Levin College of Public Affairs and Education

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JOBSOHIO

SHALE INVESTMENT DASHBOARD IN OHIO Q1 AND Q2 2023

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Executive Summary

This report presents findings from an investigation into shale-related investment in Ohio. The investment estimates are cumulative from January through June of 2023. Prior investments have been included in previous reports that are available from Cleveland State University. [1] Subsequent reports will estimate additional investment since the date of this report. Investment in Ohio into the Utica during the first half of 2023 can be summarized as follows:

Total Estimated Upstream Utica Investment: January – June 2023

Lease Renewals and New Leases	$64,769,000
Drilling	$858,000,000
Roads	$12,765,000
Lease Operating Expenses	$194,321,567
Royalties	$763,815,000
Total Estimated Upstream Investment	**$1,893,670,567**

Total Estimated Midstream Investment: January – June 2023

Gathering Lines	$110,258,000
Gathering System Compression and Dehydration	$30,500,000
NGL Pipeline	$31,554,000
Total Estimated Midstream Investment	**$172,312,000**

Total Estimated Downstream Investment: January – June 2023

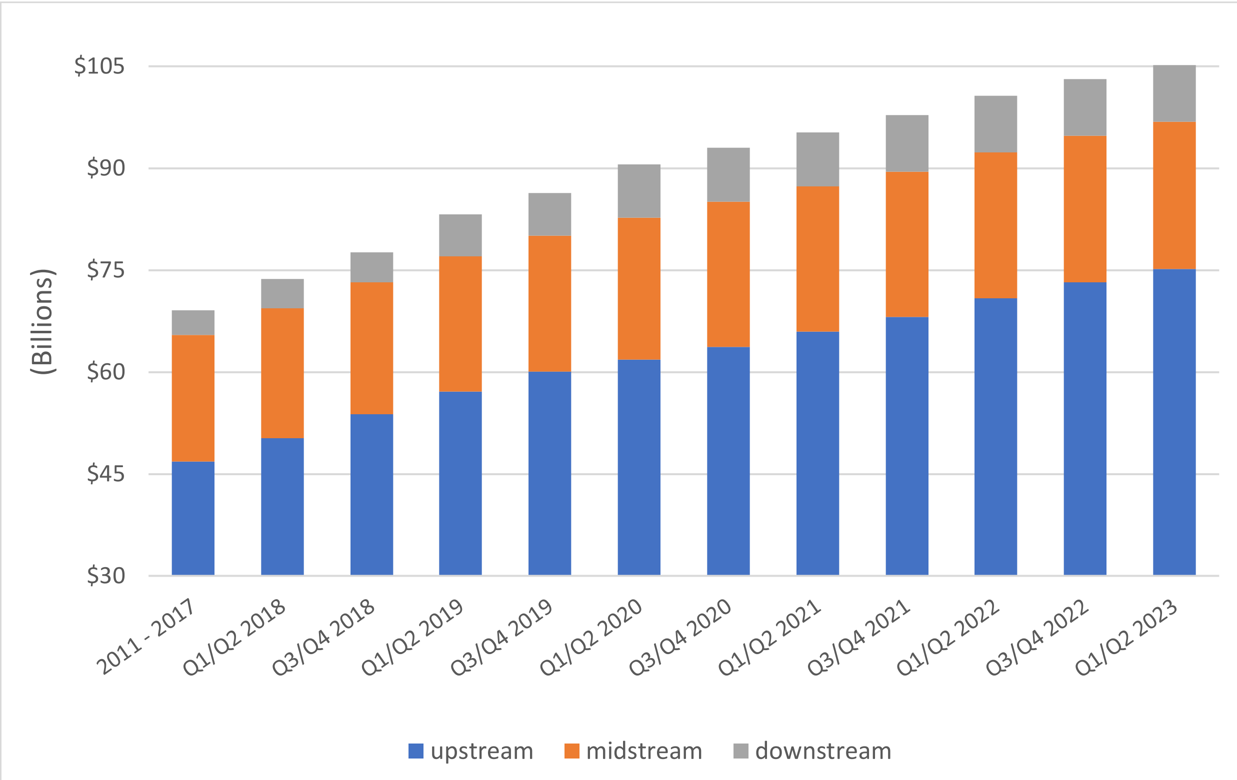
LPG Stations	$1,500,000
Total Estimated Downstream Investment	**$1,500,000**

Total investment from January through June 2023 was approximately $2.1 billion, including upstream, midstream, and downstream. Indirect downstream investment, such as development of new manufacturing as a result of lower energy costs, was not investigated as part of this Study. Together with previous investment to date, cumulative oil and gas investment in Ohio through June of 2023 is estimated to be around $105.2 billion. Of this, $75.1 billion has been in upstream, $21.7 billion in midstream, and $8.4 billion in downstream industries.[2] Figure 1 shows the growth in cumulative shale-related investment for Ohio since the release of the first Shale Dashboard.

[1] The fourteen previous reports on shale investment in Ohio up to December 2022 can be found at https://engagedscholarship.csuohio.edu/urban_enpolc/

[2] Numbers may not add up precisely due to rounding.

Figure 1: Cumulative Shale Investment in Ohio Over Time

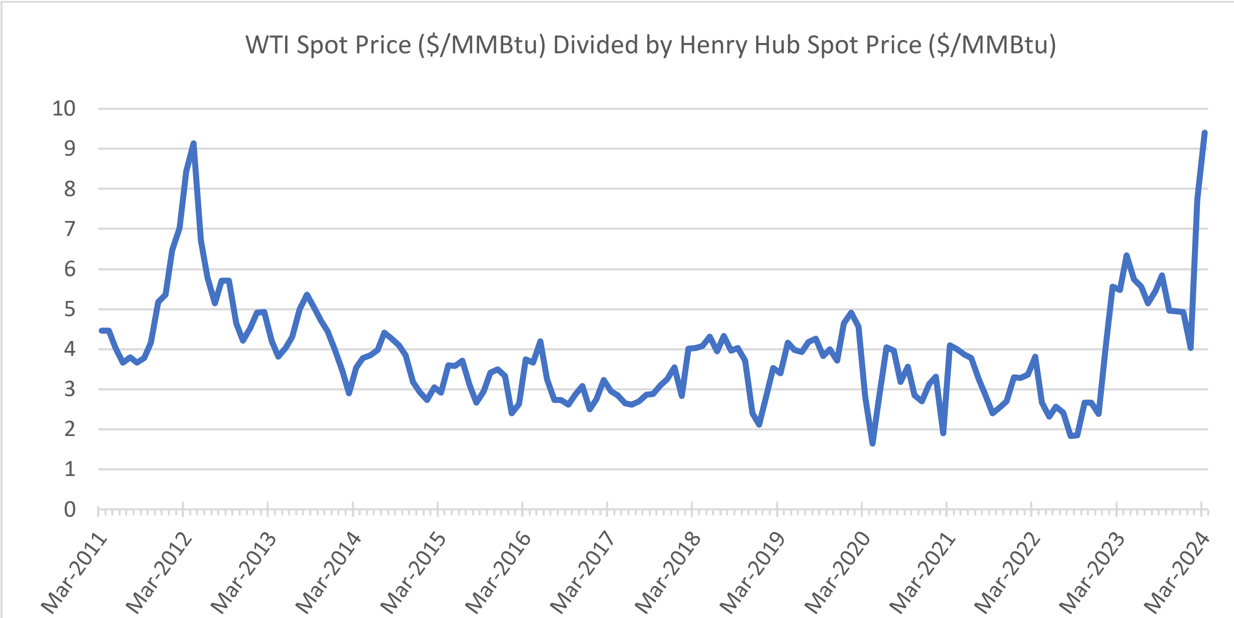


Overall upstream investments were down by about $481 million in the first half of 2023 compared to the second half of 2022. This decline was due almost entirely to lower natural gas prices that in turn resulted in lower royalties, as both the number of new wells drilled and production volumes increased in the first half of 2023 compared to the previous 6-month period.

A fall in natural gas prices to $2/MMBtu or less has been accompanied by rising oil prices that have consistently averaged around $80/bbl as of late.[3] This has led to sustained 10-year highs in the price ratio of oil to natural gas starting in 2023. (*See* Figure 2.) This oil-to-gas price ratio is driving the most important new trend in Ohio: an increase in drilling in predominantly oil producing regions of the Utica, which heretofore had been deemed less attractive than the predominantly gas producing regions.

[3] *See* EIA. (2024). *Henry Hub Natural Gas Spot Price*. https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm. *See also* EIA. (2024). *Cushing, OK WTI Spot Price FOB*. https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RWTC&f=M

Figure 2: Price Ratio of Crude Oil to Natural Gas ($/MMBtu Basis)

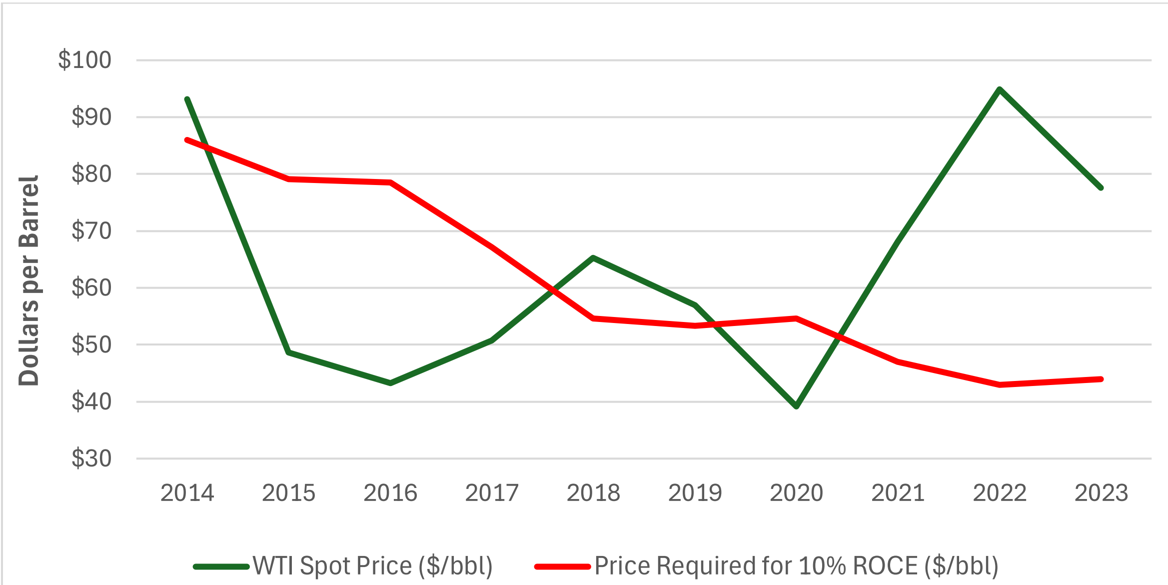


Data Source: EIA (2024). Assumes 5.8 MMBtu per barrel of crude oil.

At the same time, new technologies are enabling higher recovery volumes for shale producers in the oil window. As ExxonMobil's CEO recently explained, near-term technological improvements that allow operators to fracture along wells more precisely and keep fractured cracks open longer could double crude output from existing wells for shale producers.[4] Such improvements in operational efficiency have allowed producers to maintain a consistent return on capital employed (ROCE) even at prices as low as half of the current price for crude oil. (*See* Figure 3).

[4] BNN Bloomberg. (2023, June 1). *Exxon Bets New Ways to Frack Can Double Oil Pumped From Shale Wells*. https://www.bnnbloomberg.ca/exxon-bets-new-ways-to-frack-can-double-oil-pumped-from-shale-wells-1.1927597

Figure 3. Actual Crude Oil Spot Price Versus Price Required for 10% Return on Capital



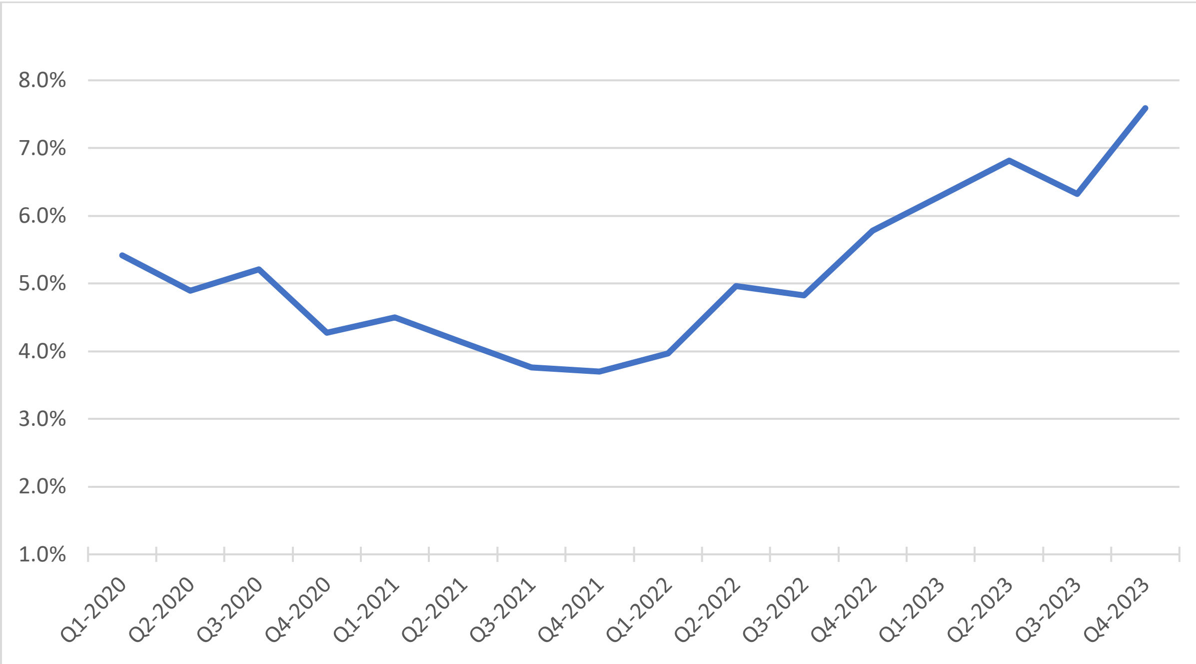
Data sources: EOG Resources (2024); EIA (2024).[5]

The improving economics for oil in the Ohio Utica have led to a recent increase in its share of overall production, as seen in Figure 4. Continued oil production growth in the region could lead to additional investments into refining capacity. Refineries in and around Ohio have been operating at capacity utilizations greater than 90%.[6] Ohio's oil refineries have an average refining capacity of around 150,000 barrels per day, or 55 million barrels annually.[7] Regional refineries therefore could require significantly more annual processing capacity, given recent development trends.

