Appalachian Natural Gas Liquids (NGLs) Resource Study

Final Report for Phase I (NGL Producer Engagement and Methodology Development)

Historical perspectives, terminology and assessment crosswalks, and recommendations for follow-on work

by

Douglas G. Patchen[1], Kristin M. Carter[2], Jessica P. Moore[3], Timothy W. Vance[3], James McDonald[4] and Katherine W. Schmid[2]

[1]West Virginia University Energy Institute; [2]Pennsylvania Geological Survey; [3]West Virginia Geological and Economic Survey; [4]Ohio Division of Geological Survey

Submitted by

West Virginia University Energy Institute

June 30, 2021

TABLE OF CONTENTS

LIST OF APPENDICES

LIST OF ACRONYMS

AONGRC	Appalachian Oil & Natural Gas Research Center
ASTH	Appalachian Storage & Trading Hub
AU	Assessment Unit
BTU	British Thermal Unit
DOE	U.S. Department of Energy
EI	Energy Institute
EIA	Energy Information Administration
EUR	Estimated Ultimate Recovery
EUR/mi^2	Estimated Ultimate Recovery per square mile
GBRU	Geneseo-Burket Reservoir Unit
GIP	Gas-in-Place
LTI	Leonardo Technologies, Inc
MRU	Marcellus Reservoir Unit
NETL	National Energy Technology Laboratory
NG	Natural Gas
NGLs	Natural Gas Liquids
NGPLs	Natural Gas Plant Liquids
NRCCE	National Research Center for Coal and Energy
OGIP	Original Gas-in-Place
PAGS	Pennsylvania Geological Survey

PGC	Potential Gas Committee
PUD	Proven but Undrilled
RE	Recovery Efficiency
RUs	Reservoir Units
SPE	Society of Petroleum Engineers
TRR	Technically Recoverable Resources
TPS	Total Petroleum System
USGS	United States Geological Survey
WVGES	West Virginia Geological & Economic Survey
WVU	West Virginia University

UNIT ABBREVIATIONS USED IN THIS REPORT

Bbbls	billion barrels
bbls	barrels
Bcf	billion cubic feet
Bcfge	billion cubic feet gas equivalent
Mcf	thousand cubic feet
MMbbls	million barrels
MMcf	million cubic feet
PSIA	pounds per square inch absolute
Tcf	trillion cubic feet

1.0 INTRODUCTION

The recent expansion of petrochemical projects nationwide, resulting in an increase in investments and jobs, coupled with the discovery and exploitation of rich (wet) gas in the Marcellus and Utica shale gas plays, led to the 2017 industry and Benedum Foundation-funded Appalachian Oil & Natural Gas Research Consortium's (AONGRC) geologic study that identified multiple sources for underground storage of natural gas liquids (NGLs) in a proposed Appalachian Storage and Trading Hub (ASTH). Two years later, with activity in these shale plays increasing and interest in NGLs and building cracker plants elevated, the U.S. Department of Energy (DOE) decided that a new assessment might be in order given the high degree of uncertainty evident among various assessments. Therefore, to determine if a full assessment had merit, DOE awarded a contract to West Virginia University (WVU) for a one-month pre-assessment study and WVU assigned the study to AONGRC, and more specifically to the state geological surveys in Ohio, Pennsylvania and West Virginia under the direction of the WVU Energy Institute's (EI) National Research Center for Coal and Energy (NRCCE).

The main goal of this pre-assessment study was to identify and document all assessments of natural gas and natural gas liquids published during the previous 25 years. Shortly after the report, "Development of an Updated Natural Gas Liquids Resource Assessment for the Appalachian Basin," (Carter and others, 2019) was submitted, the U.S. Geological Survey (USGS) released two fact sheets that updated their previous assessments of the Utica and Marcellus shale gas plays. As such, those assessments were not included in the AONGRC report.

In January 2021, the WVU Energy Institute received an award (Appalachian Natural Gas Liquids Resource Study) from DOE through Leonardo Technologies, Inc. (LTI) to conduct a six-month paper study to investigate the potential benefit of a new natural gas liquids resource assessment of the Utica and Marcellus shale plays in the Appalachian basin. The goal of this investigation was to prepare a background paper that:

- ✓ updates the literature review prepared by the EI in 2019 to include the new USGS reports and any other recent assessments and articulate a clear understanding of what is being assessed/estimated and how these data compare with their previous report;
- ✓ interprets the existing assessments according to user needs, methodology, vintage of assessment, data used and level of detail and provides the "best" current estimates from the existing literature and explains the rationale; and
- ✓ provides a clear explanation as to how the Energy Information Agency (EIA)'s resource terminology (i.e., proved reserves, economically recoverable, technically recoverable and remaining-in-place) and Potential Gas Committee (PGC)'s resource estimate terminology (i.e., proved reserves, Probable, Possible and Speculative Resources) map to one another.

