Cleveland State University
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Prepared for:
JOBSOHIO

SHALE INVESTMENT DASHBOARD IN OHIO Q1 AND Q2 2021

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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 2021. 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 2021 can be summarized as follows:

Total Estimated Upstream Utica Investment: January – June 2021

Lease Renewals and New Leases	$116,565,000
Drilling	$876,600,000
Roads	$4,440,000
Lease Operating Expenses	$205,740,000
Royalties	$1,017,983,000
Total Estimated Upstream Investment	**$2,221,328,000**

Total Estimated Midstream Investment: January – June 2021

Gathering Lines	$29,100,000
Gathering System Compression and Dehydration	$13,800,000
Total Estimated Midstream Investment	**$ 42,900,000**

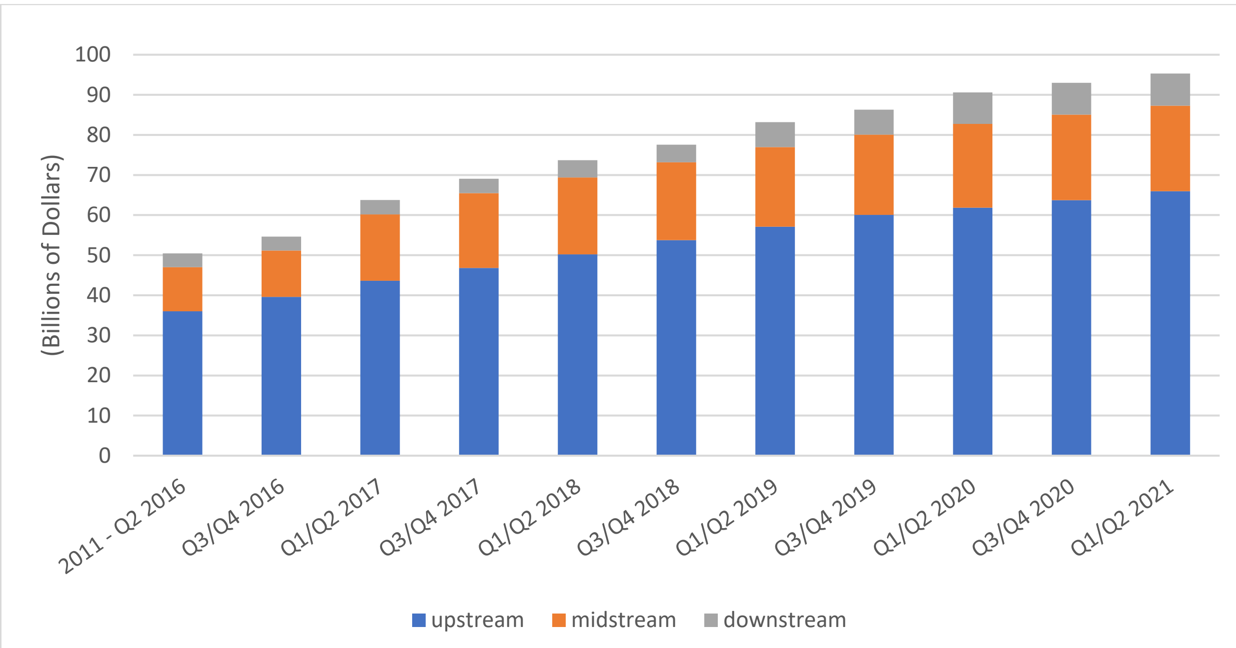
Total Estimated Downstream Investment: January - June 2021

Natural Gas Refueling Stations	$31,300,000
Petrochemicals (Including Refineries)	$16,378,000
Total Estimated Downstream Investment	**$47,678,000**

[1] The ten previous reports on shale investment in Ohio up to December 2020 can be found at https://engagedscholarship.csuohio.edu/urban_enpolc/

Total investment from January through June 2021 was approximately $2.3 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 2021 is estimated to be around $95.3 billion. Of this, $65.9 billion has been in upstream, $21.4 billion in midstream, and $8.0 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.

Figure 1. Cumulative Shale Investment in Ohio Over Time



Overall upstream investments were up by about $361 million in the first half of 2021 compared to the second half of 2020, reflecting higher royalty earnings due to higher oil and gas prices. As determined from Ohio Department of Natural Resources Division of Oil and Gas (ODNR) data for shale well drilling, 74 new wells were drilled during the first and second quarters of 2021, 6 fewer than the number drilled in the second half of 2020. ODNR production data also indicated that the total volume of gas-equivalent shale production in the first half of 2021 was 7% less than overall production in the second half of 2020. Jefferson County had the highest number of new wells with 36, followed by Harrison and Monroe Counties, which had 13 and 10 new wells, respectively. We noted in our last report that Belmont county lost its top ranking among Ohio counties in new well development since the second half of 2018. The county dropped even lower in the first of half of 2021, with only six new wells drilled. No other county had more than five new wells drilled for the first half of 2021.

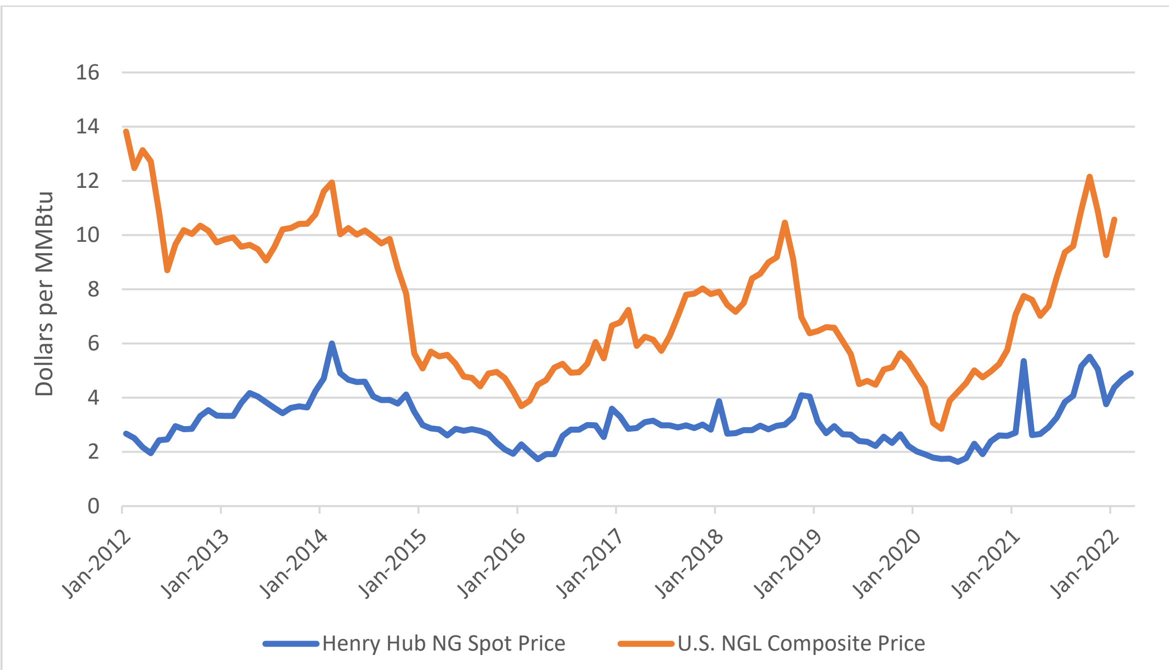
Ascent and Encino were the top producers for Q1 and Q2 of 2021, having produced 389 and 196 billion cubic feet equivalent (Bcfe), respectively. Gulfport was third in production at 173 Bcfe.

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

Rice Drilling and Eclipse each produced 109 Bcfe. Equinor took Antero's place in the top six producers in Ohio, with Equinor at 42 Bcfe, which was 2 Bcfe higher than the latter's production. The top six companies made up around 89% of the total production for the first half of 2021.

The first half of 2021 saw a steep decline in midstream investment compared to the second half of 2020, with no major pipeline development or processing capacity expansion as the COVID pandemic unfolded. However, more recently rising commodity prices approaching 10-year highs (*see* Figure 2) will likely put upward pressure on investment spending across all natural gas segments. The midstream spending that did occur in the first half of 2021 included gathering system buildout for pipelines ($29.1 million) and compression ($13.8 million).

Figure 2. Monthly Average Natural Gas and NGL Prices Since 2012



Data Source: EIA (NYMEX)

In downstream developments, two compressed natural gas refueling stations (representing a combined investment of $31.3 million) were installed by transit agencies in Cleveland and Columbus. Additional capacity expansion occurred at Marathon's oil refinery in Canton, totaling an estimated $15.8 million. There is no definite timeframe for an investment decision on PTTGC America's ethane cracker in Belmont County, but the company continues to buy real estate and do preparatory work near the proposed site, including purchases of $0.5 million in property during the Study period.

1. INTRODUCTION

This is the eleventh CSU study reporting investment resulting from oil and gas development in Ohio related to the Utica and Point Pleasant formations (hereinafter, the "Utica").[3] This analysis looks at investments made in Ohio between January 1 and June 30, 2021, 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.

This eleventh 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 2021.[4] 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 74 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, 2021.[5] This represents a 7.5%

[3] 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.

[4] *See fn 1, supra*.