Ohio Utica oil production in 2022 was 19.6 million barrels, 19.9% greater than in 2021. In 2023, production of 27.8 million barrels was 41.3% greater than in 2022. Should this rate of growth in oil production continue, the Ohio Utica will produce somewhere between 33.3 and 39.3 million barrels of oil in 2024, potentially requiring over 10 million barrels of additional annual refining capacity compared to 2023. Recent investment announcements by operators in the region of accelerated development of the Utica oil play indicate that this growth trend will likely continue.[8]

[5] See EOG Resources. (2024, February 23). *4Q 2023: Earnings Presentation*. https://filecache.investorroom.com/mr5ir_eogresources2/307/EOG_0224v2.pdf. *See also* EIA. (2024). *Cushing, OK WTI Spot Price FOB*. https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RWTC&f=M
[6] *See* EIA. (2024). *Refinery Utilization and Capacity*. https://www.eia.gov/dnav/pet/pet_pnp_unc_dcu_nus_m.htm.
[7] *See* EIA. (2023). *Capacity of Operable Petroleum Refineries by State.* https://www.eia.gov/petroleum/refinerycapacity/table3.pdf
[8] *See* Encino Acquisition Partners. (2024, April 2024). *Encino Acquisition Partners, LLC Announces $300 Million Equity Commitment from CPP Investments*. https://www.prnewswire.com/news-releases/encino-acquisition-partners-llc-announces-300-million-equity-commitment-from-cpp-investments-302123176.html

Figure 4. Oil's Share of Total Utica Production in Ohio



Data Source: ODNR (2024)

Ohio Department of Natural Resources Division of Oil and Gas (ODNR) data indicate that 75 new wells were drilled during the first and second quarters of 2023. ODNR production data also indicate that the total volume of gas-equivalent shale production in the first half of 2023 was 1.3% greater than overall production in the second half of 2022. The increase in production was, however, due entirely to the new interest in the Utica oil window. While gas production was essentially unchanged in the first half of 2023 compared to the previous six-month period (difference of less than 0.1%), oil production increased more than 25% over this time frame. The Study Team will continue to track developments in oil production for the Utica in Ohio.

For the first half of 2023, Jefferson County had the highest number of new wells with 15, followed by Belmont and Columbiana Counties with 14 new wells each, Carroll County with 9, and Noble County with 7. Guernsey and Harrison Counties had 6 wells each, while Monroe County had 4 new wells. No other new wells were drilled during the first six months of 2023.

Ascent and EAP Ohio were the top producers for Q1 and Q2 of 2023, having produced 466 and 247 billion cubic feet equivalent (Bcfe), respectively. Gulfport was third in production at 168 Bcfe. SWN Production (Southwestern) and Rice Drilling produced 89 Bcfe and 52 Bcfe, respectively. Antero had the sixth highest production during the Study period at 38 Bcfe. These six companies represented a little over 91% of total production in Ohio for the first half of 2023.

The first half of 2023 saw midstream investment of $172.3 million, a more than threefold increase in spending for this segment compared to the previous 6-month period. The majority of midstream investment during the Study period was for gathering system buildout, with $110.3

million spent on gathering lines and nearly $31 million spent on compression and dehydration. An additional $31.5 million was spent on NGL pipeline. Slightly more than this total amount of midstream investment also occurred in the second half of 2023.

There was little downstream investment in the first half of 2023, with $1.5 million in liquified petroleum gas (LPG) fueling stations opening throughout the state. However, this is not a trend, as construction began in earnest on the $1.2 billion natural gas-fired Trumbull Energy Center in Lordstown during the second half of 2023. This investment will be captured in the next Shale Investment Dashboard. Additionally, progress continues on a number of Department of Energy-funded projects that leverage the region's abundant supply of natural gas for economical hydrogen production and usage for industrial, transportation, and power sector applications. Such projects include up to $500 million for hydrogen-based iron and steel production and a portion of more than $925 million (excluding industry match) across multiple end uses as part the Appalachian Regional Clean Hydrogen Hub (ARCH2) led by Battelle.[9] These and other investments will be tracked by the Study Team for future Dashboard reports.

1. INTRODUCTION

This is the fifteenth CSU study reporting investment resulting from oil and gas development in Ohio related to the Utica and Point Pleasant formations (hereinafter, the "Utica").[10] This analysis looks at investments made in Ohio between January 1 and June 30, 2023, separately considering the upstream, midstream, and downstream portions of the industry. For the upstream part, the Study Team estimated spending primarily based upon the likely costs of drilling new and operating existing wells, together with royalties and lease bonuses.

For midstream estimates, the Study Team looked at new infrastructure built during the relevant time period downstream of production, from gathering to the point of hydrocarbon distribution. This included pipelines, processing, natural gas liquid storage, and intermodal transloading facilities.

For the downstream analysis, the Study Team considered those industries that directly consume large amounts of oil, natural gas or natural gas liquids. Since hydrocarbon consumption may or may not be related to shale development, the examination of downstream investment has been limited to those projects that have been deemed by the Study Team to be dependent on, or directly the result of, the large amount of oil and gas being developed in the region as a result of the Marcellus and Utica shale formations.

[9] *See* Cleveland Cliffs. (2024, March 25). *Cleveland-Cliffs Selected to Receive $575 Million in US DoE Investments for Two Projects to Accelerate Industrial Decarbonization Technologies*. https://www.clevelandcliffs.com/news /news-releases/detail/629/cleveland-cliffs-selected-to-receive-575-million-in-us. *See also* DOE Office of Clean Energy Demonstrations. (2024). *Regional Clean Hydrogen Hubs Selections for Award Negotiations*. https://www.energy.gov/oced/regional-clean-hydrogen-hubs-selections-award-negotiations

[10] This and other Investment Dashboard reports include drilling into the Marcellus and other shale units, but these comprise a very small portion of shale development in Ohio to date. This will be revisited as necessary in future iterations of the Investment Dashboard reports.

This fifteenth Study includes as Appendix A the cumulative investment made in Ohio resulting from shale development, based upon all previous reports that tracked total investment from early 2011 through June 2023.[11] The methodology for determining the investments is set forth in Appendix B, and has been updated since the last report. Subsequent reports will include incremental spending on a six-month basis.

2. SHALE INVESTMENT UPDATES

A. UPSTREAM DEVELOPMENT

1. Overview.

A total of 75 new wells were listed by the Ohio Department of Natural Resources as "drilled," "drilling," or "producing" during the period of January 1 to June 30, 2023.[12] This represents a 13.6% increase in new well development compared to the second half of 2022. The total number of production wells in the Utica was 3,105 on June 30, 2023, a 2.7% increase from the end of December 2022. Total shale-related oil and gas production in billion cubic feet equivalent (Bcfe) for this period was 1,164 Bcfe, led by Jefferson County with 295 Bcfe. Belmont County was second with 294 Bcfe, followed by Monroe and Harrison Counties with 175 and 173 Bcfe, respectively.[13]

The Ohio Department of Natural Resources (ODNR), Division of Oil and Gas Resources Management, issues weekly reports on well status and quarterly reports on production. The ODNR production reports for the first and second quarters of 2023 provide the foundation for the upstream analyses presented in this Study.

The Utica is currently identified by the ODNR as producing in eighteen eastern Ohio counties with the vast majority (nearly 99%) of producing wells located in eight counties, stretching from Columbiana in the north, to Monroe and Noble at the southern end of the play. Total production in quarters 1 and 2 for 2023 is set forth by county and operator in Figures 5 and 6 below. (Figure 4 includes a comparison of total production by county for the first half of 2023 and the preceding

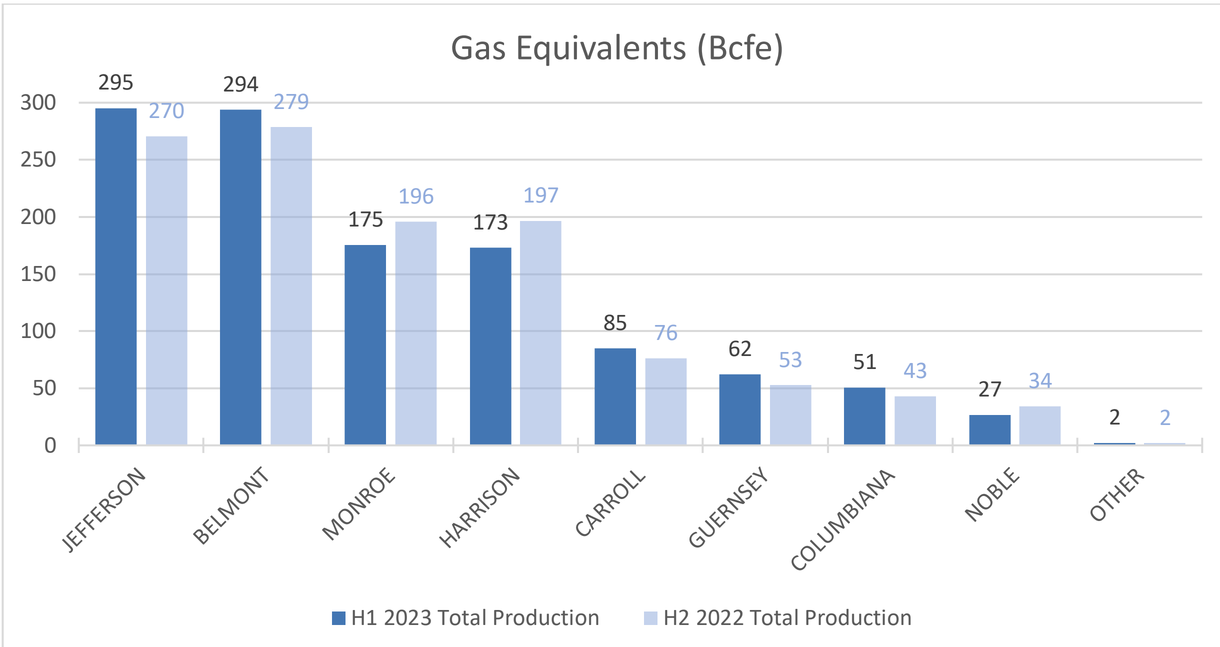
[11] *See fn 1, supra*.

[12] The number of new wells was determined using ODNR's report of cumulative permitting and drilling activity for the beginning and end of the 6-month period (*see* https://ohiodnr.gov/business-and-industry/energy-resources/oil-and-gas-wells/horizontal-wells). Wells are assigned an American Petroleum Institute API number, which is included in the ODNR reports. Wells were considered new if they had a status of drilled, drilling, or producing at the end of the 6-month period but did not have any one of these status designations at the beginning of it.

[13] Production is reported to the ODNR at the wellhead as gas measured in thousands of cubic feet (Mcf) and as oil measured in barrels (bbl). The Utica also produces significant volumes of natural gas liquids (NGLs) such as ethane, propane, butane and natural gasoline. These NGLs are separated from the natural gas stream at midstream cryogenic and fractionation plants and not included in the ODNR production reports. For the purposes of this Study, oil and gas production is combined as gas equivalents (Mcfe) based on the energy content of oil and gas, measured as British thermal units (Btu). Gas equivalents were calculated using the following formula: Gas Equivalents (Mcfe) = Oil (bbl) x 5.659 Mcf/bbl + Gas (Mcf).

