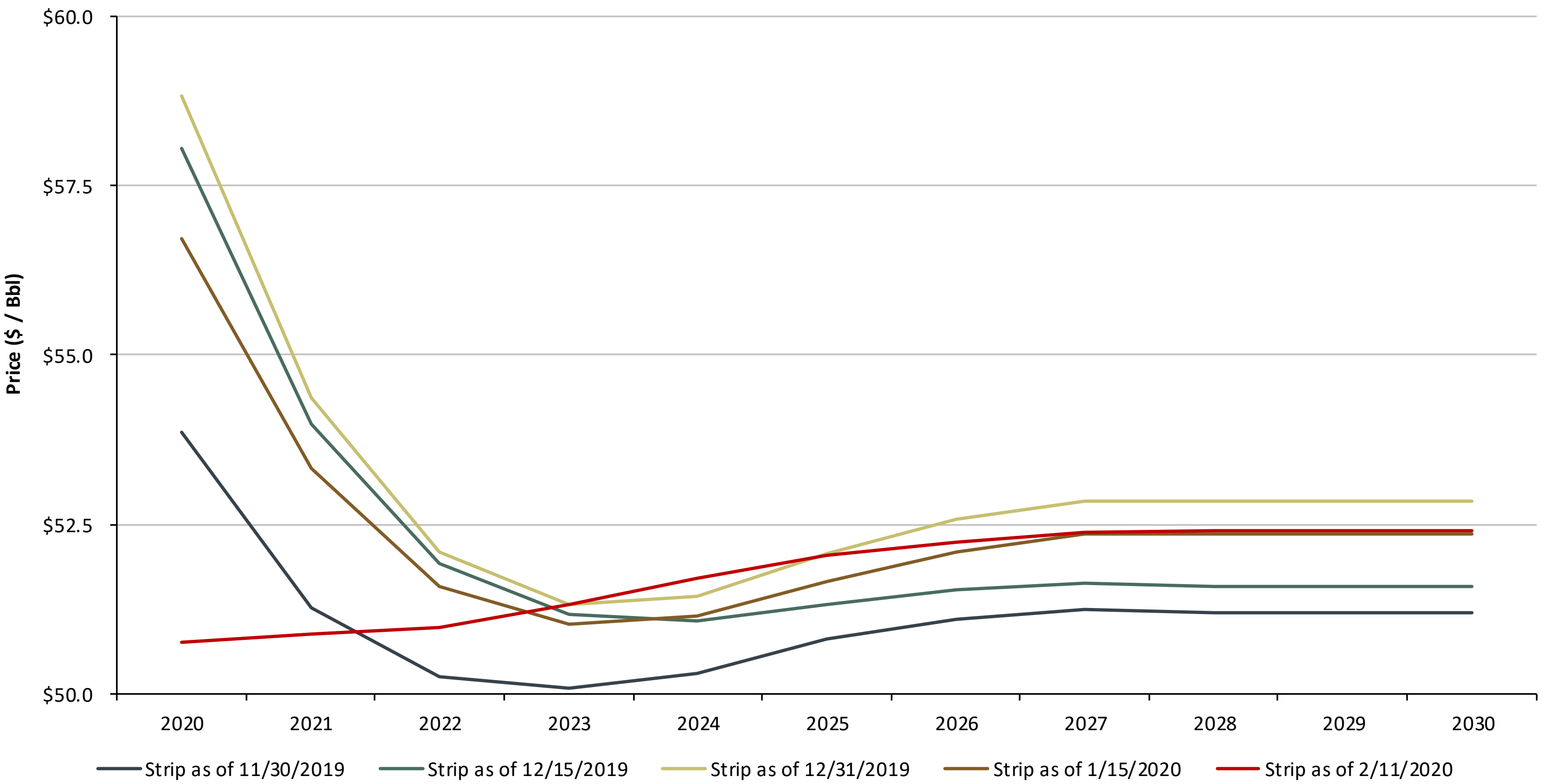