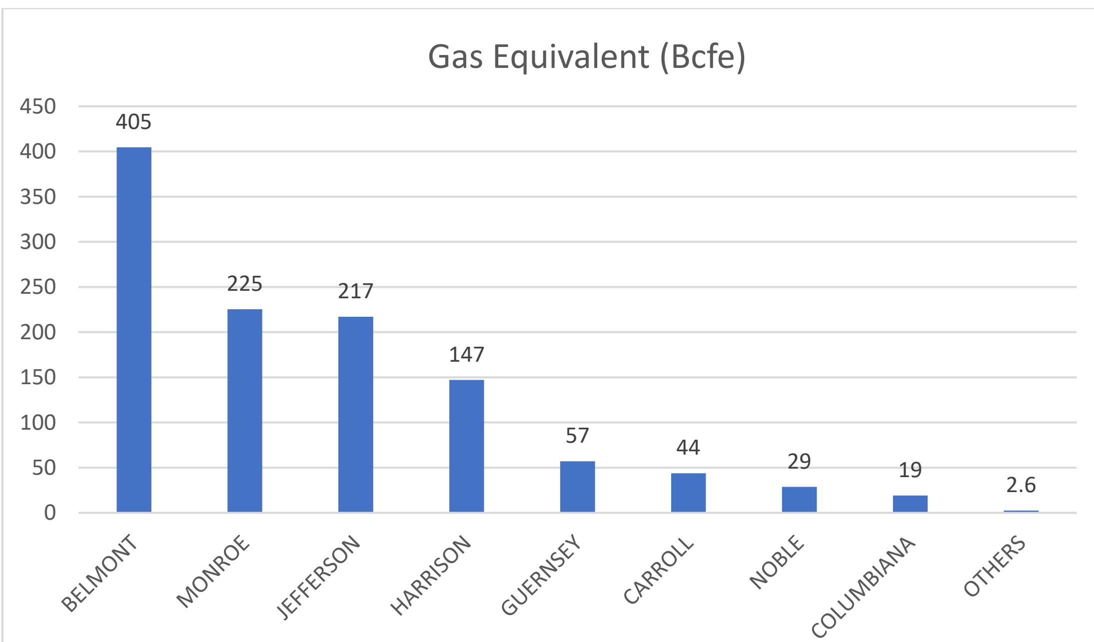
[5] The number of new wells was determined using ODNR Cumulative Permitting Activity reports for the beginning and end of the 6-month period (*see* http://oilandgas.ohiodnr.gov/shale). Wells are assigned an American Petroleum Institute API number, which is included in the ODNR reports. Wells were considered 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.

decrease in new well development compared to the second half of 2020. The total number of producing wells in the Utica was 2,700 on July 3, 2021, a 2.3% increase from the end of December 2020. Total shale-related oil and gas production in billion cubic feet equivalent (Bcfe) for this period was 1,146 Bcfe, led by Belmont County with 405 Bcfe. Monroe County was second with 225 Bcfe, followed by Jefferson County with 217 Bcfe.[6]

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 2021 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 (over ninety-eight percent) 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 2021 is set forth by county and operator in Figures 3 and 4 below. Total cumulative production in billions of cubic feet equivalent (Bcfe) by county and by operator through June 2020 can be found in Appendix A as Figures 10 and 11.

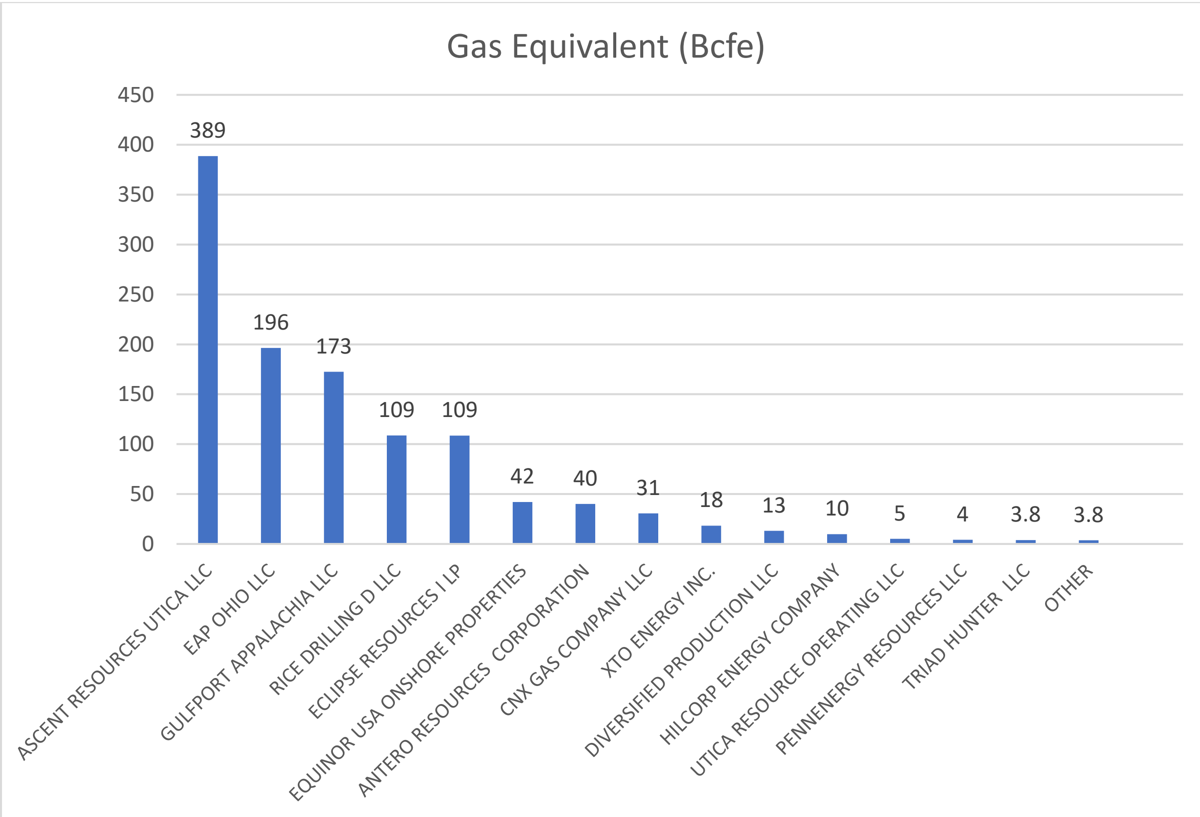
Figure 3: Production by County for Q1 and Q2 of 2021



Data Source: ODNR (2021).

[6] 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).

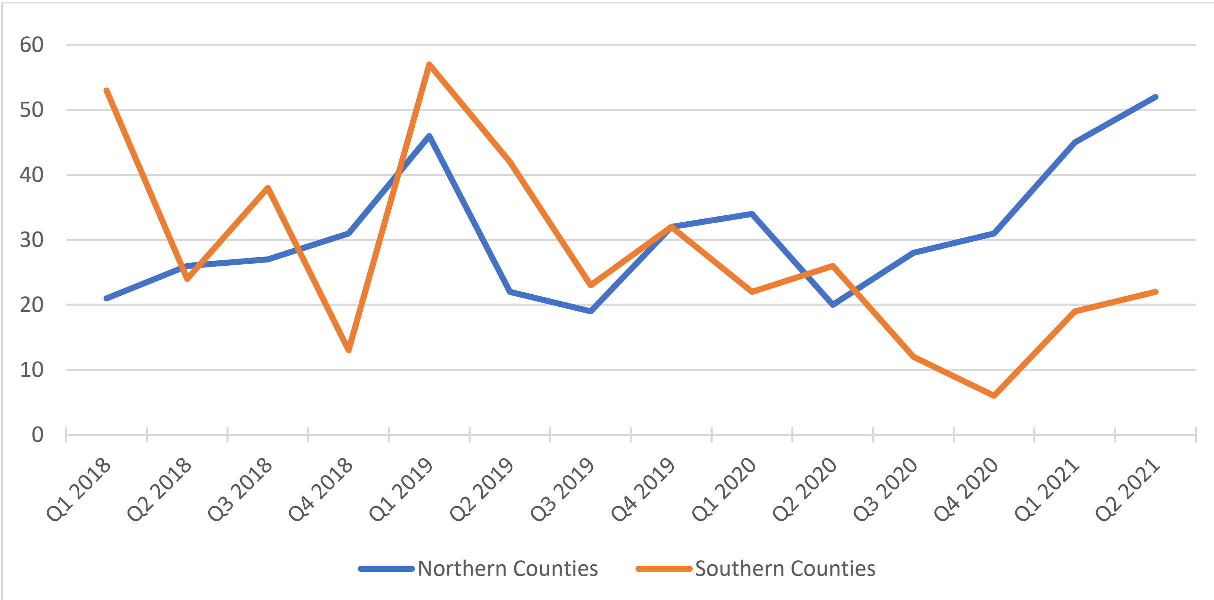
Figure 4: Production by Operator for Q1 and Q2 of 2021



Data Source: ODNR (2021).

Over the last few reports, we have tracked the relatively higher growth in shale well development for more northerly counties than southern ones, as indicated by ODNR permitting activity for Utica wells. A review of these permits suggests that this trend continued in the first half of 2021. As shown in Figure 5, by Q2 2021 there were more than twice as many permits issued for Utica oil and gas wells in the most active northern counties compared to the number of permits issued for the most active southern counties. (The four most active northern counties for drilling and production have been Jefferson, Harrison, Columbiana, and Carroll, while the four most active southern counties have been Belmont, Monroe, Guernsey, and Noble). As a result, we can expect that drilling investment will be moving principally to the northern counties in the next two years.

Figure 5. Permits Issued for Shale Wells in Northern and Southern Counties Since 2018



Data Source: ODNR (2021).