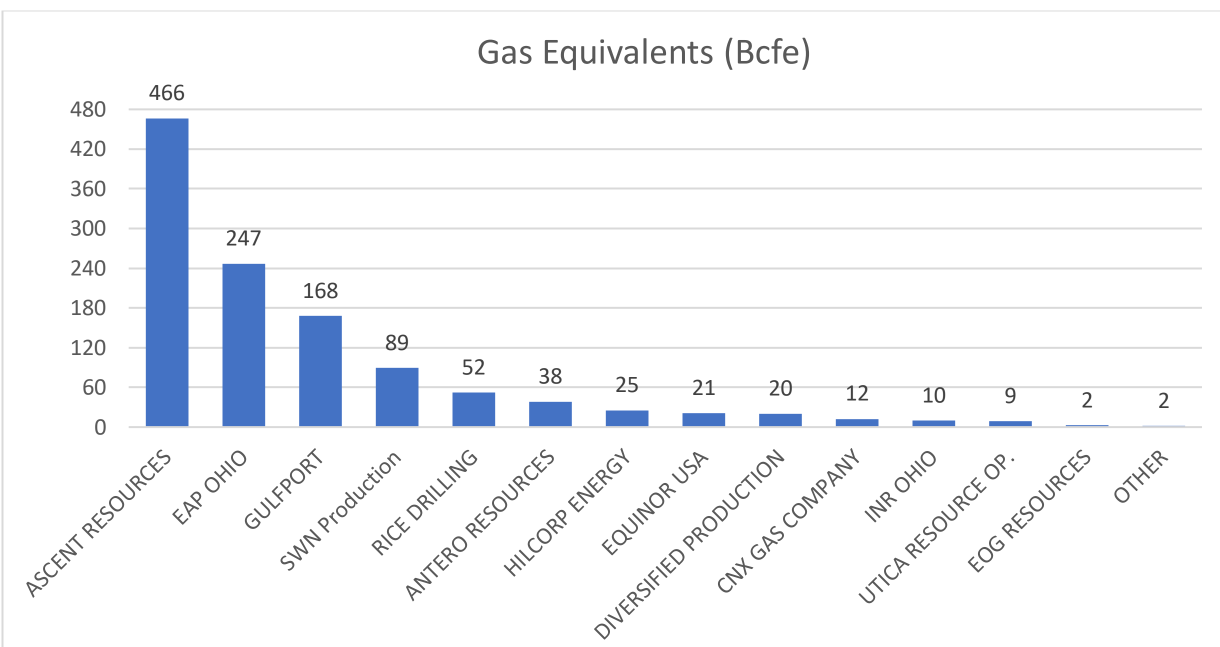
6-month period.) Total cumulative production in billions of cubic feet equivalent (Bcfe) by county and by operator through June 2023 can be found in Appendix A as Figures 9 and 10.

Figure 5: Production by County for First Half 2023 and Second Half 2022



Data Source: ODNR (2024).

Figure 6: Production by Operator for Q1 and Q2 of 2023



2. Production Analysis.

Production can be summarized using tables that show gas equivalent production measured in billions of cubic feet equivalent as a function of time. This summary, for both production in the first and second quarters of 2023, and also for cumulative production since 2011, is set forth in Table 1. Table 2 sets forth production by county for the first half of 2023. Figure 7 sets forth the geographic distribution of production for the same period.

Table 1: Ohio's Shale Production by Reporting Period

Year	Quarter	Production Wells	Gas (Mcfe)	Oil (bbl)	Gas Equivalents (Mcfe)	Gas Production (% Change from Previous Quarter)
2023	2	3,135	535,540,115	6,921,158	574,706,949	-2.4
2023	1	3,074	551,830,848	6,549,638	588,895,250	2.8
2022	4	3,033	539,681,875	5,855,323	572,817,148	-0.6
2022	3	3,014	548,326,581	4,908,109	576,101,570	0.8
2022	2	2,921	543,019,311	5,018,523	571,419,133	1.3
2022	1	2,850	541,815,020	3,957,294	564,209,347	-5.8
2021	4	2,817	576,496,677	3,912,593	598,638,041	5.2
2021	3	2,764	547,540,443	3,781,319	568,938,927	-0.6
2021	2	2,805	549,211,398	4,154,041	572,332,375	-0.2
2021	1	2,752	548,129,151	4,543,462	573,417,606	-6.4
2020	4	2722	586,878,969	4,625,639	612,624,813	-1.3
2020	3	2688	588,630,465	5,713,477	620,431,107	3.6
2020	2	2643	569,396,136	5,182,481	598,723,796	-2.6
2020	1	2573	581,634,083	5,887,032	614,948,797	-14.1
2019	4	2524	677,685,505	6,818,682	716,272,426	0.2
2019	3	2470	673,962,146	7,200,304	714,708,666	10
2019	2	2365	614,218,362	5,813,755	647,118,402	1.4
2019	1	2277	609,452,391	5,073,536	638,163,531	-8.4
2018	4	2201	663,534,323	5,810,484	696,415,852	9.3
2018	3	2198	605,716,125	5,545,536	637,098,313	9.9
2018	2	2002	554,306,916	4,488,104	579,705,097	4.7
2018	1	1906	531,291,017	3,942,251	553,600,215	5.1
2017	4	1866	503,066,907	4,193,562	526,784,387	8.7
2017	3	1769	460,844,826	4,207,674	484,656,053	18.1
2017	2	1646	387,725,175	4,019,281	410,512,053	4.7
2017	1	1530	369,913,713	3,877,717	391,904,993	2.5
2016	ANNUAL	1492	1,386,584,598	17,847,818	1,487,651,097	--
2015	ANNUAL	1248	923,908,838	20,698,159	1,041,039,721	--
2014	ANNUAL	810	449,966,930	10,893,625	511,613,948	--
2013	ANNUAL	371	99,050,302	3,635,419	119,623,141	--
2012	ANNUAL	82	12,831,292	635,874	16,429,703	--
2011	ANNUAL	9	2,561,524	46,326	2,823,683	--
Total			**15,159,372,543**	**161,523,968**	**16,071,805,223**	--

Source: ODNR (2023).

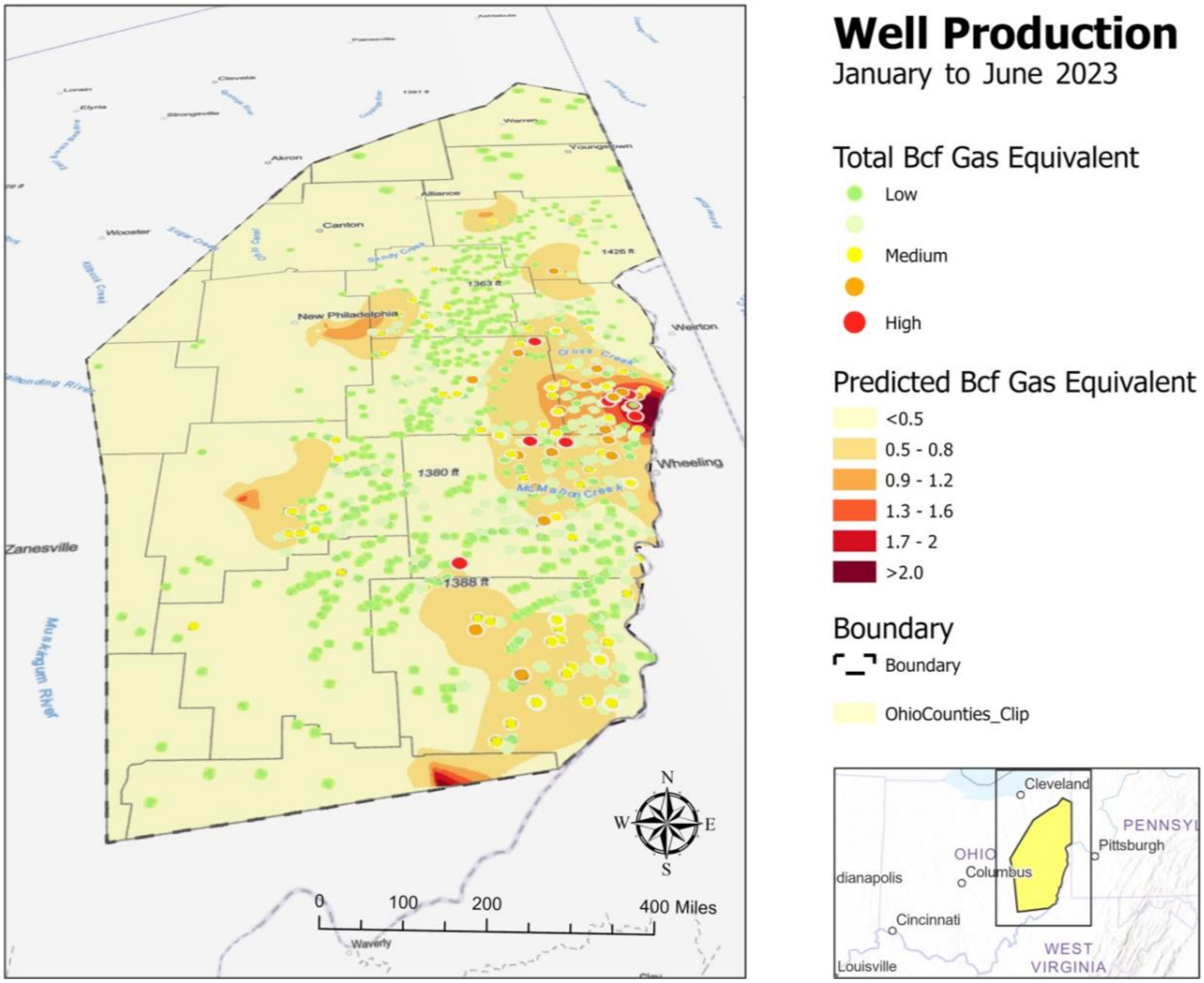
Table 2: Production by County for January – June 2023

County	Gas (Mcfe)	Oil (bbl)	Gas Equivalents (Mcfe)	Production Wells[14]
BELMONT	293,298,730	91,436	293,816,166	647
CARROLL	57,911,622	4,735,355	84,708,996	533
COLUMBIANA	48,530,896	376,059	50,659,014	129
COSHOCTON	12,635	0	12,635	1
GUERNSEY	34,941,821	4,831,145	62,281,271	282
HARRISON	156,211,176	2,943,722	172,869,699	490
JEFFERSON	295,169,917	59	295,170,251	356
MAHONING	407,060	2,484	421,117	11
MONROE	174,092,827	230,373	175,396,509	448
MORGAN	35,134	2,009	46,503	2
MUSKINGUM	153,561	2,568	168,093	2
NOBLE	25,346,090	237,771	26,691,636	177
PORTAGE	246,449	3,479	266,137	3
STARK	51,185	3,900	73,255	2
TRUMBULL	156,979	368	159,062	6
TUSCARAWAS	124,865	5,523	156,120	5
WASHINGTON	657,553	4,545	683,273	11
WAYNE	22,463	0	22,463	1
Total	**1,087,370,963**	**13,470,796**	**1,163,602,199**	**3,105**

Source: ODNR (2024).

[14] Represents the average number of production wells for the first and second quarters of 2023.

Figure 7: Distribution of Gas Equivalent Production for January – June 2023



Note: *Predicted Bcf Gas Equivalent* refers to the estimated average production for any random well located within one of the six color-coded spatial zones in the underlying contour plot.

Of the 3,259 total wells identified from the ODNR records for cumulative drilling activity as of June 2023, 126 were in the process of drilling, 73 wells had been drilled and were awaiting markets, and 3,060 were in the production phase.[15] (*See* Table 3, Ohio Utica Well Status.) Belmont County continued to lead in total wells. (*See* Table 4.)

[15] The discrepancy between the number of "Producing" wells in Table 3 and "Production" wells in Table 2 is due to how wells are reported in the ODNR's *Shale Well Drilling & Permitting* and *Well Production* spreadsheets. For a particular point in time, a given well may be classified as non-producing in the spreadsheet for cumulative activity yet have a record of production in the well production spreadsheet. Further, the Study Team has not sought to identify wells that may be listed as producing, but in fact are not.

Table 3: Ohio Utica Well Status as of June 2023

Well Status	No. of Wells
Drilled	73
Drilling	126
Producing	3,060
Total	**3,259**

Source: ODNR (2023)

Table 4: Well Status by County (June 2023)

County	Drilled	Drilling	Producing	Total
BELMONT	15	29	645	689
CARROLL	1	8	525	534
HARRISON	5	23	492	520
MONROE	17	14	414	445
JEFFERSON	1	21	356	378
GUERNSEY	2	14	271	287
NOBLE	1	6	181	188
COLUMBIANA	10	10	129	149
MAHONING	1	0	12	13
TRUMBULL	3	1	7	11
WASHINGTON	0	0	11	11
PORTAGE	7	0	2	9
TUSCARAWAS	2	0	7	9
STARK	4	0	2	6
COSHOCTON	1	0	1	2
MORGAN	0	0	2	2
MUSKINGUM	0	0	2	2
ASHLAND	1	0	0	1
KNOX	1	0	0	1
MEDINA	1	0	0	1
WAYNE	0	0	1	1
Total	**73**	**126**	**3,060**	**3,259**

B. UPSTREAM INVESTMENT ESTIMATES

Upstream investments have been broken down into four areas: investments into drilling, including road construction associated with well development; lease operating (post-production) expenses; new lease and lease renewal bonuses; and royalties on hydrocarbon production. The methodology used for each calculation is set forth in Appendix B. Average drilling costs were updated for this study, based upon reports from publicly traded operating companies. A recent review of ODNR drilling surveys indicated that the average well depth and horizontal length between northern and southern counties remains negligible.[16] Based on an average lateral length of 14,300 ft. for the eight most active shale-producing counties in Ohio over the last two years, and average drilling and completion costs of $800 per lateral foot for operators in the Utica during 2023, we assumed an average drilling cost of $11.4 million per well.[17]

This section covers upstream investments between January and June 2023. Cumulative upstream investments to date in Ohio, including 2011 through the first half of 2023, are set forth in Table 17 of Appendix A.