2.0 THE 2019 REPORT – "Development of an Updated Natural Gas Liquids Resource Assessment for the Appalachian Basin"

Goals specified by DOE in the 2019 award included: (1) compile and characterize the type, amount and vintage of NGL resource data that were currently available for the Marcellus and Utica plays; (2) evaluate the results of this compilation to develop opinions regarding the need, value and timing of an updated NGL assessment; and (3) provide a written report to DOE detailing the results and recommendations regarding the effort.

Due to the limited time available to the research team, AONGRC conducted a concurrent four-prong approach to meet DOE's stated goals: (1) search and compile assessments in the pre-2016 literature; (2) search and compile assessments in the literature from 2016 to the present (2019); (3) form an opinion of how existing assessments would be changed by employing more current data sets; and 4) form an opinion of the benefit of developing an updated NGL resource assessment.

2.1 The Pre-2016 Task

The goal of the pre-2016 task was to "describe the quantity, quality and vintage of NGL data utilized in commonly-cited studies and analyses that were published in the two decades prior to 2016" (i.e., 1995-2015).

The research team completed a compilation and review of 14 reports that represented: assessments of NGLs with oil and gas; assessments of gas that included NGLs and oil; forecasts of NGL demand with assumed supply to match; and production summaries. However, very few assessments of NGLs or oil or gas were found to have been conducted and published in this time period.

True resource assessments published in this 20-year period were those by USGS and AONGRC. The USGS published an assessment of the entire Appalachian basin in 1995, and separate assessments of the Marcellus (2002; 2011) and Utica (2012). It is important to note that the assessment of NGLs increased dramatically with time and more data: from 15 million barrels (MMbbls) for the entire basin in 1995; to 11.4 MMbbls for the Marcellus alone in 2002; to 3,379 MMbbls for the Marcellus in 2011. Their initial assessment for the Utica in 2015 assigned 208 MMbbls to this play.

AONGRC (Patchen and Carter, 2015) assessed the oil and gas in the Utica Shale in AONGRC's play book that separated the play into three trends – oil, wet gas and dry gas. Although NGLs were not addressed specifically, the assessed volume of wet gas, 56,427 billion cubic feet (Bcf) could be used in conjunction with the gallons of NGL/Mcf extracted at gas processing plants to arrive at an assessment of NGLs in the wet gas trend.

2.2 The 2016-Present (i.e., early 2019) Task

The goal of this second task was to "describe the quantity and quality of more recent NGLs data," (i.e., data that had become available since 2015). This search through the 3+ years of published reports resulted in the compilation of 24 reports, largely of production data for the two shale plays and forecasts of NGL demand, but not NGLs potential ultimate supply. In addition, articles were published by DOE, EIA and others in the private sector that focused on the infrastructure that will be required to retain and exploit the resource and the economic impact of this enhanced production by keeping the products in the region.

Thus, no true assessments of NGLs in either play could be found. However, the study concluded that the explosion in the sheer number of relevant reports strongly indicated an increased interest in NGLs in the basin.

One example of this increased interest is the 2016 PGC report (Martin, 2017). In this report, PGC attributed a mean increase of 214 Tcf (trillion cubic feet) in the region to an on-going evaluation of the shale plays, primarily the "world class natural gas resource" in the Marcellus Shale with a "sizeable storehouse of hydrocarbon liquids," and the "prolific new gas and liquids play" in the Utica Shale.

Although no NGL resource assessments were found in the literature, the expansion of drilling and production in the Marcellus and Utica plays during this timeframe provided a larger and more varied dataset for future assessments. Thus, the study concluded, "NGL assessments would no longer require the extrapolation of data from other shale plays, as the USGS did in their 2012 Utica assessment."

2.3 Final Conclusions and Recommendations in the 2019 Report

"The most important outcome of the Study is that a much more complete, true assessment of the NGL resource in the Marcellus and Utica shale plays can be prepared now using the data at hand."

"Caveats to performing this work include industry participation and the process of ethane rejection."