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 quarter of 2021, 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 2021. Figure 6 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)
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	4	1492	362,107,422	3,568,077	382,364,866	-0.2
2016	3	1442	360,681,356	3,954,095	383,057,580	5.9
2016	2	1382	334,257,982	4,839,792	361,646,365	0.3
2016	1	1328	329,537,838	5,485,854	360,582,286	7.0
2015	4	1248	301,486,508	6,248,451	336,846,492	39.1
2015	3	989	216,974,492	4,439,258	242,096,253	-4.5
2015	2	992	221,862,582	5,578,255	253,429,927	21.5
2015	1	907	183,585,256	4,432,195	208,667,049	12.8
2014	4	810	164,815,008	3,558,836	184,954,459	25.7
2014	3	688	130,282,395	2,984,534	147,171,872	45.0
2014	2	535	87,773,834	2,422,179	101,480,943	30.1
2014	1	415	67,095,693	1,928,076	78,006,674	53.5
2013	4	371	42,693,774	1,433,731	50,807,259	24.7
2013	3	269	33,255,706	1,323,812	40,747,160	126.2
2013	2	186	14,863,645	556,437	18,012,520	79.1
2013	1	117	8,237,177	321,439	10,056,202	-38.8
2012	ANNUAL	82	12,831,292	635,874	16,429,703	481.9
2011	ANNUAL	9	2,561,524	46,326	2,823,683	--
Total		**54,199**	**12,950,501,092**	**144,854,239**	**13,768,599,775**	--

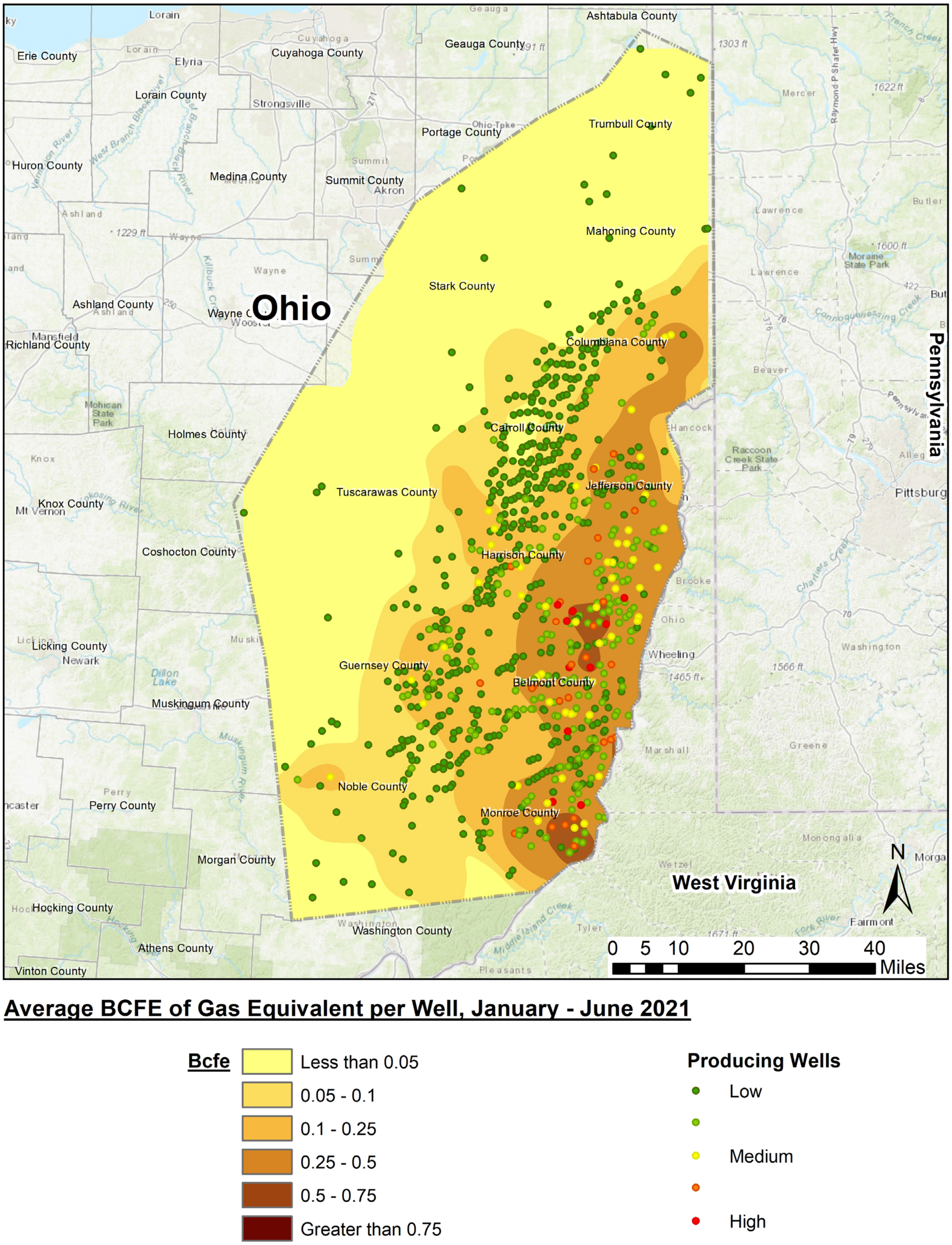
Source: ODNR (2021).

Table 2: Production by County for January - June 2021

County	Gas (Mcfe)	Oil (bbl)	Gas Equivalents (Mcfe)	Production Wells
BELMONT	403,116,375	273,211	404,637,040	618
CARROLL	38,752,877	914,099	43,840,661	481
COLUMBIANA	19,068,872	12,708	19,139,603	89
COSHOCTON	14,197	127	14,904	1
GUERNSEY	36,986,946	3,611,158	57,086,290	249
HARRISON	129,041,642	3,263,267	147,204,660	445
JEFFERSON	217,116,206	1	217,116,212	286
MAHONING	636,263	4,511	661,371	12
MONROE	223,806,542	293,907	225,442,399	417
MORGAN	66,188	2,459	79,875	2
MUSKINGUM	206,418	31,135	379,712	2
NOBLE	27,151,425	273,772	28,675,213	175
PORTAGE	29,917	172	30,874	1
STARK	53,288	343	55,197	2
TRUMBULL	181,430	404	183,679	7
TUSCARAWAS	170,113	9,481	222,883	7
WASHINGTON	903,620	6,748	941,179	11
WAYNE	38,230	-	38,230	1
Total	1,097,340,549	8,697,503	1,145,749,981	2,806

Source: ODNR (2021).

Figure 6: Distribution of Gas Equivalent Production for January - June 2021



Of the 2,922 total wells identified from the ODNR records for cumulative drilling activity as of June 2021, 116 were in the process of drilling, 106 wells had been drilled and were awaiting markets, and 2,700 were in the production phase.[7] (*See* Table 3, Ohio Utica Well Status.) Belmont County continued to lead in total wells (*see* Table 4).

Table 3: Ohio Utica Well Status as of June 2021

Well Status	No. of Wells
Drilled	106
Drilling	116
Producing	2,700
Total	**2,922**

Source: ODNR (2021)

Table 4: Well Status by County (June 2021)

County	Drilled	Drilling	Producing	Total
BELMONT	22	14	600	636
CARROLL	7	2	473	482
HARRISON	14	18	434	466
MONROE	17	23	371	411
JEFFERSON	8	29	272	309
GUERNSEY	4	11	246	261
NOBLE	1	6	174	181
COLUMBIANA	12	11	84	107
MAHONING	1	0	12	13
TRUMBULL	3	1	7	11
WASHINGTON	0	0	11	11
PORTAGE	7	1	1	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	**106**	**116**	**2,700**	**2,922**

[7] 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.

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. We continued to differentiate between northern counties ($11.4 million per well) and southern counties ($12.9 million per well). This has been confirmed by recent drilling surveys that indicate an extra 1,700 of lateral length on average for wells drilled in southern counties.

This section covers upstream investments between January and June 2021. Cumulative upstream investments to date in Ohio, including 2011 through the first half of 2021, are set forth in Table 16 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 36 new wells and an investment of around $412.6 million between January and June 2021. Harrison and Monroe counties were second and third, with 13 and 10 new wells, to go along with $149.0 million and $129.6 million invested, respectively. *See* Table 5. Road-related investments for this version of the Shale Investment Dashboard reflect the average road costs per well determined from a 2017 report by Energy-In-Depth describing Road Use Maintenance Agreements (RUMAs) that companies have entered into with local governments for infrastructure improvements since Utica production began in 2011.[8] The data for that report were obtained directly from the engineer's office for the top eight oil and natural gas producing counties in Ohio.

EAP Ohio LLC was the leading operator-investor during the six-month period, with 30 new wells and an estimated $343.8 million. Ascent Utica Resources LLC, 75% of whose new wells were in the lower cost, more northerly counties, recorded the second highest investment, with 24 new wells and an estimated $284 million investment. Gulfport Appalachia LLC and Gulfport Energy Corporation invested $58.8 million and $51.8 million in 5 and 4 wells, respectively. (*See* Table 6.)

[8] *See* "Ohio's Oil & Gas Industry Road Improvement Payments." Prepared by The Ohio Oil & Gas Association and Energy in Depth. https://www.energyindepth.org/wp-content/uploads/2017/11/2017-Utica-Shale-Local-Support-Series-Ohios-Oil-and-Gas-Industry-Road-Payments.pdf

Table 5: Estimated Upstream Shale Investment by County, January – June 2021

County	No. of New Wells	Drilling ($)	Roads ($)	Total Amount ($)
JEFFERSON	36	$410,400,000	$2,160,000	$412,560,000
HARRISON	13	$148,200,000	$780,000	$148,980,000
MONROE	10	$129,000,000	$600,000	$129,600,000
BELMONT	6	$77,400,000	$360,000	$77,760,000
GUERNSEY	4	$51,600,000	$240,000	$51,840,000
COLUMBIANA	2	$22,800,000	$120,000	$22,920,000
CARROLL	1	$11,400,000	$60,000	$11,460,000
MUSKINGUM	1	$12,900,000	$60,000	$12,960,000
NOBLE	1	$12,900,000	$60,000	$12,960,000
Total	**74**	**$876,600,000**	**$4,440,000**	**$881,040,000**

Source: The Authors (2021)

Table 6: Estimated Upstream Shale Investment in Ohio by Company, January – June 2021

Operators	No. of Wells	Drilling ($)	Roads ($)	Total Amount ($)
EAP OHIO LLC	30	$342,000,000	$1,800,000	$343,800,000
ASCENT RESOURCES UTICA LLC	24	$282,600,000	$1,440,000	$284,040,000
GULFPORT APPALACHIA LLC	5	$58,500,000	$300,000	$58,800,000
ANTERO RESOURCES CORPORATION	4	$51,600,000	$240,000	$51,840,000
GULFPORT ENERGY CORPORATION	4	$51,600,000	$240,000	$51,840,000
ECLIPSE RESOURCES I LP	3	$38,700,000	$180,000	$38,880,000
ARTEX ENERGY GROUP LLC	2	$25,800,000	$120,000	$25,920,000
DIVERSIFIED PRODUCTION LLC	2	$25,800,000	$120,000	$25,920,000
Total	**74**	**$876,600,000**	**$4,440,000**	**$881,040,000**

Source: The Authors (2021)

2. Lease Operating Expenses.

Post-production investments have been estimated on a half-year basis, assuming an average cost of around $12,700/month/well. This estimate is based upon recent operator reports.[9] These investments are set forth below. Consistent with total number of production wells, Belmont County and Carroll County led the lease operating expense investment, with an estimated $45.7 million and $36.0 million invested, respectively.