1. Investments into Drilling.

The following tables set forth estimated investments for the Study period made into drilling shale wells in Ohio. Jefferson County was the leader in new upstream investment, with 15 new wells and an investment of around $174.2 million between January and June 2023. Belmont and Columbiana Counties were tied for second, each with 14 new wells, and approximately $162.5 million invested. Carroll County was third with upstream investment of $104.5 million for 9 new wells (*See* Table 5.) Road-related investments for this version of the Shale Investment Dashboard reflect average road costs per well determined from the Ohio Oil and Gas Association's (OOGA) 2017 report *Ohio's Oil & Gas Industry Road Improvement Payments*, in conjunction with OOGA's *2022 Community Impact/Sustainability Report*.[18] Based on information from these reports, and after adjusting for recent inflation, road costs related to drilling were assumed to be $170,200 per well.[19]

[16] Previous shale reports differentiated between northern and southern counties with respect to drilling costs based on the greater vertical depths and horizontal lengths of wells developed in southern counties, on average.
[17] *See* Upstream Methodology in Appendix B.
[18] OOGA's 2017 report indicated that oil and gas companies in Ohio had spent $300 million on roads from 2011 through 2017. OOGA's 2022 report indicated that cumulative spending by the industry on roads had reached $400 million by the end of 2021. This suggests that $100 million was spent on roads from 2018 through 2021, a period during which the Study Team tracked 846 new wells, indicating an average investment of $118,200 per well.
[19] Producers have experienced recent increases in drilling and completion costs due to inflation. Road construction costs have risen 20% annually on average since 2021 according to the Federal Highway Administration's National Highway Construction Cost Index (*see* https://www.fhwa.dot.gov/policy/otps/nhcci/). Likewise, producers in the Appalachian Basin including Antero and EQT have similarly reported spending on road improvements in recent ESG reports that, in conjunction with the number of new wells these companies have drilled annually since 2021 according to their annual 10-K filings, have resulted in a cost per well for road upgrades that has increased by no less than 20% annually since 2021. The average per well investment of $118,200 for road improvements was adjusted assuming a price level increase for road construction of 20% annually over the last two years. *See*

Ascent was the leading operator-investor during the six-month period, with 34 new wells and an estimated $394.7 million invested. EAP Ohio recorded the second highest investment, with 13 new wells and an estimated $150.9 million invested. Hilcorp Energy drilled 7 new wells for an estimated investment of $81.3 million, followed by Antero and Gulfport, each with $69.7 million invested for 6 new wells. (*See* Table 6.)

Table 5: Estimated Upstream Shale Investment by County, January – June 2023

County	No. of New Wells	Drilling ($)	Roads ($)	Total Amount ($)
BELMONT	14	$160,160,000	$2,382,800	$162,542,800
CARROLL	9	$102,960,000	$1,531,800	$104,491,800
COLUMBIANA	14	$160,160,000	$2,382,800	$162,542,800
GUERNSEY	6	$68,640,000	$1,021,200	$69,661,200
HARRISON	6	$68,640,000	$1,021,200	$69,661,200
JEFFERSON	15	$171,600,000	$2,553,000	$174,153,000
MONROE	4	$45,760,000	$680,800	$46,440,800
NOBLE	7	$80,080,000	$1,191,400	$81,271,400
Total	**75**	**$858,000,000**	**$12,765,000**	**$870,765,000**

Source: The Authors (2024)

Table 6: Estimated Upstream Shale Investment in Ohio by Company, January – June 2023

Operator	No. of New Wells	Drilling ($)	Roads ($)	Total Amount ($)
ANTERO RESOURCES	6	$68,640,000	$1,021,200	$69,661,200
ASCENT RESOURCES	34	$388,960,000	$5,786,800	$394,746,800
EAP OHIO	13	$148,720,000	$2,212,600	$150,932,600
ECLIPSE RESOURCES	1	$11,440,000	$170,200	$11,610,200
EOG RESOURCES	2	$22,880,000	$340,400	$23,220,400
GULFPORT	6	$68,640,000	$1,021,200	$69,661,200
HILCORP ENERGY	7	$80,080,000	$1,191,400	$81,271,400
INR OHIO	2	$22,880,000	$340,400	$23,220,400
SWN Production	4	$45,760,000	$680,800	$46,440,800
Total	**75**	**$858,000,000**	**$12,765,000**	**$870,765,000**

Source: The Authors (2024)

https://www.anteroresources.com/esg. *See also* https://esg.eqt.com/social/economic-and-societal-impacts/#giving-back-to-our-communities

2. Lease Operating Expenses.

Post-production investments have been estimated on a half-year basis, assuming an average cost of $0.167/Mcf-equivalent.[20] This estimate is based upon recent operator reports.[21] These investments are set forth below. Jefferson County and Belmont County led the lease operating expense investment, with an estimated $49.3 million and $49.1 million invested, respectively.

Table 7: Estimated Lease Operating Expenses for January – June 2023 by County

County	Gas Equivalents (Mcfe)	Lease Operating Expense for Period
JEFFERSON	295,170,251	$49,293,432
BELMONT	293,816,166	$49,067,300
MONROE	175,396,509	$29,291,217
HARRISON	172,869,699	$28,869,240
CARROLL	84,708,996	$14,146,402
GUERNSEY	62,281,271	$10,400,972
COLUMBIANA	50,659,014	$8,460,055
NOBLE	26,691,636	$4,457,503
OTHER	2,008,657	$335,446
TOTAL	**1,163,602,199**	**$194,321,567**

Table 8: Estimated Lease Operating Expenses for January – June 2023 by Operator

Operator	Gas Equivalents (Mcfe)	Lease Operating Expense for Period
ASCENT RESOURCES	466,424,166	$77,892,836
EAP OHIO	246,974,117	$41,244,678
GULFPORT APPALACHIA	167,981,036	$28,052,833
SWN Production	89,328,909	$14,917,928
RICE DRILLING	51,978,954	$8,680,485
ANTERO RESOURCES	38,458,438	$6,422,559
HILCORP ENERGY	25,327,510	$4,229,694
EQUINOR USA	21,082,998	$3,520,861
DIVERSIFIED PRODUCTION	20,484,205	$3,420,862
CNX GAS COMPANY	12,477,925	$2,083,813
INR OHIO	9,748,633	$1,628,022
UTICA RESOURCE OPERATING	9,296,119	$1,552,452
EOG RESOURCES	2,479,544	$414,084
OTHER	1,559,644	$260,461
TOTAL	**1,163,602,199**	**$194,321,567**

[20] Previous reports relied on a per-well rule-of-thumb to calculate lease operating expenses, which attributed an equal amount to both low- and high-producing wells. A production-based rule of thumb more accurately captures the expenses that companies are likely to incur while operating wells.

[21] The per-Mcfe rule-of-thumb for lease operating expenses is based on average production costs for Ascent's and Gulfport's Utica operations in the first half of 2023 as reported in quarterly financial statements for both companies. *See* Appendix B.

3. Royalties.

Royalty investments have been estimated on a per quarter basis, assuming the formulas set forth in Appendix B. Total estimated royalties spent on Ohio properties between January and June 2023 were $763.8 million, or about half the amount dispersed in the second half of 2022 as oil and gas traded at near historic lows. The breakdown by quarter for oil, residue gas (gas left after extracting liquids), and natural gas liquids is set forth in Tables 9, 10, and 11 below. The average price for natural gas was $1.91/MMBtu during the first half of 2023, down from $5.78 in the second half of 2022.[22] Regional oil prices decreased from an average of $66.17/bbl during the first quarter of 2023 to $63.76/bbl for the second quarter.[23] For comparison, regional oil prices averaged $81.87 and $72.53 per barrel in the third and fourth quarters of 2022, respectively.

Table 9: Total Royalties from Oil, January – June 2023 (in millions)

Year	Quarter	Oil Price $/bbl	Oil Royalty (20%) $/bbl	Royalty ($mm)
2023	2	$63.76	$12.75	$88.26
2023	1	$66.17	$13.23	$86.67
			Subtotal	**$174.93**

Table 10: Total Royalties from Residue Gas, January – June 2023 (in millions)

Year	Quarter	Residue Gas Price $/Mcf	Residue Gas Royalty (20%) $/Mcf	Royalty ($mm)
2023	2	1.72	$0.34	$162.23
2023	1	2.47	$0.49	$240.11
			Subtotal	**$402.34**

Table 11: Total Royalties from Natural Gas Liquids, January – June 2023 (in millions)

Year	Quarter	NGL Price $/bbl	NGL Royalty (20%) $/bbl	Royalty ($mm)
2023	2	19.13	3.83	$90.14
2023	1	19.85	3.97	$96.40
			Subtotal	**$186.54**

[22] Reflects average natural gas prices over the respective periods across the Columbia Gas and Eastern Gas South (formerly Dominion South) trading hubs as derived from Intercontinental Exchange (ICE) trade data published in regular weekly market reports by Snyder Brothers Gas Marketing. *See* https://www.snyderbrothersinc.com.
[23] Reflects average prices reported by Ergon for Marcellus-Utica light crude (https://ergon.com). *See* Appendix B.

4. Lease Renewals and New Leases.

New leases and lease renewal investments have been estimated for the Utica region based upon the drilling activity of the top six drilling companies in the region. These six companies have together drilled over 88% of the Utica wells to date, and it is assumed that they likewise control over 88% of the leases. The estimated investments into new leases and lease renewals are set forth below in Table 12.

There are several potential sources of error in these estimates. Because operators do not report lease bonus information, the Study Team was required to estimate investments into lease bonuses based upon some industry rules of thumb, together with information found in public leases. One important rule of thumb we deployed in estimating lease bonus investment is that "primary" lease terms average about 5 years. The primary term is that period of time during which the operator may conduct drilling operations but hold the lease without producing. Once a lease is drilled and production begins, the lease moves into its "secondary term," and may be thereafter "held by production" (HBP) for the life of that production. Using this rule of thumb, we determined that each operator will, on average, every year replace about 20% of its undeveloped acreage that is not HBP.

However, it is possible to hold undeveloped acreage without producing it. This can be done through the process of unitization. An operator may, for instance, have a 750-acre unit that is designed to drain a reservoir by 3 wells draining 250 acres each. The operator may drill the first well and begin to pay royalties therefrom to all the unit leases, thereby moving all the unit leases into HBP status, even though only one third of the reservoir is actually producing. Under this scenario, 500 acres would be classified as "undeveloped acreage," while 250 acres would be "developed acreage."

Most operators report undeveloped acreage.[24] However, they generally do not distinguish what portions of their undeveloped acreage are HBP or under primary term. Some do, however, report what percentage of their overall acreage is HBP, and this number can be used to estimate the likely acreage of leases that required bonuses. Based on the most recent annual financial reports for Antero, Ascent, and Gulfport, the Study Team found that on average 14% of a Utica operator's net Utica acreage was not classified as "Held-By-Production." Accordingly, for purposes of this Study, and using the 5-year primary term assumption, we assumed that operators, on average, paid lease bonuses on 20% of such non-HBP acreage for the year (i.e. ~3% of the total net acreage), and 10% over the half-year Study period.

Another important assumption is the lease bonus rate. For this Study, we have assumed bonuses to average $5000/acre lease for renewals and new leases. From 2013-2019, this was a pretty

[24] *Undeveloped acreage* is defined by operators as that acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and natural gas regardless of whether the acreage contains proved reserves. Accordingly, undeveloped acreage can have a wide range of meaning, ranging from highly speculative to proven. Operators use a different, more rigorous classification system to account for proven or potential reserves.

conservative number in the Utica, and therefore likely to still be conservative for renewals of older leases. There is evidence that in 2020 new lease bonus rates were depressed due to sustained low natural gas prices. More recent publicly reported information on lease bonuses suggests, however, that $5000/acre continues to be a reasonable estimate. In May 2022, for example, the Muskingum Watershed Conservancy District leased mineral rights for $5,500/acre for a 5-year primary term on acreage in Harrison County.[25] And in early 2024, ODNR awarded leasing rights for drilling under Ohio public lands that included bonuses of $10,250/acre at Salt Fork State Park in Guernsey County and $3,500/acre at wildlife areas in Carroll and Columbiana Counties.[26]

One additional factor that may make the lease bonus estimate inaccurate is the use of only "net" non-HBP lease acreage data to avoid possible double counting of leases. Operating companies often collaborate on development with non-operators but report only their own portion of the lease. However, bonuses must be paid on the "gross" lease acreage. So long as the non-operators are among the top six operators (which is commonly the case), their own net acreage reports will capture all the acreage. But if they are not, the acreage will not be captured, and the bonuses estimated herein will be under reported.