3.0 NEW ASSESSMENTS SINCE THE 2019 REPORT WAS COMPLETED

Our new (2021) search resulted in 12 reports and presentations that were separated into five categories: (1) assessments of undiscovered oil, gas and NGL resources in the Marcellus and Utica plays; (2) assessments of natural gas in both plays; (3) assessments of gas-in-place (GIP) and recovery efficiency (RE) for the Marcellus play; (4) reserve estimates; and (5) production summaries and other data.

3.1 Basinwide Assessments of Undiscovered and Unproven Gas and NGL Resources

3.1.1 U.S. Geological Survey (USGS)

USGS published separate Fact Sheets for undiscovered resources in the Point Pleasant-Utica (Enomoto et al, 2019) and Marcellus (Higley et al, 2019) gas plays. These USGS assessments are only for "undiscovered resources," a terminology that at first would suggest that they may not include "discovered but undrilled" resources comparable to PGC's category of Probable Resources. However, their methodology, subtracting drilled acreage from total acreage and assessing the remaining, undrilled acreage as an undiscovered resource would suggest otherwise. Thus, for USGS, the remaining supply of natural gas would be reserves in producing wells or wells drilled and completed capable of production, plus undiscovered (undrilled) resources. However, one could argue that this method would include proved but undrilled acreage adjacent to existing wells already included in reserves by industry and EIA.

USGS used a geology-based approach to assess the volume of undiscovered, technically recoverable resources in continuous accumulations in the Marcellus and Utica plays. This type of assessment method is based on the geologic parameters of a total petroleum system (TPS) that involves the character of source rock (composition, richness, level of maturity, gas generation and retention), reservoir rock (composition, brittleness, fractures, thickness, porosity, permeability) and types and distribution of reservoir traps and seals and their timing with respect to oil and gas generation.

Marcellus Shale Play

In the case of the Marcellus, the TPS is the Devonian Shale – Middle and Upper Devonian TPS, which the USGS assessment team divided into six assessment units (AUs): a Western Margin Marcellus Shale Gas AU; Northern Interior Marcellus Shale Gas AU; Southern Interior Marcellus Shale Gas AU; Southwest Interior Marcellus Gas AU; Eastern Interior Marcellus Shale Gas AU; and Foldbelt Marcellus Gas AU.

The USGS team determined and used six geologic parameters to differentiate among these six AUs: potential productive acres; average drainage area per well; success ratios; untested acres available; average Estimated Ultimate Recovery (EUR); and AU probability of success. The estimated total undiscovered mean resources in the six AUs are 96,479 Bcf of natural gas and 1527 MMbbls of NGLs. Compared to a previous assessment of the Marcellus play (Coleman and others, 2011), these volumes represent an increase of 12,281 Bcf (14.6%) of natural gas and a decrease of 1852 MMbbls (54.8%) of NGLs.

The decrease in the assessment volumes of NGLs can be explained by the more detailed approach used in 2019 to define six assessment units versus only three in the 2011 assessment. The external AUs – the Western Margin and Foldbelt Marcellus AUs – remained the same but the large Interior AU of the 2011 assessment – which contained 96.6% of the natural gas and 96.3% of the NGLs – was divided into four AUs in the 2019 assessment, with varying values for available acreage, success rates and EURs.

The available (undrilled) acreage determined by USGS in the four interior AUs is 9.5 million acres. Two of the four (Southwest Interior AU and South AU) contain 88% of the assessed NGLs but only 44% of the total interior acreage. The other 56% of the acreage was divided nearly evenly between the Northern Interior AU with zero assessed NGLs and the Eastern Interior AU with only 12% (90 MM of 1,527 MMbbls) of the total NGLs. However, in the 2011 assessment, the entire 9.5 million acres was treated as having equal potential for NGL resources.

Milici and others (2014) offered suggestions as to why the 2011 assessment of the Marcellus gas play was so much greater (84.2 Tcf vs. 1.9 Tcf) than the 2002 assessment (Milici and others, 2003), mainly because the 2002 assessment was completed prior to the use of horizontal drilling and hydraulic fracture technology to develop the large continuous gas accumulation in the Marcellus. Milici noted that the 2002 assessment used production data from vertical wells in a smaller part of the basin. Subsequent development using new technology resulted in higher volume wells and a larger play area.

Much the same can be said for the interval between the 2011 and 2019 assessments. Continued development with horizontal wells and hydraulic fracturing resulted in the discovery of two "hot spots," one in southwestern Pennsylvania and one in north central Pennsylvania. The southwestern Pennsylvania hotspot is in the Southern Interior AU with the second largest NGL accumulation in the 2019 assessment. The north central hotspot is in the Northern Interior AU with no assessed NGLs. In the 2011 assessment, both areas were in the same AU and were given the same parameters, resulting in a higher assessment. This demonstrates again that with continued time and drilling resulting in more and better data, assessments can be significantly improved.