[9] The per-month rule-of-thumb for lease operating expenses per producing well for this report is based on Ascent's unit lease operating expenses for 2020 as reported in company financial statements.

Table 7: Estimated Lease Operating Expenses for January – June 2021 by County

County	Production Wells	Lease Operating Expense for Period
BELMONT	600	$45,720,000
CARROLL	473	$36,042,600
HARRISON	434	$33,070,800
MONROE	371	$28,270,200
JEFFERSON	272	$20,726,400
GUERNSEY	246	$18,745,200
NOBLE	174	$13,258,800
COLUMBIANA	84	$6,400,800
MAHONING	12	$914,400
WASHINGTON	11	$838,200
TUSCARAWAS	7	$533,400
TRUMBULL	7	$533,400
MORGAN	2	$152,400
MUSKINGUM	2	$152,400
STARK	2	$152,400
WAYNE	1	$76,200
COSHOCTON	1	$76,200
PORTAGE	1	$76,200
Total	**2,700**	**$205,740,000**

Table 8: Estimated Lease Operating Expenses for January - June 2021 by Operator

Operator	Production Wells	Lease Operating Expense for Period
EAP OHIO LLC	837	$63,779,400
ASCENT RESOURCES UTICA LLC	611	$46,558,200
GULFPORT APPALACHIA LLC	399	$30,403,800
ANTERO RESOURCES CORPORATION	222	$16,916,400
ECLIPSE RESOURCES I LP	181	$13,792,200
RICE DRILLING D LLC	138	$10,515,600
XTO ENERGY INC.	58	$4,419,600
CNX GAS COMPANY LLC	46	$3,505,200
PENNENERGY RESOURCES LLC	40	$3,048,000
EQUINOR USA ONSHORE PROPERTIES INC.	38	$2,895,600
UTICA RESOURCE OPERATING LLC	33	$2,514,600
HILCORP ENERGY COMPANY	23	$1,752,600
PIN OAK ENERGY PARTNERS LLC	23	$1,752,600
DIVERSIFIED PRODUCTION LLC	21	$1,600,200
GEOPETRO LLC	16	$1,219,200
ARTEX ENERGY GROUP LLC	8	$609,600
NORTHWOOD ENERGY CORP	6	$457,200
Total	**2,700**	**$205,740,000**

3. Royalties.

Royalty investments have been estimated on a per quarter basis, assuming the formula set forth in Appendix B. Total estimated royalties spent on Ohio properties between January and June 2021 were around $1 billion, more than twice the royalty investment in the second half of 2020. 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 $3.66/MMBtu during the first half of 2021, up from $1.27 in the second half of 2020.[10] Regional oil prices increased from an average of $47.91/bbl during the first quarter of 2021 to $56.14/bbl for the second quarter.[11] For comparison, regional oil prices averaged $31.15 and $33.03 per barrel in the third and fourth quarters of 2020, respectively.

Table 9: Total Royalties from Oil, January – June 2021 (in millions)

Year	Quarter	Oil Price $/bbl	Oil Royalty (20%) $/bbl	Royalty ($mm)
2021	2	$56.14	$11.23	$46.64
2021	1	$47.91	$9.58	$43.54
			Subtotal	**$90.18**

Table 10: Total Royalties from Residue Gas, January – June 2021 (in millions)

Year	Quarter	Residue Gas Price $/Mcf	Residue Gas Royalty (20%) $/Mcf	Royalty ($mm)
2021	2	2.96	$0.59	$286.53
2021	1	5.08	$1.02	$490.55
			Subtotal	**$777.08**

Table 11: Total Royalties from Natural Gas Liquids, January – June 2021 (in millions)

Year	Quarter	NGL Price $/bbl	NGL Royalty (20%) $/bbl	Royalty ($mm)
2021	2	16.84	$3.37	$81.39
2021	1	14.37	$2.87	$69.33
			Subtotal	**$150.73**

[10] Reflects average Appalachia regional natural gas prices over the respective periods. *See* https://www.naturalgasintel.com/appalachian-consolidation-continues-as-west-virginia-natural-gas-trade-groups-merge/.

[11] *See* https://ergon.com

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 85% of the Utica wells to date, and it is assumed that they likewise control over 85% 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.[12] 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 19% 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, and 10% over the half-year study period (i.e., 5% of total acreage each year).

[12] *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. *See e.g.,* Chesapeake Energy Corporation. (2018). 2017 annual report. https://www.sec.gov/Archives/edgar/data/0000895126/000089512618000060/chk-20171231_10k.htm. 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.

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 conservative number in the Utica, and therefore likely to still be conservative for renewals of older leases. But there is evidence that in 2020 new lease bonus rates were depressed due to sustained low natural gas prices. Nevertheless, the most recent publicly reported information on lease bonuses suggests, however, that $5000/acre continues to be a reasonable estimate. In late 2019, for example, Belmont County leased county-owned mineral rights for $5750/acre for a 5-year primary term.[13]

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 will be under reported.

Table 12: Total Estimated Investments into New Leases and Lease Renewals January – June 2021 (in millions)

Operator	Acreage not held for production	Estimated Bonus Investment ($mm)
ANTERO RESOURCES CORPORATION[14]	21,590	7.6
ASCENT RESOURCES UTICA HOLDINGS, LLC	84,232	33.4
EAP OHIO LLC[15]	246,831	28.9
Southwest Energy Company[16]	58,840	13.8
GULFPORT ENERGY CORPORATION	48,216	18.7
Rice Drilling D LLC (EQT)	35,755	14.2
Total	**495,464**	**116.6**

[13] *See* Belmont County Board of County Commissioner meeting minutes for December 18, 2019. https://belmontcountycommissioners.com/wp-content/uploads/bsk-pdf-manager/2020/01/December-18-2019-2.pdf

[14] While Antero's FY2021 10-K did not distinguish Ohio Utica Shale from Marcellus Shale for the company's holdings in the Appalachian basin, its FY2019 10-K did. For FY2019, 90,814 of the company's 541,447 total net acres were in Ohio, or 16.8%. Applying this percentage to Antero's Appalachian basin holdings for FY2021 of 501,656 total net acres yields an estimated 84,140 total net acres in Ohio for 2021. According to the company's FY2021 10-K, 18% of its net Appalachian Basin acreage was not held by production.

[15] Fitch Solutions' coverage of privately held EAP's successful $700 million bond offering in 2021 indicates that the operator has 300,000 net Utica acres. *See* https://www.fitchratings.com/research/corporate-finance/fitch-affirms-encino-acquisition-partners-llc-idr-at-b-outlook-revised-to-stable-20-04-2021

[16] Southwest's acreage in the Appalachian Basin—encompassing parts of Ohio, Pennsylvania, and West Virginia—was not itemized by state in its FY2021 10-K report. The company's Ohio acreage was estimated by importing a map of its Appalachian operations into a geographic information system (GIS) software application. *See* https://www.swn.com/operations/appalachia/

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.

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 2021. 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 Gathering System Investment, January – June 2021

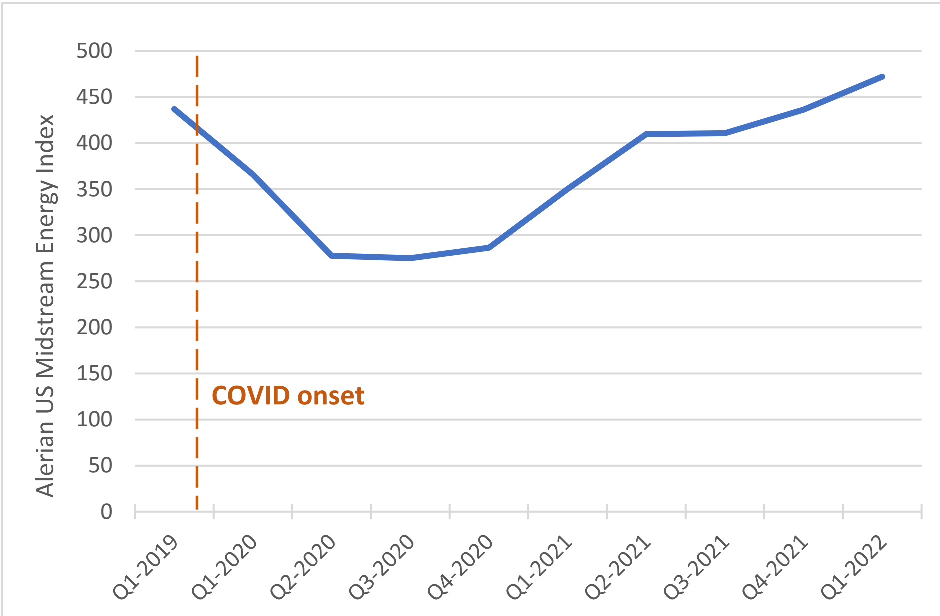
Company	Additions to Infrastructure	Total Amount ($mm)
Utica Gas Services (Williams)	• 4.53 miles of 12.75" pipeline • 1.90 miles of 10.75" pipeline • 0.23 miles of 8.63" pipeline	$15.2
Antero Midstream Partners LP	• 1.97 miles of 20" pipeline	$7.4
Blue Racer Midstream LLC	• 2.77 miles of 8.63" pipeline	$4.5
Cardinal Gas Services (Williams)	• 1.07 miles of 8.63" pipeline • 0.15 miles of 10.75" pipeline	$2.0
Diversified Energy	• 3,550 hp of compression at Moonraker Pad, Monroe County	$13.8
	Total	**$42.9**