[25] *See* Muskingum Watershed Conservancy District. (2022, May 20). *MWCD Negotiates Oil and Gas Lease with Encino Energy*. https://www.mwcd.org/news/2022/05/20/mwcd-negotiates-oil-and-gas-lease-with-encino-energy

[26] The leases awarded by ODNR's Oil and Gas Land Management Commission included 3-year primary terms and royalty rates of 20% at Salt Fork State Park and 18% at the wildlife areas in Carroll and Columbiana Counties. *See* Ohio Department of Natural Resources. (2024, February 27). *State Commission Awards Leasing Rights Following Competitive Bidding Process*. https://ohiodnr.gov/discover-and-learn/safety-conservation/about-ODNR/news/leasing-rights

Table 12: Total Estimated Investments into New Leases and Lease Renewals January – June 2023 (in millions)

Operator	Acreage not held for production[27]	Estimated Bonus Investment ($mm)
ANTERO RESOURCES[28]	13,731	$6.9
ASCENT RESOURCES[29]	43,809	$21.9
EAP OHIO[30]	15,361	$7.7
GULFPORT ENERGY[31]	27,082	$13.5
RICE DRILLING (EQT)[32]	15,798	$7.9
SOUTHWESTERN ENERGY (SWN)[33]	13,757	$6.9
Total	**129,539**	**$64.8**

C. Estimated Midstream Investments

Midstream investment includes natural gas processing and fractionation facilities, including rail and transloading facilities for storing and handling natural gas liquids. Midstream also includes transmission and gathering pipelines, storage facilities, compressor stations (including compressor engines), dehydration units, and generators installed as part of these stations.

Pipeline investments were estimated using mileage and size information from the Public Utilities Commission of Ohio, and cost information from the Interstate Natural Gas Association of America (INGAA). Similarly, compressor station investments were based on estimated cost per unit of power output for the region as obtained from the INGAA. A full description of the methodology can be found in Appendix B.

[27] Antero and Southwestern did not distinguish between Ohio, Pennsylvania, and West Virginia acreage for their Appalachia operations in their FY2023 10-K reports. EAP Ohio is privately held and does not release this sort of annual financial report. Gross developed acreage in Ohio for these companies was assumed to be equivalent to the total acreage for their horizontal drilling units in the state, data for which is available through the ODNR's Oil & Gas Well Viewer at https://gis.ohiodnr.gov/mapviewer/?config=oilgaswells. For operators who *do* file 10-K reports in which Appalachian acreage is differentiated by state (Ascent, Gulfport, and Rice Drilling), this estimate for gross developed acreage has been within ±10% of the actual amount. Total net acreage for Antero, Southwestern Energy, and EAP Ohio were estimated based on the average ratio of total-net-acres-to-gross-developed-acres in Ohio for Ascent, Gulfport, and Rice Drilling.

[28] Twelve percent of Antero's total net Ohio acreage was assumed to not be held by production as this was the percentage of the company's overall net Appalachian acreage not held by production in FY2023 based on its most recently filed 10-K.

[29] Twelve percent of Ascent's total net Ohio acreage was not held by production based on the company's FY2023 Consolidated Financial Statements.

[30] *See fn 26, supra.* Approximately 5% of EAP's acreage in Ohio is not held by production (*see* https://encinoenergy.com/utica-oil/).

[31] Fourteen percent of Gulfport's net Ohio acreage was not held by production based on its FY2023 10-K.

[32] Acreage not held by production was not identified in the FY2023 10-K for Rice Drilling or Southwestern Energy. This percentage was assumed to be 11%, which was the average for Antero, Ascent, EAP Ohio, and Gulfport.

[33] *Id.*

Additional investment information was collected from midstream company investor presentations, news reports, and other sources including Ohio EPA permits. Table 13 summarizes midstream investments identified by the Study Team for the first half of 2023. Some costs related to these projects may have occurred outside the six-month window for this study. However, because the investments cannot easily be separated and tracked while construction is ongoing, the investments are treated as though made entirely during the Study period if construction on the project was begun then.

Table 13: Midstream Investment, January – June 2023

Company	Additions to Infrastructure	Total Amount ($mm)
Antero Midstream	• 3.35 miles of 20" gathering pipeline	$17.9
Blue Racer Midstream	• 0.95 miles of 8.63" gathering pipeline	$2.2
Cardinal Gas Services (Williams)	• 1.72 miles of 8.63" gathering pipeline • 5.35 miles of 10.75" gathering pipeline • 4.52 miles of 12.75" gathering pipeline • 7.77 miles of 16" gathering pipeline	$68.0
EOG Resources	• 0.37 miles of 4.5" gathering pipeline • 3.63 miles of 12.75" gathering pipeline	$12.8
EQM Olympus Midstream (Equitrans)	• 5,350 hp of compression in Belmont County • 97 MMscfd of dehydration in Belmont County	$30.5
Eureka Midstream	• 2.90 miles of 12" gathering pipeline	$9.3
MPLX[34]	• 29.5 miles of NGL pipeline ≥ 4" in diameter	$31.6
	Total	**$172.3**

Source for Gathering Line Mileage and Diameter Data: PUCO Gathering Construction Reports (2024).

Midstream investments were up considerably during the first half of 2023, totaling around $172 million. By comparison, the Study Team tracked $78 million in midstream investment for all of 2022. Midstream operators in the Utica will continue to focus on expanding gathering and transportation capacity more so than processing in the near-term.[35]

[34] MPLX's FY2020-FY2022 10-Ks reported 119 miles of NGL pipeline with a diameter of between 4" and 12" for its Utica Operations. For FY2023, the company reported 178 miles of 4"-20" NGL pipeline for its Utica Operations (the annual financial reports do not itemize the mileage of pipeline by diameter, nor do they indicate in which quarter of FY2023 that the additions to capacity took place). The related midstream investment included herein reflects presumed spending for 59 miles of 4" diameter pipeline, with half of this investment captured in the current shale report and the rest to be included in the next shale report.

[35] *See* MPLX. (2024, January 30). *Fourth Quarter 2023 Earnings Conference Call*. https://www.mplx.com/content/documents/mplx/investor_center/2024/MPLX_4Q23_Slides.pdf. *See also* Williams. (2024, February 14). *Analyst Day 2024*. https://investor.williams.com/static-files/ec1d82fd-f97a-4233-87d2-2a7c03f96cb7

Such projects include DT Midstream's buildout of a new trunkline and gathering network in eastern Ohio, as well as the Ohio Valley Connector Expansion in Monroe County to increase takeaway capacity out of the region, construction for both having commenced in the second half of 2023.[36] These and other midstream projects to be included in the next shale report are listed below in Table 14. Cumulative midstream investments through the end of June 2023 are set forth in Table 18 in Appendix A.

Table 14: Ohio Midstream Projects for Second Half of 2023

Project	Description	Est. Investment ($mm)
DT Midstream	Buildout of new trunkline and gathering network	$100.0
MPLX[37]	29.5 miles of NGL pipeline ≥ 4" in diameter	$31.6
Ohio Valley Connector Expansion	Takeaway capacity out of Appalachia (Ohio portion)	$19.0
Additional gathering system buildout[38]	• 1.4 miles of gathering pipeline with 10" avg. diameter in Columbiana and Carroll Counties • 7,500 hp of compression in Belmont County	$43.3

D. Downstream Development

1. Combined Heat and Natural Gas Power Plants

Over the past thirteen reports, we have noted 10 new natural gas-powered power plants in Ohio that were in the planning, construction, or newly operational stages since 2015. The seven of these plants that are operational consumed 119.1 Bcf of natural gas for power generation during the first half of 2023, or about 11% of Ohio Utica gas production for this period. [39] These seven plants generated 19,026 gigawatt hours of electricity over the first six months of 2023, or about 27% of the electricity consumed in Ohio across all sectors during the study period.[40]

[36] *See* DT Midstream. (2023, December 7). *Wells Fargo Midstream and Utilities Symposium*. https://s28.q4cdn.com/581450200/files/doc_events/2023/Dec/07/dtm-company-presentation-december-2023-vf.pdf. *See also* FERC. (2023, August 8). *Notice of Commencement of Construction*. https://elibrary.ferc.gov/eLibrary/filedownload?fileid=3914FDA7-B6F1-C6AF-9321-89D682500000

[37] *See fn 34, supra*.

[38] Pipeline estimate reflects construction starts through the end of December 2023 as gathered from the PUCO's Gathering Construction Reports. Compression estimate reflects projects receiving Final Issuance of Permit-to-Install and Operate from Ohio EPA as of December 31, 2023. *See* Appendix B for methodology used to calculate total dollar amount.

[39] *See* Energy Information Administration. (2024, March 27). *Form EIA-923 Detailed Data with Previous Form Data (EIA-906/920)*. https://www.eia.gov/electricity/data/eia923. Form EIA-923 data include monthly and annual fuel consumption and electricity generation at the power plant level.

[40] *Id. See also* Energy Information Administration. (2024, March 7). *Form EIA-861M (Formerly EIA-826) Detailed Data*. https://www.eia.gov/electricity/data/eia861m/

While ground was broken in April 2023 for the $1.2 billion, 940 MW Trumbull Energy Center in Lordstown, most of the foundation work took place in the second half of 2023.[41] Also, the first natural gas turbines for the project were delivered in the second half of 2023.[42] This investment will therefore be accounted for in the next shale report.

Construction for Ohio State University's 106 MW CHP system continued into 2024. The district energy system is partially operational, providing chilled water and heating hot water to facilities in the Carmenton innovation district.[43] In the first quarter of 2024, the project budget was amended from $289.9 million (an amount captured in a previous Shale Dashboard) to $420.8 million.[44] The additional investment will be included in a future shale report.

The 10 current and projected natural gas-powered facilities across 8 locations, along with the CHP project at Ohio State, are set forth in Figure 8 below.

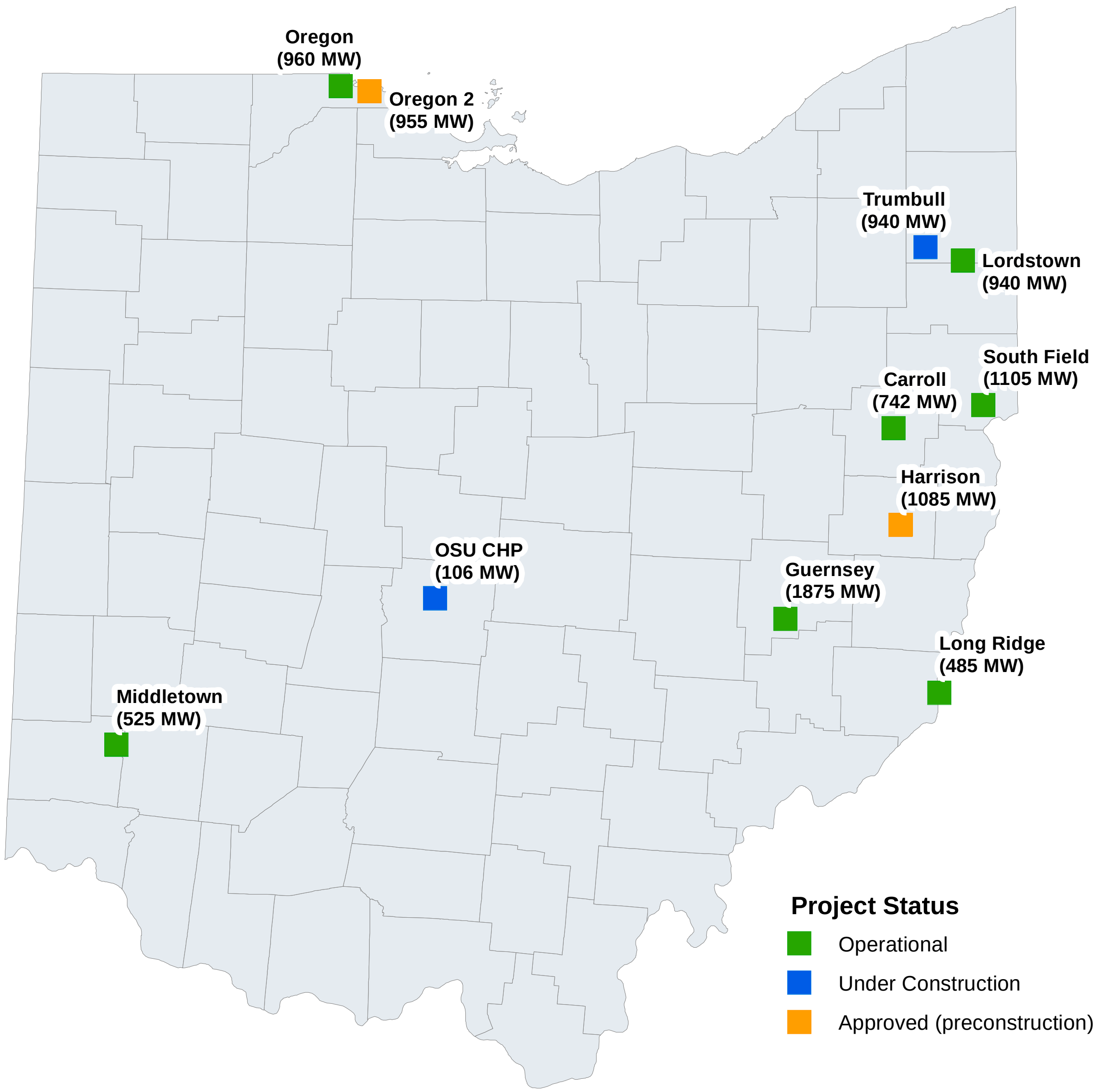
[41] *See* Tribune Chronicle. (2023, April 27). *Work underway at $1.2B Trumbull Energy Center as private ceremony takes place.* https://www.tribtoday.com/news/local-news/2023/04/work-underway-at-1-2b-trumbull-energy-center-as-private-ceremony-takes-place. *See also* Notice(s) of Upcoming Concrete Pour Occurring at http://trumbullenergycenter.com/