Utica Shale Play

In addition to the 2019 assessment of the Marcellus gas play, USGS (Enomoto and others, 2019) also completed an updated assessment of the undiscovered oil, gas and NGLs in the Utica Shale and Point Pleasant Formation in Ohio, Pennsylvania and West Virginia. These two shales are the primary source rocks in the Utica-Lower Paleozoic TPS of Milici and others (2003). Two AUs were defined and assessed separately, a Point Pleasant-Utica Shale Oil AU in Ohio and northwest Pennsylvania, and a Point Pleasant-Utica Shale Gas AU, mainly in Pennsylvania and West Virginia although the AU does extend into New York where there is no activity. Key input data for both AUs include potential productive acreage, average drainage area per well (acres), untested area (in %), success ratio and average EUR (MMbbls oil, Bcf gas).

The assessment increased the volume of undiscovered resources to 1819 MMbbls of oil; 117,211 Bcf of gas and 985 MMbbls of NGLs. In contrast, the 2012 assessment (Kirschbaum and others, 2012), with the same AUs, concluded that the undiscovered technically recoverable resources in the black shale facies of the thermally mature Utica Shale contained an estimated mean 940 MMbbls of oil, 38.2 Tcf of gas and 208 MMbbls of NGLs. Thus, the 2019 assessment raised these volumes by 93.5% for oil, 206.8% for gas, and 373.6% for NGLs.

The 2012 assessment assigned a much higher NGL resource volume to the Gas AU (199 MMbbls) than to the Oil AU (only 9 MMbbls). However, in the 2019 assessment the USGS team determined that the Oil AU contained 438 MMbbls of technically recoverable NGLs and the Gas AU contained 547 MMbbls.

The 2019 assessment team had the advantage of seven more years of drilling activity, thus more data from the play, whereas the 2011 assessment team had to rely on limited Utica production data supplemented by analog data from other shale plays, including the Marcellus, and on EUR distributions from other shale gas AUs.

3.1.2 Energy Information Administration (EIA)

EIA publishes annual reports on oil, condensate and gas reserves in which they include data on natural gas plant liquid (NGPL) reserves. A summary of information on reserves in the 2020 Annual Energy Outlook (AEO) report (EIA, 2021a) is presented below in Section 3.4.

EIA provided additional information in their “Assumptions to the Annual Energy Outlook for 2021” (EIA, 2021b), especially their assessment of “remaining technically recoverable resources” (TRR), defined as proved reserves plus unproven resources. “Unproven resources” are defined as “undiscovered resources that are located outside oil and gas fields where the presence of resources has been confirmed by exploratory drilling” that can be produced “using current recovery technology but without reference to economic profitability” (EIA, 2021b). Unproven resources in EIA terminology also include resources in undiscovered pools within confirmed fields, a definition that would equate to part of the PGC definition of Probable Resources (i.e., new pools that have been discovered but unconfirmed by drilling).

For continuous shale plays like the Marcellus and Utica, TRR is the product of area with potential (square miles), well spacing (wells per square mile) and EUR per well. The natural gas resource in the east, an area estimated by EIA to contain 888.4 Tcf of TRR, is dominated by the Marcellus (318.9 Tcf) and Utica (274.2 Tcf). EIA further breaks down the TRR by the three areas in the Marcellus play identified by USGS in their 2011 assessment: Foldbelt (0.2 Tcf); Interior (315.8 Tcf); and Western (2.9 Tcf). The Utica is divided into four areas: gas zone core (208.1 Tcf); gas zone extension (5.1 Tcf); oil zone core (1.9 Tcf); and oil zone extension (0.1 Tcf).

In this same report (EIA, 2021b), EIA also reported their updated assessment of NGPLs using gas-to-liquids ratios and the purity splits of the NGPL barrels that were updated starting with their AEO 2017 report. For the Marcellus play, the total TRR for NGPL is 15.9 Bbbls, mostly in the Marcellus Interior (15.7 Bbbls). For the Utica, the total resource is estimated by EIA to be 6.5 Bbbls, mainly in the gas zone core (3.9 Bbbls) and gas zone extension (2.5 Bbbls) areas.