Source for Gathering Line Mileage and Diameter Data: PUCO Gathering Construction Reports (2021)

Midstream investments were down significantly during the first half of 2021, totaling around $43 million. By comparison, $400 million in midstream investment was tracked for the second half of 2020. However, this was likely the trough of the COVID-related downturn for this segment. On a return basis, U.S. midstream companies have largely recovered and returned to near pre-pandemic levels (*see* Figure 7 below).[17]

[17] The Alerian US Midstream Energy Index (symbol: AMUS) is a broad-based composite of US energy infrastructure companies. For a list of these constituent companies, *see* https://www.alerian.com/indexes/amus-index

Figure 7. U.S. Midstream Company Performance



Data Source: Alerian via Google Finance

The improvement to company returns, of course, does not necessarily mean that capital spending has recovered. However, midstream infrastructure investment does seem to have stabilized as of late. Figure 8 below shows the average growth in capital expenditures for 2020, 2021, and 2022 based on actual spending for the first two years and budgeted spending for the current year for midstream companies operating in the Utica with available Capex guidance.[18] (This change in Capex growth reflects operations both inside and outside the Utica for these companies.) The current year promises to be the first since 2019 to see positive growth for midstream infrastructure investments. This increased spending will largely be focused on small projects to build out infrastructure, increase asset integrity, reduce emissions, and improve efficiencies.[19] In Ohio, for example, this includes more than twice the spending on gathering system compression in the second half of 2021—which will be included in the next shale dashboard—compared to the first.[20] Beyond this, larger capital projects could still materialize under more stable macroeconomic conditions, including hundreds of millions of dollars in NGL storage.[21] Cumulative midstream investments through the end of June 2021 are set forth in Table 17 in Appendix A.

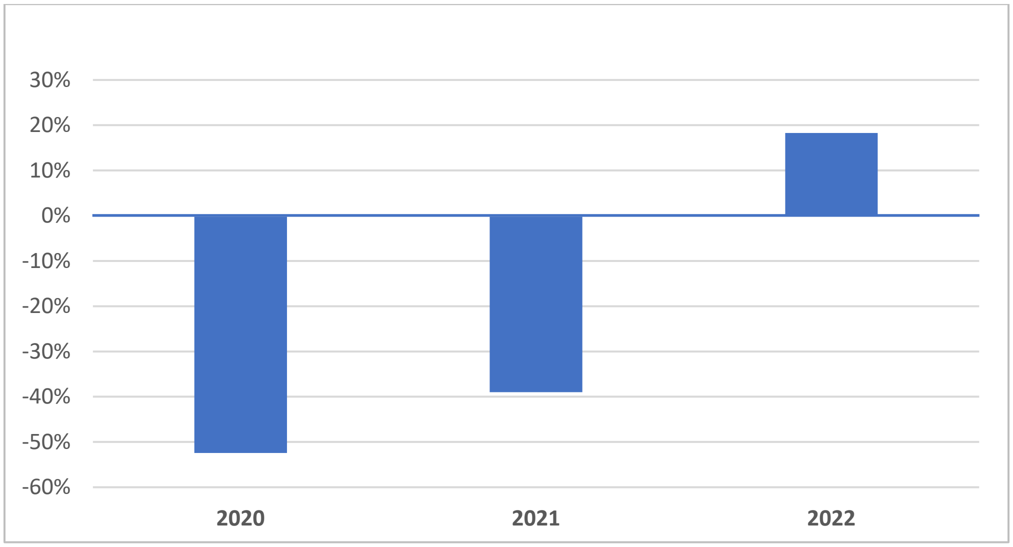
[18] The midstream companies whose expenditures were factored into estimating average Capex growth were Antero Midstream, Summit Midstream, Williams, MPLX, Energy Transfer, and Kinder Morgan.

[19] *See* https://www.spglobal.com/_assets/documents/ratings/research/101074077.pdf

[20] As determined from Ohio EPA permit data.

[21] The Mountaineer NGL storage project in Monroe County received a new set of environmental permits in late 2021 and will likely move forward if the PTT Global ethane cracker in Belmont County also moves forward (*see* https://marcellusdrilling.com/2021/10/oh-issues-permits-to-build-salt-caverns-for-mountaineer-ngl-h2-storage). MPLX is also still targeting the development of NGL storage caverns at its Hopedale complex (*see* https://www.cantonchamber.org/utica/presentations/jason-stechschulte.pdf).

Figure 8. Average Capex Growth for Midstream Operators



D. Downstream Development

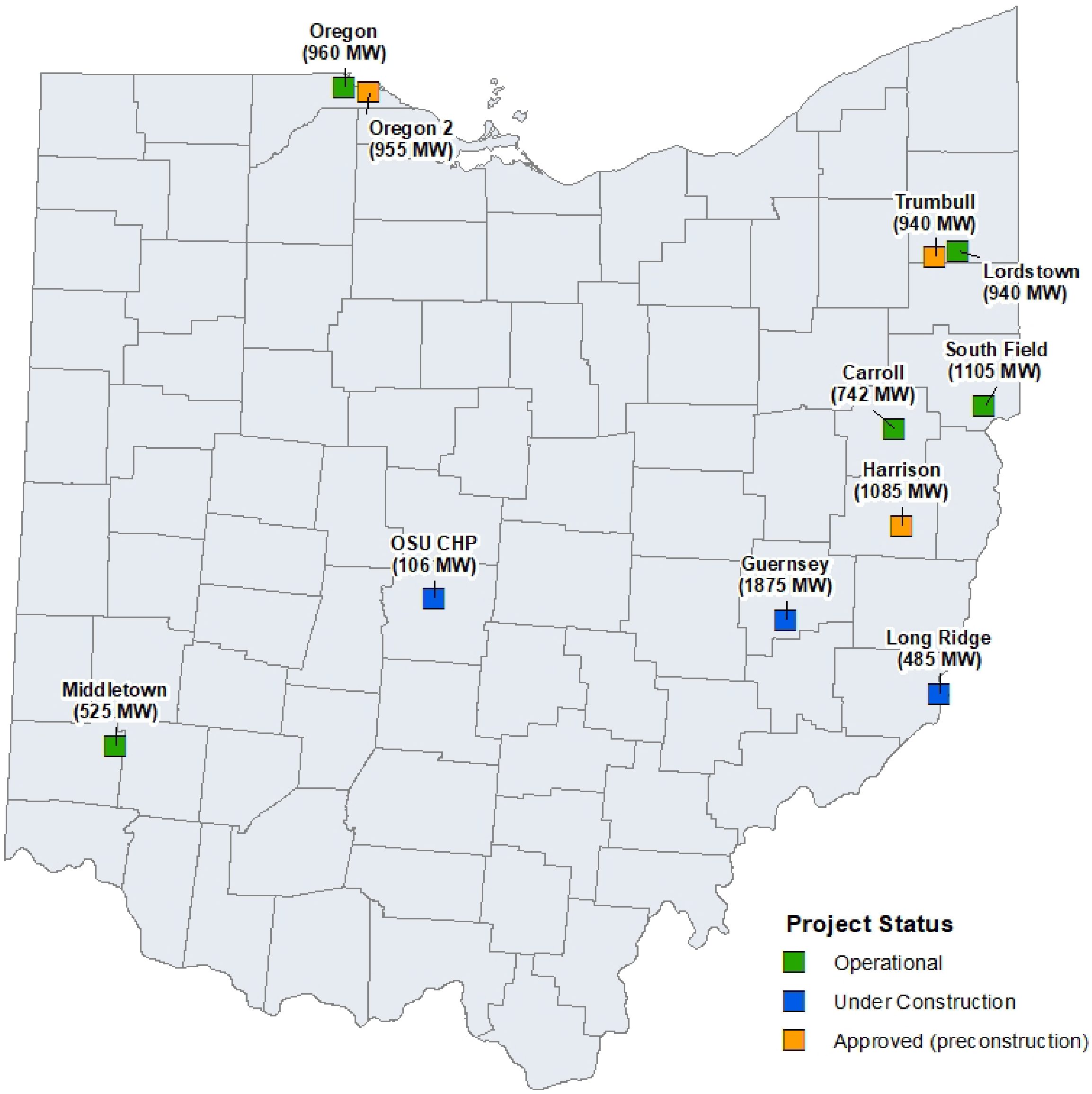
1. Combined Heat and Natural Gas Power Plants

Over the past ten 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. There were no new construction starts for these plants during the first half of 2021. The South Field Energy project—investment into which was included in a previous report—concluded construction and began commercial operations in October 2021.[22] Construction on the $1 billion Harrison Power Plant had not started as of April 2022. A recent agreement between plant operators and the Harrison County Commissioners is targeting a July 2022 groundbreaking.[23] This investment will be included in a future shale report.

COVID-related supply chain issues delayed construction on the 105.5 MW CHP plant at Ohio State University's main campus.[24] Major equipment installation on the $289.9 million project was completed in the second half of 2021 and will be included in the next shale report.[25] The 10 current and projected natural gas-powered facilities across 8 locations, along with the CHP project at Ohio State, including their current status, are set forth in Figure 9 below.