[42] Business Journal Daily. (2023, November 6). *First Turbine Delivered to Trumbull Energy Center Site*. https://businessjournaldaily.com/first-turbine-delivered-to-trumbull-energy-center-site/

[43] *See* Ohio State University Board of Trustees. (2024, February 22). Master Planning and Facilities Committee Meeting. https://trustees.osu.edu/sites/default/files/documents/2024/02/0_PUBLIC%20MATERIALS_MPF_February%202024_0.pdf

[44] *Id.*

Figure 8: Existing and Projected Natural Gas Power Plants



Source: Ohio Power Siting Board (2023)

2. Other Downstream Investment

a. Transportation

Five public liquefied petroleum gas (LPG) fueling stations opened across the state in the first half of 2023.[45] These stations are located at U-Haul self-storage and vehicle rental centers in Cuyahoga and Hamilton Counties, and at a Heritage Cooperative fuel station in Urbana, OH. Costs for equipment purchases and site work for LPG refueling stations such as those installed during the Study period are around $300,000 per station, for a total investment of $1.5 million across five stations.[46]

b. Hydrogen

As previously reported, the Battelle-led Appalachian Regional Clean Hydrogen Hub (ARCH2) consortium—composed of private, public, and non-profit sector participants from across parts of Ohio, West Virginia, Kentucky, and Pennsylvania—was selected by the Department of Energy (DOE) to receive up to $925 million to accelerate the commercial-scale deployment of clean hydrogen in the region.[47] The funding will catalyze at least the same amount in private investment—up to $6 billion by some estimates—under a 50 percent minimum cost matching requirement.[48] Access to low-cost natural gas and CO2 storage capacity will be key drivers in realizing low-cost clean hydrogen for end-users in the region.[49]

While final funding details are still being negotiated with DOE, Battelle released a summary of proposed project locations in Ohio, along with the private sector partners involved, during an October 2023 community briefing outlining regional clean hydrogen hub progress.[50] Proposed projects include an MPLX hydrogen storage facility in Southeast Ohio; a partnership between Plug Power and Amazon to operate hydrogen-powered material handling equipment and delivery trucks in Central and Northeast Ohio; and hydrogen production with CO2 capture by Enbridge Gas Ohio (formerly Dominion Energy Ohio) to supply regional transit fleets operating fuel cell electric vehicles.

[45] Alternative Fuels Data Center. (2024). Locate Stations [Station Data by State]. https://afdc.energy.gov/data_download.
[46] *See* U-Haul. (n.d.). *Propane AutoGas Trip Planner* [What is Propane AutoGas Fleet?]. https://www.uhaul.com/Propane/AutoGas
[47] DOE Office of Clean Energy Demonstrations. (2024). *Regional Clean Hydrogen Hubs Selections for Award Negotiations*. https://www.energy.gov/oced/regional-clean-hydrogen-hubs-selections-award-negotiations
[48] *See* Senate Committee on Energy & Natural Resources. (2023, October 13). *Manchin Announces West Virginia Selected as New Home of Appalachian Hydrogen Hub*. https://www.energy.senate.gov/2023/10/manchin-announces-west-virginia-selected-as-new-home-of-appalachian-hydrogen-hub
[49] The DOE's clean hydrogen production standard targets 4 kg of CO2-equivalent or less per kilogram of generated hydrogen (*see* https://www.hydrogen.energy.gov/library/policies-acts/clean-hydrogen-production-standard).
[50] DOE Office of Clean Energy Demonstrations. (2023, October 24). *Regional Clean Hydrogen Hubs: Appalachian Regional H2Hub Community Briefing*. https://www.energy.gov/sites/default/files/2023-10/H2Hubs_Appalachian_Community_Briefing.pdf

Under a separate DOE funding opportunity, Cleveland Cliffs was also recently awarded up to $500 million to replace the coal-burning blast furnace at its Middletown Works Facility with a unit that uses hydrogen.[51] This and other hydrogen-related projects falling within the scope of upstream, midstream, or downstream activities will be tracked for inclusion in future shale reports.

Cumulative downstream investments reported to date in Ohio, including 2011 through the first half of 2023, are set forth in Table 19 in Appendix A. An outline of the key products and processes for this sector within the shale gas value chain is set forth in Appendix B.

3. CONCLUSION

Total upstream shale investment in Ohio was down (-20.3%) for the first half of 2023 compared to the second half of 2022, even though new well drilling and total production both increased. This was due entirely to the decline in regional natural gas prices, which fell by more than two-thirds (-67.1%) during this time frame. Jefferson County led all counties in production, displacing Belmont County which previously led county-level production for all prior Shale Dashboards. Jefferson County's lead in production has coincided with its lead in new well development over the last few years.[52] Altogether, upstream shale investment totaled nearly $1.9 billion for the first half of 2023.

Midstream investments for the first half of 2023 increased markedly (+321%) from spending during the second half of 2022. Gathering system buildout accelerated during the Study period, with an estimated investment of $110.3 million for gathering lines, $28.1 for compression, and $2.4 million for dehydration. An additional $31.5 million was spent on NGL pipeline expansion. Comparable investments in midstream infrastructure continued into the second half of 2023.

The first half of 2023 saw a pause in downstream investment, with five LPG fueling stations representing a total investment of around $1.5 million being placed into service. DOE's recent awarding of over $1 billion to develop hydrogen-related applications that leverage the region's abundant natural gas resources will spur additional private investment into 2024 and beyond.

Altogether, shale-related investment in Ohio for the first half of 2023, including upstream, midstream, and downstream, was just under $2.1 Billion. Cumulative total shale related investment since 2012 is around $105.2 billion.

[51] Cleveland Cliffs. (2024, March 25). *Cleveland-Cliffs Selected to Receive $575 Million in US DoE Investments for Two Projects to Accelerate Industrial Decarbonization Technologies*. https://www.clevelandcliffs.com/news /news-releases/detail/629/cleveland-cliffs-selected-to-receive-575-million-in-us

[52] From the beginning of 2020 through the end of June 2023, the Study Team has tracked 143 new wells in Jefferson County. Harrison County was second with 98 new wells during this time, followed by Belmont County with 97.

About the Study Team

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About the Energy Policy Center
The Energy Policy Center is housed within the Maxine Goodman Levin School of Urban Affairs at Cleveland State University. The mission of the EPC is to help overcome social and institutional barriers to the implementation of solutions to energy challenges by providing an objective channel for the free exchange of ideas, the dissemination of knowledge, and the support of energy related research in the areas of public policy, economics, law, business and social science. For more information, go to http://urban.csuohio.edu/epc/.

4. APPENDICES

APPENDIX A. CUMULATIVE OHIO SHALE INVESTMENT

Figure 9: Total Utica Production in Bcfe (Gas Equivalence) by County through June 2023

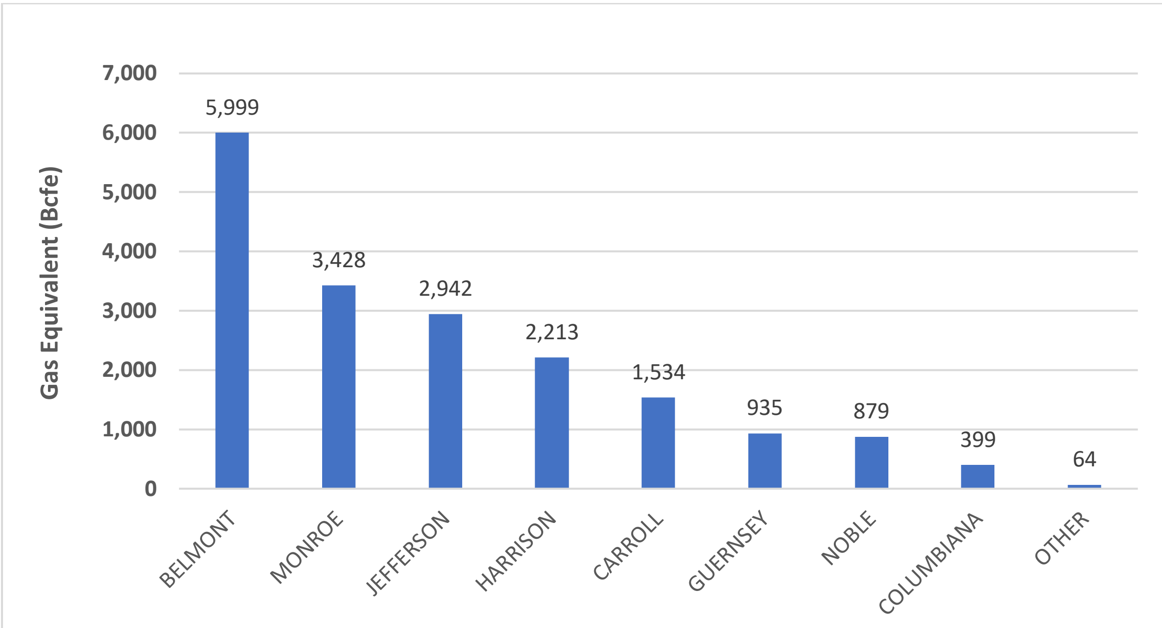


Figure 10: Total Utica Production in Bcfe by Operator through June 2023

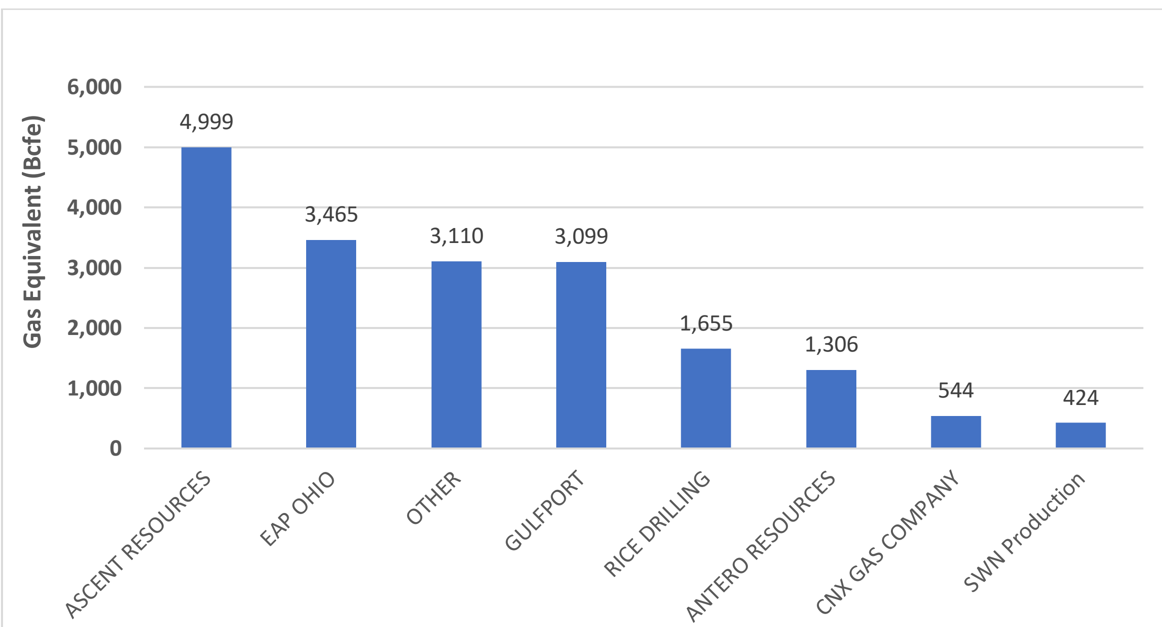
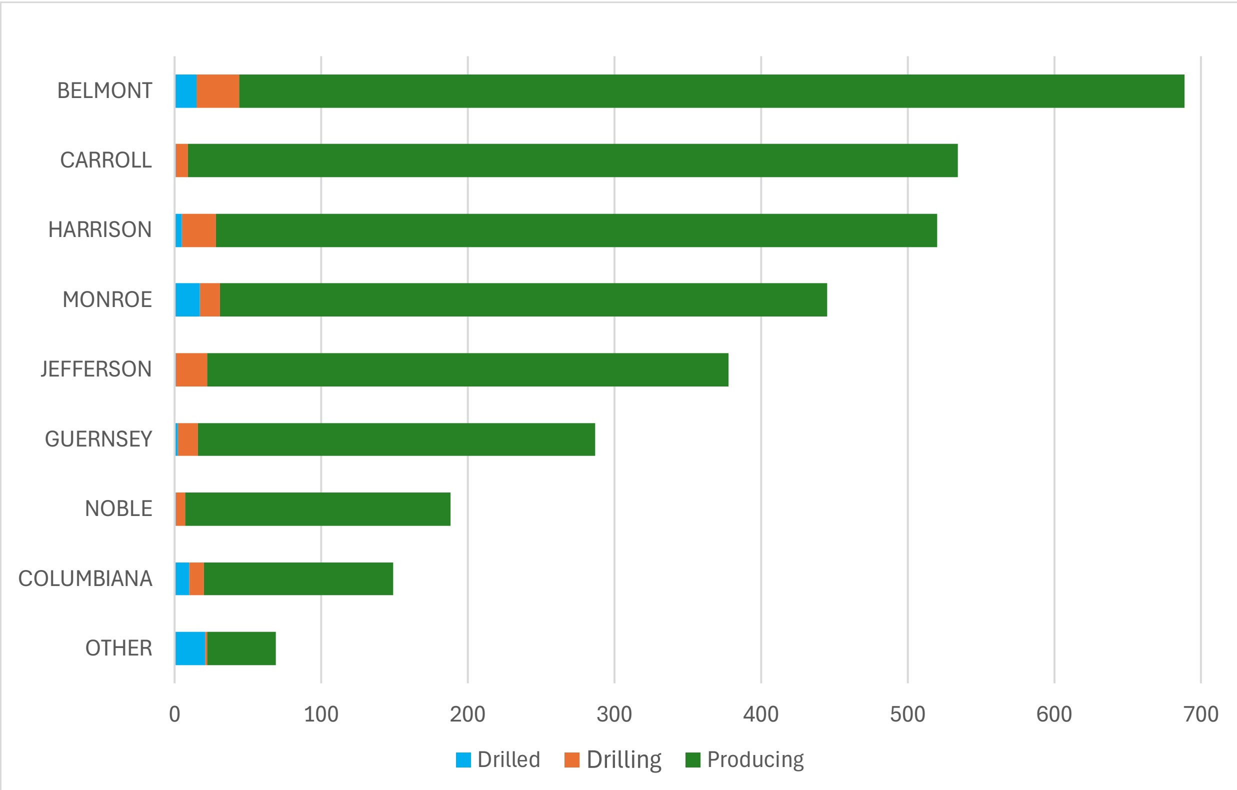