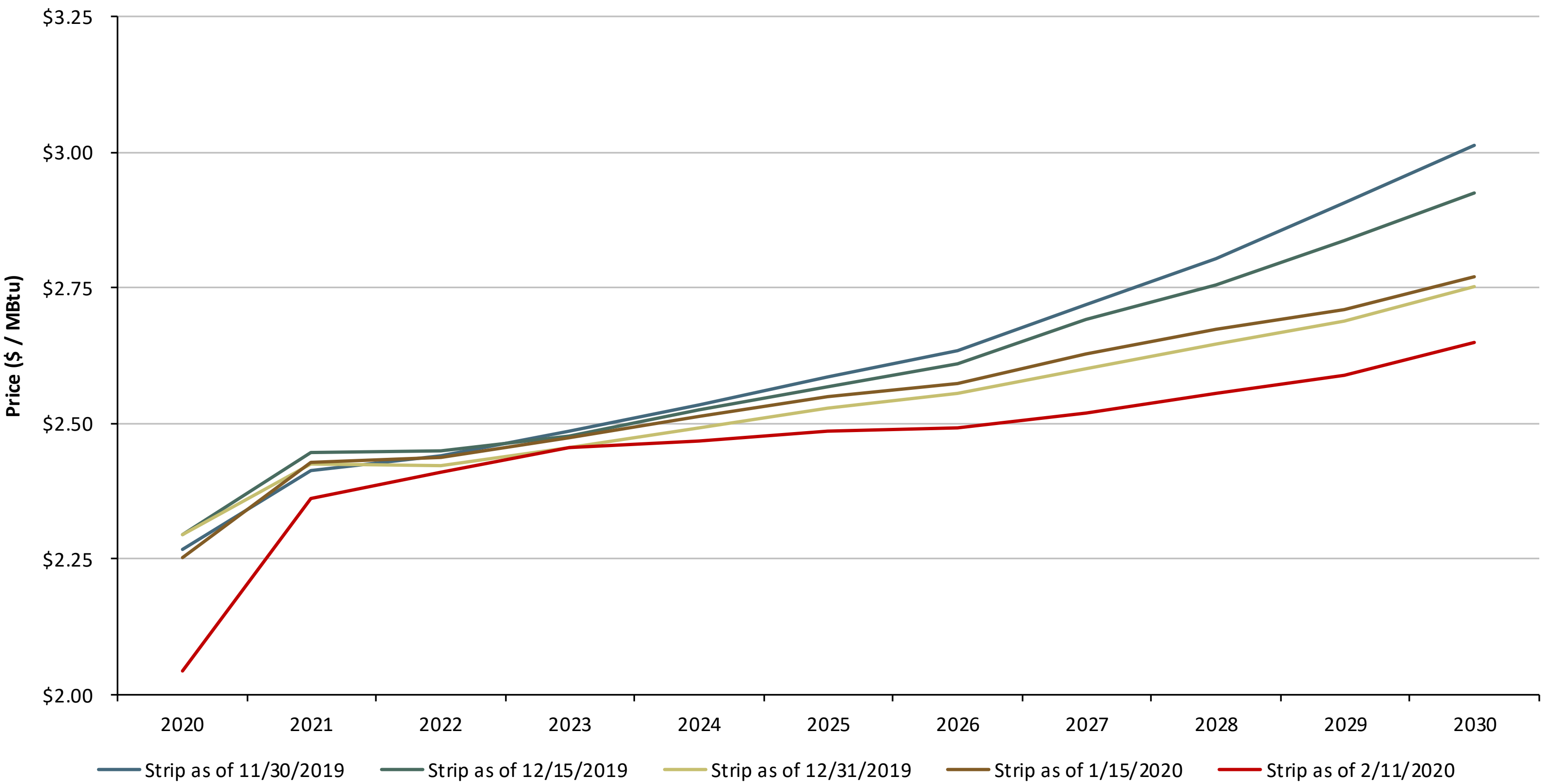