[22] https://www.southfieldenergy.com/news/south-field-energy-begins-commercial-operation/
[23] https://www.wtrf.com/harrison-county/commissioners-extend-zone-agreement-with-harrison-power-plant/
[24] https://www.google.com/search?client=firefox-b-1-d&q=ohio+state+chp+105.5
[25] *See* https://trustees.osu.edu/sites/default/files/documents/2021/11 /MPF_Public_Session_Materials_Nov21.pdf

Figure 9. Existing and Projected Natural Gas Power Plants



Source: Ohio Power Siting Board (2021)

2. Other Downstream Investment

Construction on a $6.3 million compressed natural gas (CNG) refueling station at the Greater Cleveland Regional Transit Authority's Triskett Garage began in April 2021.[26] Similarly, the Central Ohio Transit Authority (COTA) opened a second CNG refueling station at its Fields Avenue facility in January 2021 to serve its growing fleet of CNG buses.[27] COTA's new stations added $25 million in natural gas-based refueling investment for the study period.[28]

Marathon's Canton oil refinery saw upgrades during the study period that expanded its processing capacity by 3,000 barrels per day.[29] This facility processes oil production from Utica shale into products such as gasoline and asphalt.[30] According to the EIA, the unit capital investment for expanding capacity at a facility such as the Canton refinery that produces both distillates and higher-values products such as gasoline is $5,280/bbl/day.[31] The Canton refinery's overall processing capacity expansion in the first half of 2020 was therefore estimated at $15.84 million.

As of spring 2022, PTTGC America is still looking for a partner to invest in the multi-billion-dollar Belmont County cracker plant.[32] To date, it has invested more than $300 million in the project.[33] Included in this investment total is $538,000 in real estate purchases by PTT during the first half of 2021.[34] The company commented recently that it is still "hopeful that this project can become a reality."[35] The March 2022 renewal of the project's Ohio EPA air permit corroborates this sentiment.[36]

Altogether, $47.7 million in downstream investment was attributed to the first half of 2021. Cumulative downstream investments reported to date in Ohio, including 2011 through the first half of 2020, are set forth in Table 18 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.

[26] http://www.riderta.com/sites/default/files/events/2021-07-13TriskettCNG.pdf
[27] *See* https://afdc.energy.gov/
[28] *See* https://www.bizjournals.com/columbus/news/2018/06/27/cota-plans-to-add-electric-buses-to-fleet-as-it.html
[29] *See* Marathon Petroleum's FY2021 and FY2020 Form 10-K submissions to the U.S. Securities and Exchange Commission: https://d18rn0p25nwr6d.cloudfront.net/CIK-0001510295/dae2337b-f7be-4089-8cef-7acb12708a9c.pdf; https://d18rn0p25nwr6d.cloudfront.net/CIK-0001510295/2e568e5d-2387-443e-860e-557a13fa2b27.pdf
[30] *Id.*
[31] https://www.eia.gov/analysis/studies/petroleum/lto/pdf/lightightoil.pdf
[32] https://www.wtrf.com/belmont-county/is-the-cracker-plant-still-coming-to-belmont-county/
[33] *Id.*
[34] *See* https://realestate.belmontcountyauditor.org/Search/Name
[35] https://www.wtrf.com/belmont-county/is-the-cracker-plant-still-coming-to-belmont-county/
[36] *See* https://www.reutersevents.com/downstream/engineering-and-construction/thailands-ptt-global-chemical-announcement-new-application-permit

3. CONCLUSION

Total upstream shale investment in Ohio was up considerably in the first half of 2021 compared to the second half of 2020, driven entirely by rising natural gas and oil prices and their subsequent upward effect on royalties. (Average regional residue gas and oil prices were up 220% and 62%, respectively, in the first half of 2021 compared to the second half of 2020.) While southerly Belmont County again led all counties in production, more northerly Jefferson County for the second time in a row had the highest number of new wells developed during the Study period. This suggests that drilling activities continue to be focused more northward. Indeed, 70% of new well development occurred in northern counties during the first half of 2021. Altogether, upstream shale investment totaled more than $2.2 billion for the first half of 2021.

Midstream investments were down substantially in the first half of 2021 compared to the second half of 2020 as COVID-related effects continued to ripple through the natural gas industry. Among the investments that did occur during the Study period were $43 million in gathering system buildout, including $29 million for pipelines and $14 million for compression. The Study period was likely the low point for Utica midstream investment as actual spending for this segment in the second half of 2021, along with capital expenditure budgets for 2022, indicate a moderate upward trend.

Without any natural gas power plants breaking ground, downstream investments remained muted during the first half of 2021, consisting primarily of the development of two transit-based CNG refueling stations totaling a combined $31.1 million. Oil refinery capacity expansion added another $15.8 million. While no final investment decision was made on the ethane cracker in Belmont Company during the Study period, PTTGC America did continue buying real estate in support of the project, adding more than half a million dollars to its portfolio during the first half of 2021.

Altogether, shale-related investment in Ohio for the first half of 2021, including upstream, midstream, and downstream, was around $2.3 Billion. Cumulative total shale related investment since 2012 is around $95.3 billion.

About the Study Team

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About the Energy Policy Center

The Energy Policy Center is housed within the Maxine Goodman Levin College 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 10: Total Utica Production in Bcfe (Gas Equivalence) by County through June 2021