Figure 11: Cumulative Number of Wells by County through June 2023



Source: Ohio Department of Natural Resources (June 2023)

Figure 12: Distribution of Gas Equivalent Production for 2011 through June 2023

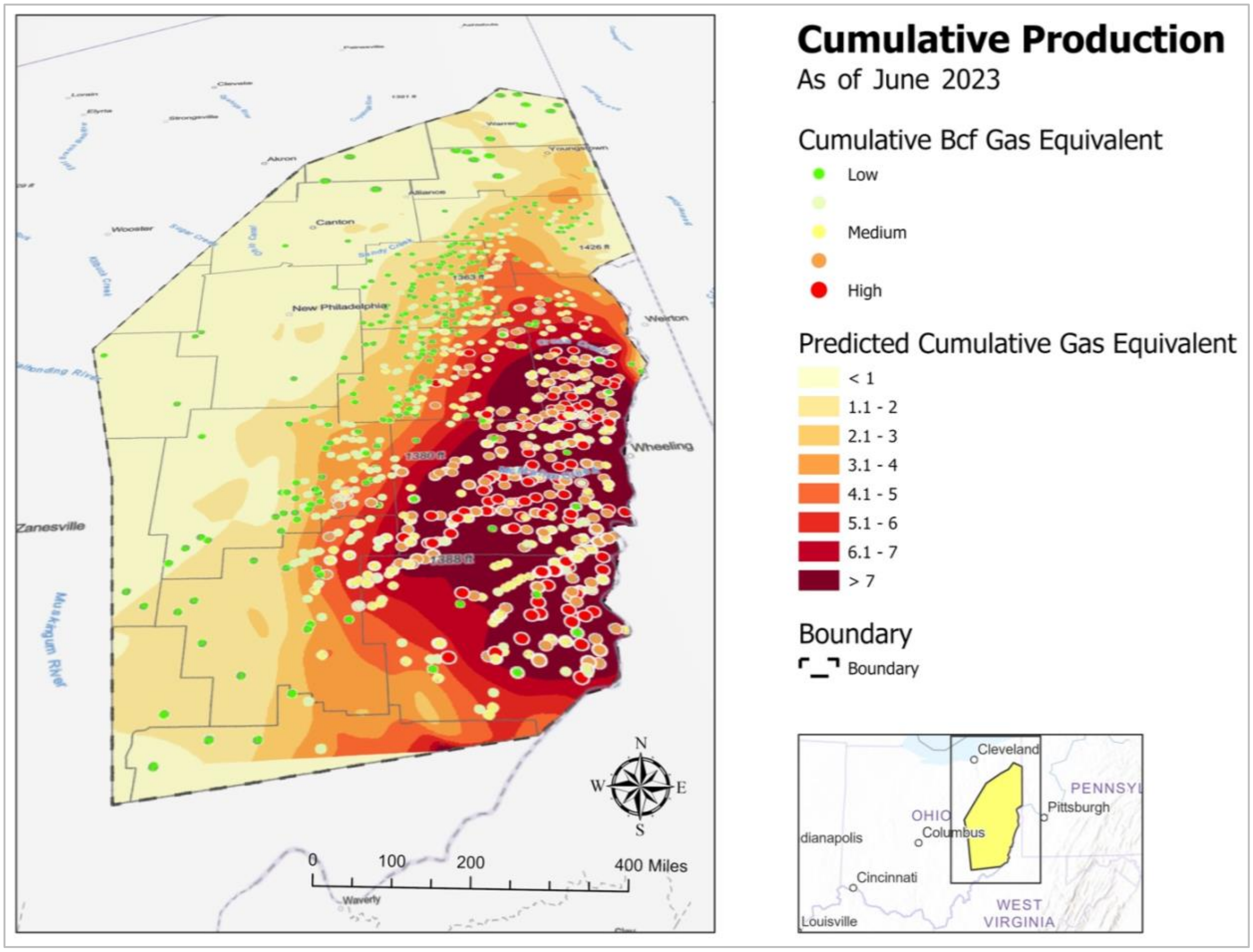
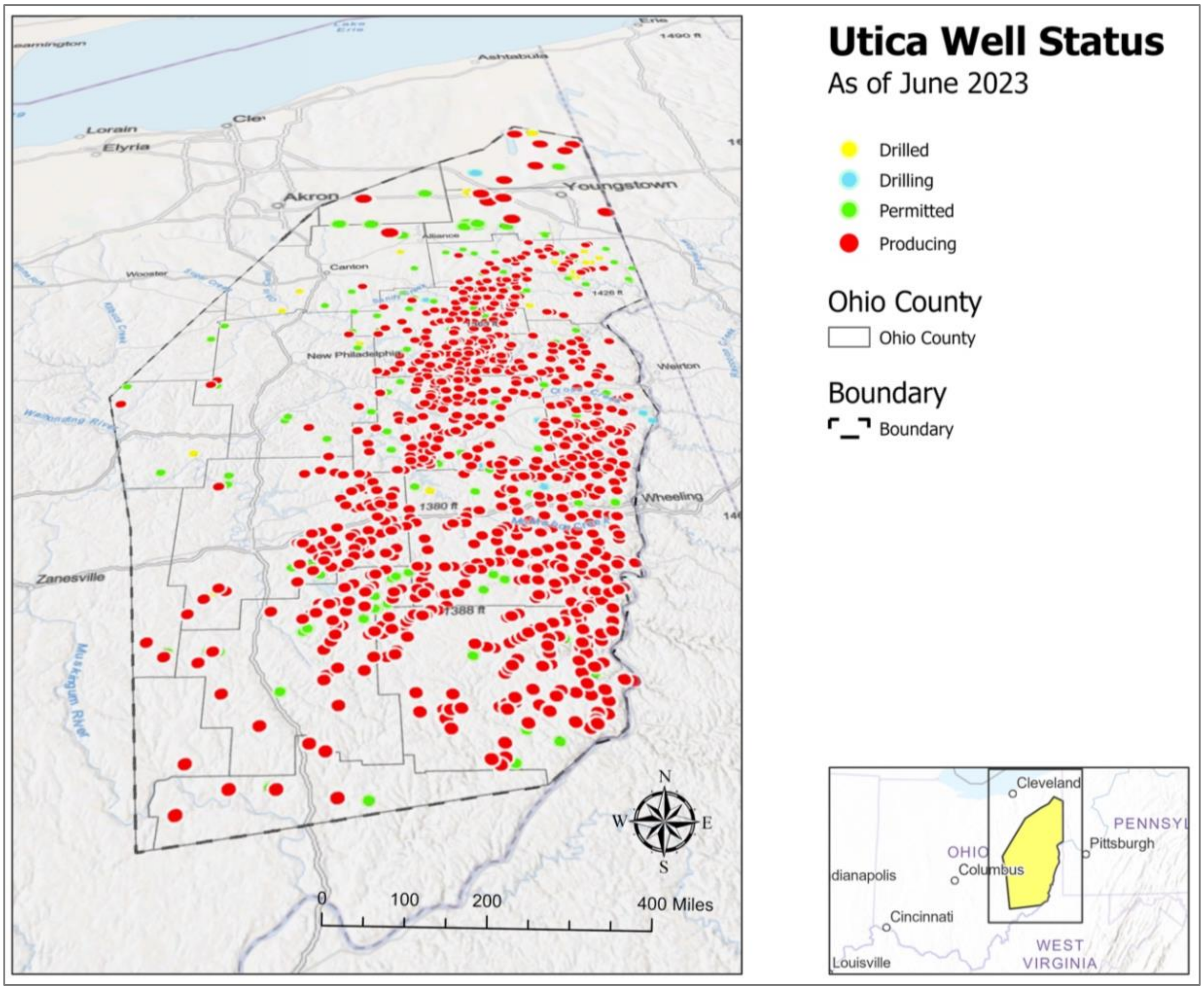


Figure 13: Distribution of Utica Wells by Status as of June 30, 2023



Source: ODNR (2023)

Table 15: Utica Upstream Companies Drilling in Ohio as of June 30, 2023

Operator	Cumulative no. of Wells
EAP OHIO LLC	956
ASCENT RESOURCES UTICA LLC	877
GULFPORT APPALACHIA LLC	444
ANTERO RESOURCES CORPORATION	242
SWN Production (Ohio) LLC	218
RICE DRILLING D LLC	149
HILCORP ENERGY COMPANY	62
INR OHIO LLC	47
CNX GAS COMPANY LLC	46
EQUINOR USA ONSHORE PROPERTIES INC.	42
UTICA RESOURCE OPERATING LLC	37
DIVERSIFIED PRODUCTION LLC	31
EOG RESOURCES INC.	28
PIN OAK ENERGY PARTNERS LLC	25
GEOPETRO LLC	17
GULFPORT ENERGY CORPORATION	12
NORTHWOOD ENERGY CORP	6
Holbrook LLC	4
CHESAPEAKE EXPLORATION LLC	3
DEVON ENERGY PRODUCTION CO LP	3
BRAMMER ENGINEERING INC	2
ECLIPSE RESOURCES I LP	2
EQT PRODUCTION COMPANY	2
SUMMIT PETROLEUM INC	2
AMERICAN ENERGY UTICA LLC	1
BP AMERICA PRODUCTION COMPANY	1
Grand Total	**3,259**

Note: Cumulative Number of Wells are calculated based upon the total number Drilled, Drilling, and Producing. Source: ODNR (June 30, 2023).