Annual Averages

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Strip as of 11/30/2019	$53.86	$51.26	$50.24	$50.07	$50.30	$50.79	$51.09	$51.24	$51.20	$51.20	$51.20
Strip as of 12/15/2019	$58.05	$53.99	$51.92	$51.16	$51.08	$51.32	$51.52	$51.62	$51.58	$51.58	$51.58
Strip as of 12/31/2019	$58.83	$54.38	$52.09	$51.31	$51.44	$52.07	$52.57	$52.84	$52.84	$52.84	$52.84
Strip as of 1/15/2020	$56.71	$53.33	$51.57	$51.01	$51.15	$51.66	$52.09	$52.34	$52.36	$52.36	$52.36
Strip as of 2/11/2020	$50.76	$50.89	$50.96	$51.32	$51.69	$52.04	$52.22	$52.38	$52.40	$52.40	$52.40

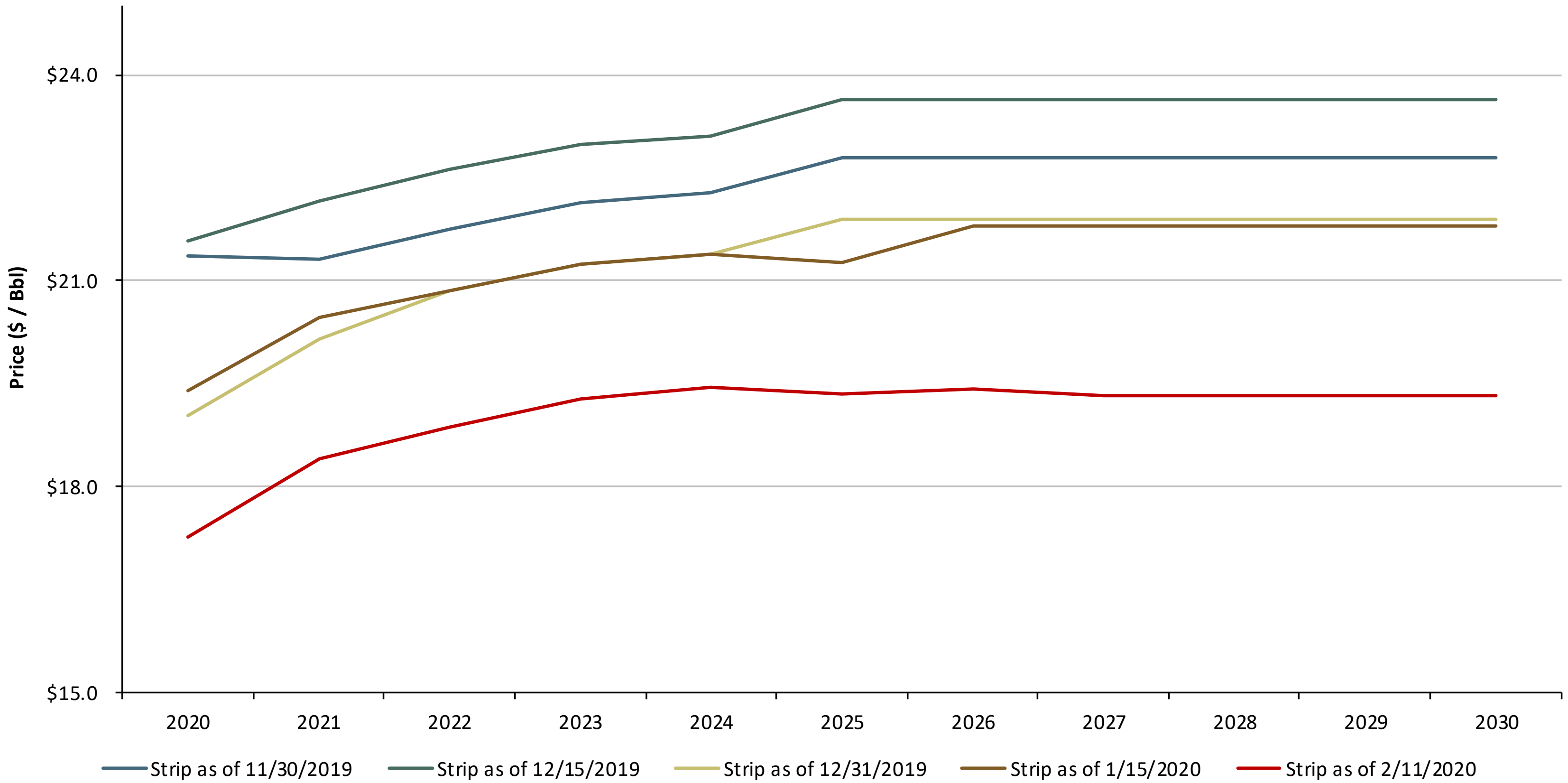
Annual NYMEX Henry Hub Gas Strip Pricing



Annual Averages

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Strip as of 11/30/2019	$2.27	$2.41	$2.44	$2.48	$2.54	$2.58	$2.63	$2.72	$2.80	$2.91	$3.01
Strip as of 12/15/2019	$2.29	$2.45	$2.45	$2.48	$2.52	$2.57	$2.61	$2.69	$2.75	$2.84	$2.92
Strip as of 12/31/2019	$2.29	$2.42	$2.42	$2.46	$2.49	$2.53	$2.55	$2.60	$2.65	$2.69	$2.75
Strip as of 1/15/2020	$2.25	$2.43	$2.44	$2.47	$2.51	$2.55	$2.57	$2.63	$2.67	$2.71	$2.77
Strip as of 2/11/2020	$2.04	$2.36	$2.41	$2.45	$2.47	$2.49	$2.49	$2.52	$2.55	$2.59	$2.65

Annual Mt. Belvieu Propane Strip Pricing



Annual Averages

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Strip as of 11/30/2019	$21.35	$21.31	$21.75	$22.13	$22.27	$22.79	$22.79	$22.79	$22.79	$22.79	$22.79
Strip as of 12/15/2019	$21.57	$22.15	$22.62	$22.97	$23.11	$23.63	$23.63	$23.63	$23.63	$23.63	$23.63
Strip as of 12/31/2019	$19.04	$20.16	$20.86	$21.24	$21.38	$21.89	$21.89	$21.89	$21.89	$21.89	$21.89
Strip as of 1/15/2020	$19.40	$20.45	$20.86	$21.24	$21.38	$21.27	$21.79	$21.79	$21.79	$21.79	$21.79
Strip as of 2/11/2020	$17.26	$18.39	$18.85	$19.27	$19.43	$19.35	$19.41	$19.33	$19.33	$19.33	$19.33