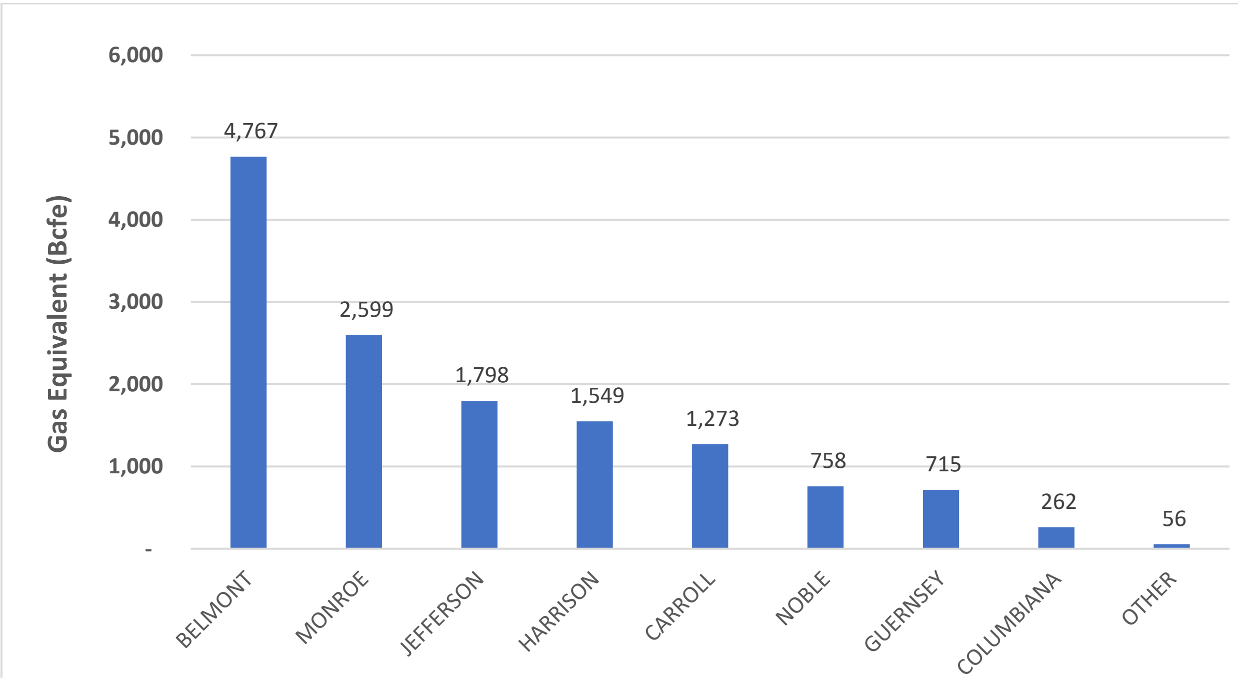


Figure 11: Total Utica Production in Bcfe by Operator through June 2021

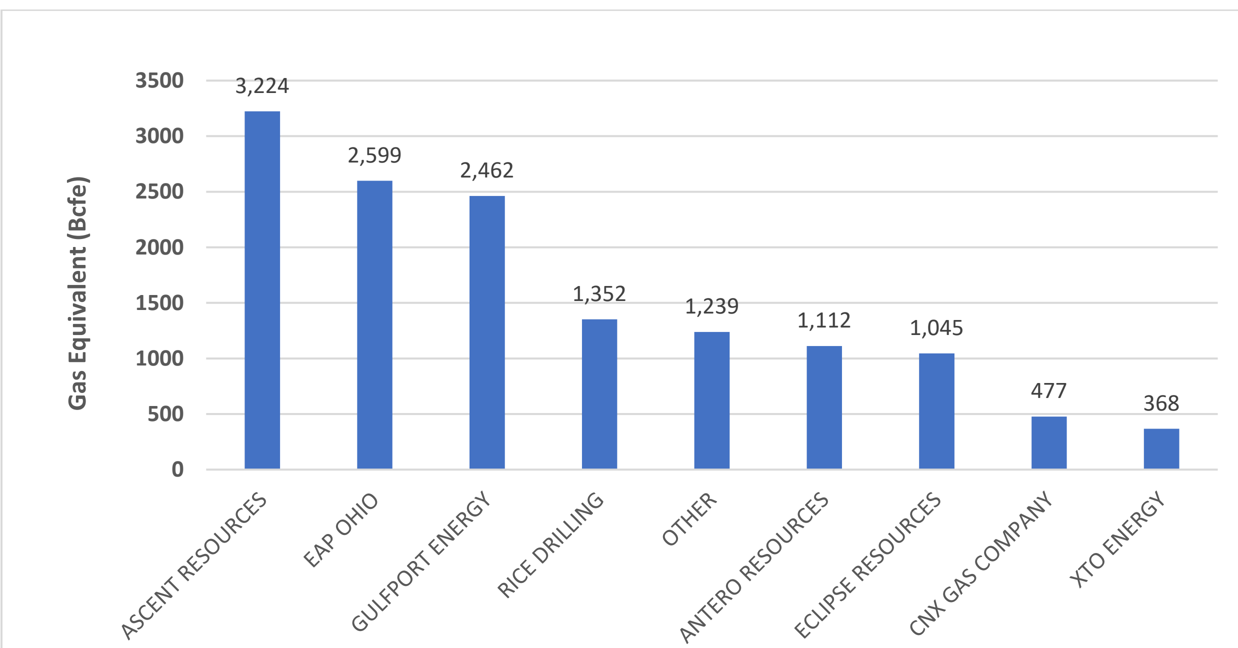
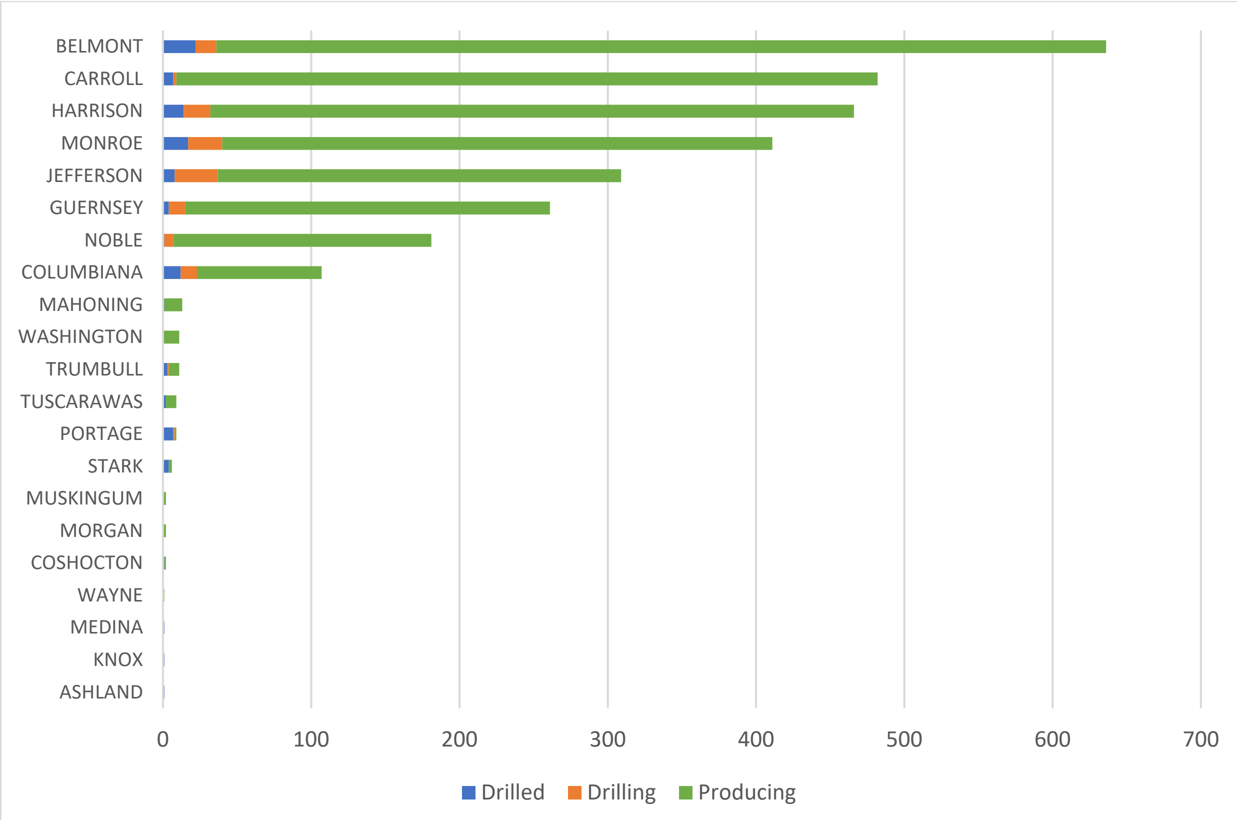


Figure 12: Cumulative Number of Wells by County through June 2021



Source: Ohio Department of Natural Resources (June 2021)

Figure 13: Distribution of Gas Equivalent Production for 2011 through June 2021

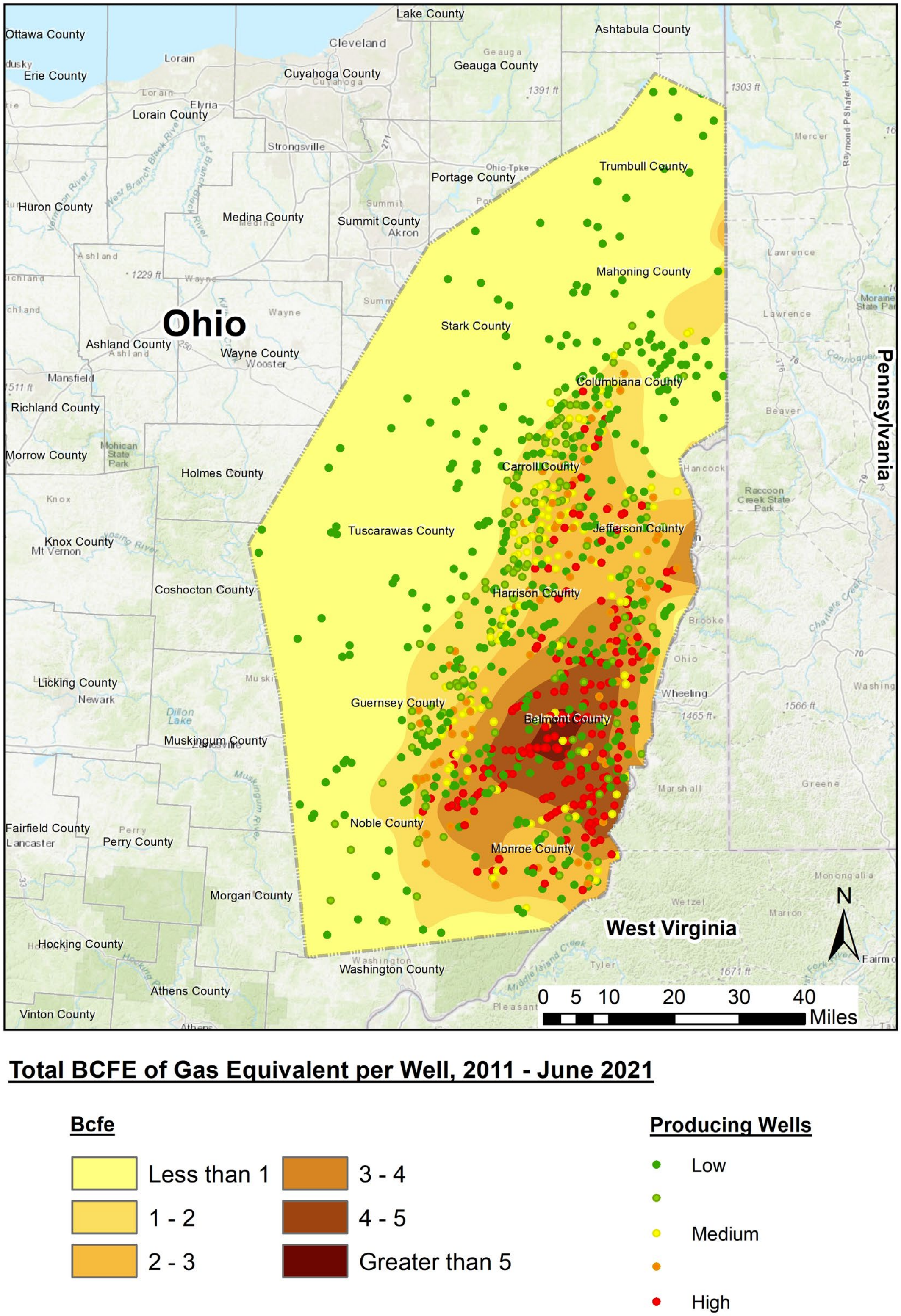
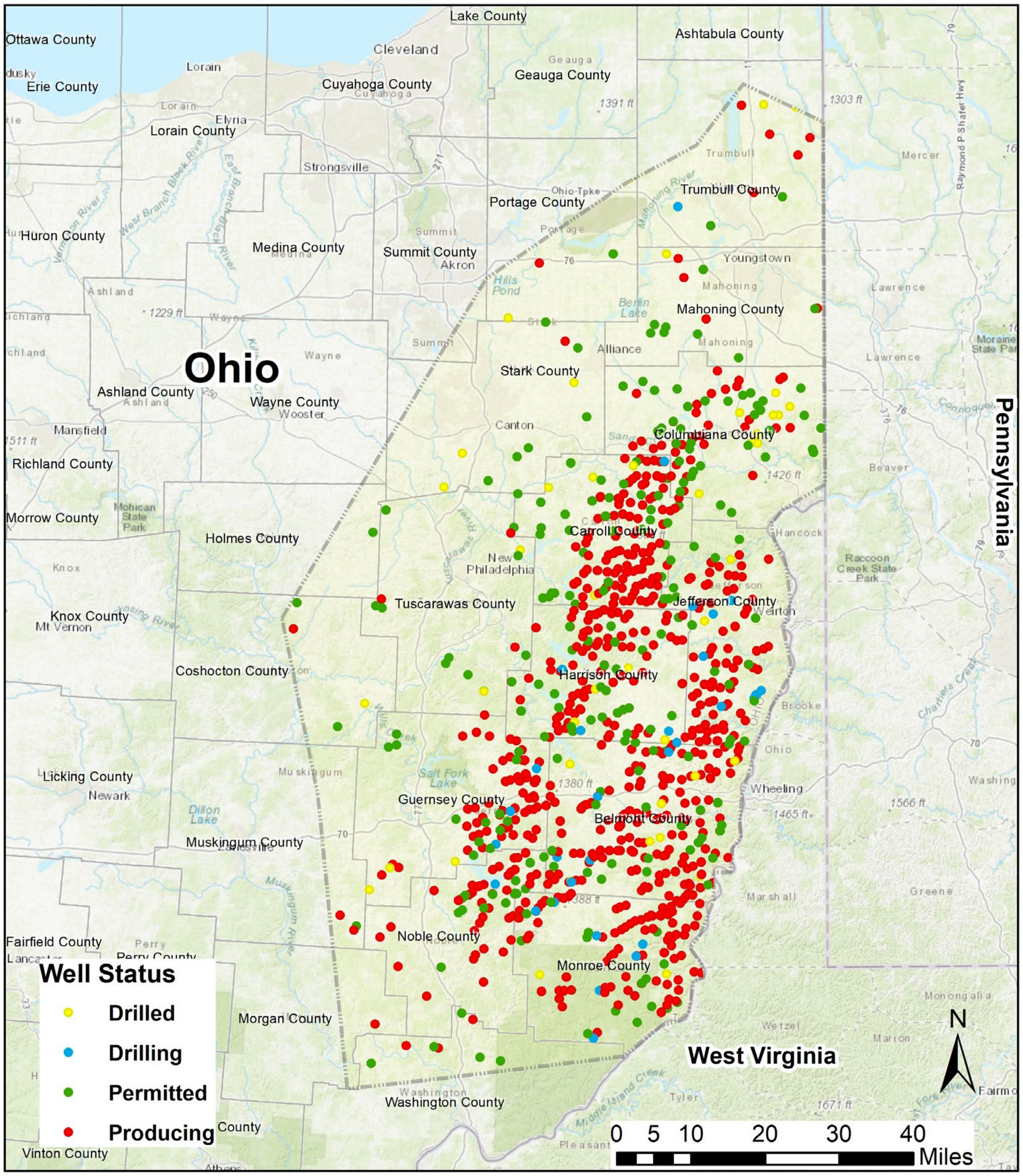