Table 16: Total Lease Operating Expenses through June 2023 (in millions)

Year	Period	Production Wells	Lease Operating Expenses for Period ($mm)
2023	Q1 and Q2	3,105	194.3
2022	Q3 and Q4	3,024	150.2
2022	Q1 and Q2	2,886	178.6
2021	Q3 and Q4	2,791	151.8
2021	Q1 and Q2	2,806	205.7
2020	Q3 and Q4	2,705	206.1
2020	Q1 and Q2	2,610	266.2
2019	Q3 and Q4	2,497	262.2
2019	Q1 and Q2	2,273	228.0
2018	Q3 and Q4	2,200	231.0
2018	Q1 and Q2	1,874	191.2
2017	Q3 and Q4	1,818	121.8
2017	Q1 and Q2	1,588	141.3
2016	Q3 and Q4	1,467	101.2
2016	Q1 and Q2	1,355	97.6
2015	Annual	1,034	148.9
2014	Annual	612	88.1
2013	Annual	237	34.1
2012	Annual	82	3.0
2011	Annual	9	0.3
		Total	**3,001.6**

Table 17: Cumulative Utica-Related Upstream Investments in Ohio through June 2023

Estimated Investments	Total Amount
Mineral Rights	$25,861,160,000
Drilling	$31,371,000,000
Roads	$1,136,725,730
Lease Operating Expenses	$3,001,692,909
Royalties	$13,756,258,000
Total	**$75,126,836,639**

Table 18: Cumulative Utica-Related Midstream Investments in Ohio through June 2023

Estimated Investments	Total Amount
Midstream Gathering	$7,988,972,000
Processing Plants	$1,259,300,000
Fractionation Plants	$1,697,360,000
NGL Storage	$261,000,000
Rail Loading Terminals	$150,270,000
Transmission Pipelines	$10,335,682,000
Total	**$21,692,584,000**

Table 19: Cumulative Utica-Related Downstream Investments in Ohio through June 2023

Estimated Investments	Total Amount
Petrochemical Plants and Refineries	$679,443,000
Other Industrial Plants	$760,000,000
Natural Gas Refueling Stations	$81,975,000
Natural Gas Power Plants	$6,442,500,000
Combined Heat and Power (CHP) Plants	$377,370,000
Total	**$8,341,288,000**

APPENDIX B. METHODOLOGY

1. Upstream Methodology.

Investment into the upstream for this fourth report has been broken down into four categories.

a. **Wells and Related Roads.** The first category is investment into wells and includes one-time investments into drilling and road construction related to well development. They were estimated as:

- Drilling:
  - Drilling and completion costs of $11.4 mm/well. [53]
  - Equivalent true vertical depth (TVD) for wells in all counties.
  - Average drilling and completion costs of $800 per lateral foot.[54]
  - Average lateral length of 14,300 ft.[55]
- Roads: average investments - $170,200 per well based on recent OOGA reports after adjusting for inflation.[56]

The number of new wells developed in the Study period, used as a basis for these calculations, were accounted for by subtracting the number of wells in the drilled, drilling and producing categories as of January 1, 2023, from the number existent as of June 30, 2023. This information was downloaded from the ODNR's weekly *Combined Utica/Point Pleasant Shale Permitting Report*.[57]

b. **Lease Operating Expense.** The second estimated upstream cost identified by operators is the "lease operating expense." This includes post-production costs such as the storage, processing and disposal of produced water, among other expenses. Lease operating expenses for Utica wells were estimated to be a production-based $0.167/Mcf-equivalent. This average expense was developed by the Study Team based on analysis of Ascent's and Gulfport's lease

[53] Previous shale reports distinguished between drilling costs for northern counties (Carroll, Harrison, Jefferson, Columbiana, Trumbull, Mahoning and Tuscarawas) and southern counties (Noble, Guernsey, Belmont, Monroe and Washington) based on the assumption that the Utica is deeper in the south, requiring more expensive drilling in over-pressured formations. The Study Team conducted a review of drilling surveys associated with ODNR completion reports for new wells drilled since January 2022 and found a difference in mean true vertical depth between northern and southern counties of less than 500 ft., which would likely not lead to significant cost differences. Also, the same review of drilling surveys indicated that laterals for new wells in southern counties were less than 600 ft. longer on average than horizontal laterals in northern counties, which likewise would probably not lead to significant cost differences.

[54] Estimated drilling costs per lateral foot in the Appalachian Basin based on drilling and completion costs for Ascent Resources, Antero Resources, and Southwestern Energy as reported in quarterly earnings releases and annual 10-K filings for 2023, available at the following: https://www.ascentresources.com/investors; https://www.anteroresources.com/investors; https://ir.swn.com/CorporateProfile/default.aspx.

[55] Calculated using well completion reports obtained from the ODNR's *Ohio Oil & Gas Well Database*.

[56] *See fn 17, supra.*

[57] Ohio Department of Natural Resources. (2023). *Horizontal Wells.* https://ohiodnr.gov/business-and-industry/energy-resources/oil-and-gas-wells/horizontal-wells

operating expenses in the Utica for the first half of 2023 as reported in their quarterly financial statements.[58]

c. Oil and Gas Production Royalties. A third area of upstream investment, royalty calculation, is more complicated. The estimate is based upon the total production over the six-month period and the likely price received for sales of the hydrocarbon during that same period. However, because much of the natural gas has been processed, Ohio Department of Natural Resources production records cannot be readily converted to royalty payments. Accordingly, a number of assumptions are required to estimate the royalties paid. These include estimating the local market conditions at the time hydrocarbons were sold. Royalties were estimated on a per quarter basis for Utica production based upon the hydrocarbon content for a typical Utica well.

To estimate the royalties, the following assumptions were made based upon industry interviews, industry investor presentations, and Energy Information Agency reports:

- Production for each well was similar to that found in the wet gas region, and not the dry gas or condensate regions. This represents the average situation.
- The average production shrinkage after processing was 12%, thereby making the residue gas volume 88% of the total natural gas production. [59]
- The residue energy content was around 1.1 MMBtu/Mcf.[60]
- Residue gas in the Utica was selling at an average price of $2.25/MMBtu for Q1 and $1.56/MMBtu for Q2.[61] These prices were used to estimate royalties.
- Around 44 barrels of liquids were recovered per million cubic feet of gas produced.[62]
- Natural gas liquids were selling for around 30% of the listed price for Marcellus-Utica light crude oil.[63]
- Oil in the Utica region was selling for $66.17 and $63.76 per barrel, on average, during the first and second quarters of 2023, respectively.[64]
- Royalty rates are 20% of gross production.

[58] *See* Ascent Resources' financial reports at https://ascentresources.com/financials. *See also* Gulfport Energy's financial reports at https://www.gulfportenergy.com/investors/sec-filings/quarterly-reports.
[59] Based on industry interviews, experts citing API 12.3, Manual of Petroleum Measurements and Standards.
[60] EIA estimates a conversion rate of 1.037 MMBtu/Mcf (*see* https://www.eia.gov/tools/faqs/faq.php?id=45&t=8). However, industry interviews suggest 1.1 is closer to the average conversion for the Utica Shale.
[61] Reflects average price across the Columbia Gas and Eastern Gas South trading hubs as derived from ICE trade data published by Snyder Brothers Gas Marketing at https://www.snyderbrothersinc.com. Hub prices reflect the delivered price of natural gas and so do not require further deductions for transportation costs. *See* https://www.eia.gov/todayinenergy/detail.php?id=18391
[62] Based on industry data.
[63] Based on industry interviews. Ascent recently indicated that it expects NGL prices to range from between 27.5% and 32.5% of the WTI price for crude oil. *See* Ascent's Q4 2023 earnings release at https://www.ascentresources.com/news/ascent-resources-reports-fourth-quarter-and-full-year-2023-operating-and-financial-results-and-issues-initial-2024-guidance.
[64] *See* Marcellus/Utica prices for light crude at http://ergon.com/prices. More than 95% of Ohio oil production is light crude by API gravity. *See* https://www.eia.gov/petroleum/production/xls/api-history.xlsx

d. New and Renewal Lease Bonuses. Finally, a fourth form of upstream investment was estimated: new and renewal lease bonuses. For this purpose, we assumed that the average new lease or renewal bonus paid was $5000/acre, and that the typical lease has a five-year primary term. In prior studies, based upon the assumption that most undeveloped acreage was in the primary term of the least, we assumed that approximately 20% of the undeveloped acreage identified will need to be renewed each year or is otherwise new.[65] Since this Study covered six months, we assumed that half of this 20% was renewed or new during the Study period. However, as units have developed in the Utica, we have changed this estimate going forward to assume that 25% of the operator's total acreage is in its primary term, and that 20% of this acreage must be renewed or replaced very year (10% for a six-month period). This estimate may be high insofar as companies are not renewing or replacing all their primary term acreage. However, it may also be low insofar as the studies have only identified net acreage for the top six to nine operators in Ohio and may not be capturing all of the non-operator net acreage. (Acreage status is typically reported in company 10-K and other financial statements).

2. Midstream Methodology.

Midstream investments include pipeline construction (intrastate, gathering lines and inter-state), processing plants (compression, dehydration, fractionation, and others), natural gas liquid storage facilities, and railroad terminals and transloading facilities. Midstream expenditures were estimated based upon a combination of midstream company investor reports, media reports, and industry "rules of thumb" obtained from industry interviews, government reports, and industry trade journals. Estimated investments were then compared against investor presentations and other information gleaned from public sources to confirm their accuracy. Interviews were also used to confirm ranges of expenditures.

a. Processing plants. Processing plant information was obtained by searching a wide range of resources including Ohio and US EPA permit databases, news agencies, and company web sites and presentations. For purposes of estimating the investments for midstream processing plants, rules of thumb were developed based upon facility throughput capacities. These rules of thumb were applied to the processing plants that have been built in Ohio, using the throughput capacity estimates cited in permit documents, or made available from public literature. Likewise, rules of thumb based upon throughput capacity were used to estimate investments downstream of the processing plants, such as storage facilities and loading terminals. Dehydration processing plants were estimated using average cost per Mcf capacity for similarly designed and recently built plants in the Appalachian region.

Compressor station investments were calculated based on the horsepower rating listed in Ohio EPA air permit data and estimated construction costs per horsepower of $5,251 for the Midwest

[65] This estimate was confirmed through industry interviews. New operator undeveloped acreage reports are likely to be made available over time that may suggest these estimates could be either too high or too low.

Region as projected by the Interstate Natural Gas Association of America (INGAA) for 2023 after adjusting for inflation.[66]

The approximate capital cost for TEG dehydration units based on throughput was obtained from Carroll's *Natural Gas Hydrates: A Guide for Engineers* (2014, 3rd ed.). Facilities receiving a final permit-to-install or permit-to-install-and operate were assumed to be constructed during the same 6-month period in which the permit was issued by the Ohio EPA.

The following assumptions were used to estimate midstream-related investments:

- Processing Plants.
  - $400,000 per MMcf/d throughput
  - $80 MM per 200 MMcf/d plant (typical skid size)
- Fractionation Plants: $3,542 per bbl/d[67]
- Storage Tankage: $80 MM for 1 Bcf/d throughput
- Rail Loading Terminals: $40 MM for 1 Bcf/d throughput

b. Pipelines. Pipeline investments were estimated by applying "inch-mile" cost estimates to known pipeline diameter and length for both inter- and intrastate projects. Interstate pipeline diameters and mileage can be determined from Federal Energy Regulatory Commission data. These estimates were confirmed from investor presentations, when available. Intrastate mileage and diameter were determined using data for gathering system construction that was obtained from the Public Utilities Commission of Ohio.

For this report, up-to-date cost projections for natural gas transmission and gathering line pipelines, per inch-mile, was obtained from the INGAA. The estimated cost for natural gas pipelines for the Midwest Region as used in this analysis was $267,403 per inch-mile, which included labor, raw materials, and permitting costs, as projected by the INGAA for 2023 after adjusting for inflation.[68]

No investments into distribution lines were included in the Study since it is assumed that these have not grown as a direct result of shale development. For pipelines carrying liquids, the

[66] *See* The INGAA Foundation, Inc. (2018). *North America Midstream Infrastructure through* 2035. https://ingaa.org/wp-content/uploads/2018/06/34703.pdf. INGAA's projections for midstream infrastructure costs are in 2016 dollars. These projections were converted to 2023 dollars using the Bureau of Labor Statistics' Producer Price Index for *Other Pipeline Transportation* (available at https://fred.stlouisfed.org/series/PCU48694869).

[67] The Study Team reviewed the published investment costs and throughput capacities of eight different fractionation facilities that have been developed since 2018, all of which are in Texas. The assumed unit cost for fractionation reflects the median investment per barrel of processing capacity per day for these eight facilities. *See* the following examples: Targa Resources Inc.'s Mont Belvieu fractionation facilities (https://www.naturalgasintel.com/targa-building-two-new-fractionation-trains-at-mont-belvieu/); Phillip 66's Sweeny fractionation facilities (https://s22.q4cdn.com/128149789/files/doc_presentations/2019/11/Investor-Day-Slides-for-Website-11.06.2019-vF.pdf).

[68] *See fn 65, supra*.

investment assumption is that expenditures will be comparable to those seen for gas pipelines. These were also corroborated by industry investor reports.

3. Downstream Methodology.

For estimating downstream expenditures, the Study Team relied upon publicly available reports gathered from news media, trade association publications, company websites and investor presentations. The Study Team also used interviews, and Ohio EPA permits and public notices to identify projects and support investment estimates. Search terms included identified company names, and key words associated with specific facility types and industries.

As of this report, downstream investment is categorized into eight categories:

- Natural Gas Power Plants
- Combined Heat and Power Plants
- Ethane Cracker Plants
- Methanol Plants
- Refineries
- Natural Gas refueling stations
- Petrochemical Plants
- Other industrial plants with natural gas inputs

NAICS codes used to generate keywords for searches included the following:
3251 – Basic Chemical Manufacturing
3252 – Resin, Synthetic Rubber, and Artificial and Synthetic Fibers and Filaments Manufacturing
3253 – Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing
3255 – Paint, Coating, and Adhesive Manufacturing
3259 – Other Chemical Product and Preparation Manufacturing
3261 – Plastics Product Manufacturing

Downstream activities include the deployment of processes that turn hydrocarbons— natural gas (methane) and natural gas liquids (ethane, propane, butanes)—into higher-valued fuels and petrochemicals. Shale gas may be monetized into numerous resulting value-added products. Figure 14 shows the primary intermediates and products that can be manufactured from the main hydrocarbon components in shale gas as part of downstream production.[69]

[69] *See* U.S. Department of Energy. (June 2020). *The Appalachian Energy and Petrochemical Renaissance: An Examination of Economic Progress and Opportunities*. https://www.energy.gov/sites/prod/files/2020/06/f76/Appalachian%20Energy%20and%20Petrochemical%20Report_063020_v3.pdf

Figure 14: Shale/Natural Gas Value Chain for Petrochemicals