Figure 14: Distribution of Utica Wells by Status as of June 2021



Source: ODNR (2021)

Table 14. Utica Upstream Companies Drilling in Ohio as of June 2021

Operator	Cumulative no. of Wells
EAP OHIO LLC	887
ASCENT RESOURCES UTICA LLC	667
GULFPORT APPALACHIA LLC	419
ANTERO RESOURCES CORPORATION	238
ECLIPSE RESOURCES I LP	196
RICE DRILLING D LLC	149
XTO ENERGY INC.	58
CNX GAS COMPANY LLC	46
EQUINOR USA ONSHORE PROPERTIES INC.	42
PENNENERGY RESOURCES LLC	40
HILCORP ENERGY COMPANY	34
UTICA RESOURCE OPERATING LLC	34
DIVERSIFIED PRODUCTION LLC	25
PIN OAK ENERGY PARTNERS LLC	24
GEOPETRO LLC	17
GULFPORT ENERGY CORPORATION	12
ARTEX ENERGY GROUP LLC	9
NORTHWOOD ENERGY CORP	6
SUMMIT PETROLEUM INC	6
CHESAPEAKE EXPLORATION LLC	3
DEVON ENERGY PRODUCTION CO LP	3
BRAMMER ENGINEERING INC	2
EQT PRODUCTION COMPANY	2
AMERICAN ENERGY UTICA LLC	1
BP AMERICA PRODUCTION COMPANY	1
TRIAD HUNTER LLC	1
Grand Total	**2,923**

Note: Cumulative Number of Wells are calculated based upon the total number Drilled, Drilling, and Producing. Source: ODNR (June 30, 2021).

Table 15: Total Lease Operating Expenses through June 2021 (in millions)

Year	Period	Production Wells	Lease Operating Expenses for Period ($mm)
2021	Q1 and Q2	2,700	205.7
2020	Q3 and Q4	2,705	206.1
2020	Q1 and Q2	2772	266.2
2019	Q3 and Q4	2497	262.2
2019	Q1 and Q2	2173	228.0
2018	Q3 and Q4	2200	231.0
2018	Q1 and Q2	1874	191.2
2017	Q3 and Q4	1818	121.8
2017	Q1 and Q2	1588	141.3
2016	Q3 and Q4	1467	101.2
2016	Q1 and Q2	1355	97.6
2015	Annual	1034	148.9
2014	Annual	612	88.1
2013	Annual	237	34.1
2012	Annual	82	3.0
2011	Annual	9	0.3
		Total	**2,326.70**

Table 16: Cumulative Utica-Related Upstream Investments in Ohio through June 2021

Estimated Investments	Total Amount
Mineral Rights	$25,536,570,000
Drilling	$28,350,600,000
Roads	$1,092,460,000
Lease Operating Expenses	$2,326,752,000
Royalties	$8,637,261,000
Total	**$65,943,643,000**

Table 17: Cumulative Utica-Related Midstream Investments in Ohio through June 2021

Estimated Investments	Total Amount
Midstream Gathering	$7,702,187,000
Processing Plants	$1,259,300,000
Fractionation Plants	$1,697,360,000
NGL Storage	$261,000,000
Rail Loading Terminals	$145,000,000
Transmission Pipelines	$10,303,128,000
Total	**$21,367,975,000**

Table 18. Cumulative Utica-Related Downstream Investments in Ohio through June 2021

Estimated Investments	Total Amount
Petrochemical Plants and Refineries	$635,263,000
Other Industrial Plants	$760,000,000
Natural Gas Refueling Stations	$78,675,000
Natural Gas Power Plants	$6,442,500,000
Combined Heat and Power (CHP) Plants	$87,470,000
Total	**$8,003,908,000**

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: Northern Counties - $11.4 mm/well; Southern Counties - $12.9 mm/well.[37]
  - Equivalent true vertical depth (TVD) for wells in all counties.
  - Average drilling and completion costs of $900 per lateral foot.[38]
  - Average lateral length of 12,660 ft. for northern counties and 14,360 ft. for southern counties.[39]
- Roads: average investments - approximately $60,000 per well based on 2013 data from Carroll County Engineer's Office.[40]

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 July 1, 2020, from the number existent as of December 31, 2020. This information was downloaded from the ODNR Oil and Gas Well database.[41]

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 around $12,700/month, throughout the life of the well. This average expense was developed by the study team based on analysis of Ascent's lease operating expenses for the second half of 2020, divided by the number of wells operated, as reported in their financial statements.[42]

[37] 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 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. However, the same review of drilling surveys indicated that laterals for new wells in southern counties were 1,700 feet longer on average than for those in the north. This difference in average lateral length is the basis for the difference in drilling cost between northern and southern counties.

[38] Based on Ascent Resources' estimated drilling costs per lateral foot in the Utica according to the company's chairman and CEO. Ascent is active in both northern and southern counties. *See* https://oklahoman.com/article/5626621/ascent-resources-reports-growth-in-utica-shale-field-during-2018

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

[40] *See fn 12, supra.*

[41] http://oilandgas.ohiodnr.gov/well-information/oil-gas-well-database

[42] *See* https://ascentresources.com/documents/18/2019_Consolidated_Financial_Statements__Ascent_Resources_Utica_Holdings_LLC.pdf. *See also* https://ir.gulfportenergy.com/all-sec-filings/content/0001628280-20-002453/0001628280-20-002453.pdf

For purposes of estimating the lease operating expenses for Q1 and Q2 of 2021, the Study Team assumed that all wells listed as "producing" by the Ohio Department of Natural Resources on July 1, 2020 were incurring this cost and continued to do so through December 31, 2020.

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. [43]
- The residue energy content was around 1.1 MMBtu/Mcf.[44]
- Residue gas in the Utica was selling at an average price of $4.62/MMBtu for Q1 and $2.69/MMBtu for Q2.[45] This price for the Columbia-Appalachia hub was used to estimate royalties.
- Around 44 barrels of liquids were recovered per million cubic feet of gas produced.[46]
- Natural gas liquids were selling for around 30% of the listed price for Marcellus-Utica light crude oil.[47]
- Oil in the Utica region was selling for $47.91 and $56.14 per barrel, on average, during the first and second quarters of 2021, respectively.[48]
- Royalty rates are 20% of gross production.

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

[43] Based on industry interviews, experts citing API 12.3, Manual of Petroleum Measurements and Standards
[44] The EIA estimates that the average conversion should be 1.037 MMBtu/Mcf (*see:* www.eia.gov/tools/faqs /faq.php?id=45*)*. However, industry interviews suggest 1.1 is closer to the average conversion for the Utica Shale.
[45] https://www.naturalgasintel.com/cabot-southwestern-see-natural-gas-prices-impacted-by-appalachian-pipeline-constraints. 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
[46] Based on industry data.
[47] Based on industry interviews.
[48] *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

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.[49] 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 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 $3,876 for the Midwest Region as obtained from the INGAA, as projected for 2021.[50]

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

[49] 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.
[50] https://www.ingaa.org/File.aspx?id=34658

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[51]
- 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.[52]

For this report, up-to-date cost projections for natural gas transmission and gathering line pipelines, per inch-mile, was obtained from the Interstate Natural Gas Association of America (INGAA).[53] The estimated cost for natural gas pipelines for the Midwest Region as used in this analysis was $194,429 per inch-mile, which included labor, raw materials, and permitting costs, as projected by the INGAA for 2020.

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

[51] 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).

[52] that the data currently used supersedes data used in previous reports for study periods through June 30, 2017. Newer data suggests that the previously used assumption of 4 miles of gathering line per well pad was about twice as high as what midstream companies actually deploy in the field on average. Additionally, oil and gas companies can accommodate more than three times the 3-wells-per-pad that the Study Team assumed in prior studies. Earlier iterations of this dashboard assumed companies would drill three wells per pad on average, move on to other locations, and then come back later to infill. As the Utica play becomes more mature, we can expect that there will be a greater number of wells per pad, and therefore fewer gathering pipeline miles per well.

[53] The INGAA Foundation, Inc. (2018). *North America Midstream Infrastructure through* 2035. https://www.ingaa.org/File.aspx?id=34703.

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 12 shows the primary intermediates and products that can be manufactured from the main hydrocarbon components in shale gas as part of downstream production.[54]

[54] *See* https://www.energy.gov/sites/prod/files/2020/06/f76/Appalachian%20Energy%20and%20Petrochemical%20Report_063020_v3.pdf

Figure 15. Shale/Natural Gas Value Chain for Petrochemicals