3.2 Assessments of Natural Gas

PGC assesses the volume of natural gas that can be recovered with current technology and economic conditions. Their assessment includes both discovered and undiscovered resources whereas the USGS assessment only includes undiscovered resources. The PGC further divides the natural gas resource into Probable (discovered, but unconfirmed by drilling), Possible (undiscovered) and Speculative (other geologic provinces) categories. The PGC only assessed

Probable and Possible gas resources for the Utica and Marcellus gas plays and did not assess NGLs for either play.

PGC does not divulge resource numbers for individual plays. However, in the year-end 2018 report (Martin, 2019) PGC noted that the assessment in the Atlantic Area (essentially the Appalachian basin) included a "growing component reflecting rising liquids and gas production from the Utica Shale in Ohio" and "all of the 263, 650 BCF (mean value) increase in the Atlantic Area's assessment for 2018 arose from ongoing evaluation of Appalachian basin shales, predominantly the prolific Marcellus."

The report also stated that "the vast Marcellus Shale in the Northern Appalachians represents a world-class natural gas resource as well as a sizeable storehouse of hydrocarbon liquids, and the Utica Shale has become a prolific gas and liquids play." The 19.5% increase in resource for the entire area was attributed to a reevaluation of numbers for Appalachian basin shales which collectively account for 96% of the Atlantic Area's total onshore Traditional resource assessment (Most Likely value).

Although actual volumes for these plays cannot be released, we can look at percentage increases or decreases from the 2016 to 2018-year end assessments. In the Marcellus play, the TRR assessed by the PGC Appalachian team of experts decreased 3.2% from 2016 to 2018. The volume of Probable Resource increased but the volume of Possible Resource decreased as new drilling moved areas in the play from Possible to Probable. This was a reversal of the trend from 2014 to 2016 in which the total recoverable resource in the Marcellus increased 17.8%, led by a 33.6% increase in Probable Resource.

In the Utica play, the total resource volume increased by 4.9%, led by a 35.6% increase in the Probable Resource volume. Increases were assessed in both the rich and lean gas areas (Most Likely values). The 2018 assessment benefited from a doubling in the number of Utica wells added to the database, which led to a much smaller increase in resource volumes from 2016 to 2018 than for the increase from 2014 to 2016 (82.5%). The increase from 2014 to 2016 was due largely to a 104.5% increase in Possible Resources as the footprint of the play expanded.

The year-end 2020 PGC assessment (Blood, 2021) will be released in late summer 2021. However, an advance working copy of the report revealed no significant increase in assessed volumes for either the Marcellus or Utica plays.

3.3 Estimates of Gas-in-Place (GIP) and Recovery Efficiency (RE)

Boswell and others (2019, 2020) took advantage of a large dataset for production and forecast data that made it possible to map EUR for gas wells in the West Virginia portion of the Marcellus play. They used two independent estimates for 166 developments (single operator, common spacing) including 900+ wells and compared them to published GIP maps to produce maps of ultimate expected RE, defined as "the percentage of gas recovery with respect to the total gas-in-place (GIP) with respect to a specific reservoir rock volume." They concluded that

"EUR/mi^2 often exceeds the GIP previously assigned to the Marcellus." They also concluded that recovery in the Marcellus is greater than previously assumed and that actual GIP estimates are greater than previously assessed.

By comparing their map of EUR/mi^2 to published estimates of both TRR and original GIP resources they show that Marcellus wells "appear capable of producing significantly more gas than previously estimated" (Boswell and others, 2020). Their evaluation revealed that TRR in the Marcellus play in West Virginia is "typically greater than 50 bcf/mi^2 throughout the basin center and less than 30 bcf/mi^2 along the pay margin," in linear trends that parallel the north-northeast axis of the basin. Using a new estimate for GIP for select wells, their revised estimates of RE indicate that Marcellus wells in the basin center are capable, throughout a 50-year life, of producing 20-60% of the GIP. They also state that REs for wells on the play margin are lower.

Although the authors do not deal directly with NGLs, they do state that in the northwestern part of West Virginia heavier gases are "increasingly common in the reservoir," ranging from 0 to greater than 50% from east to west (Boswell and others, 2020; figure 11). Because they report these liquids as being produced at the wellhead in billion cubic feet of gas equivalent (Bcfge) we can assume the liquid is condensate, not NGLs which would be removed from the wet gas stream at a processing plant.

More recently, Boswell (2021, personal communication) updated figure 1 from his Society of Petroleum Engineers (SPE) paper (Boswell and others, 2020), a review of assessments over time, to include new estimates of the remaining TRR for the Marcellus and the Utica basinwide. These new "best estimates" are 690 Tcf for the Utica and 695 Tcf for the Marcellus, plus 15% or minus 30% to deal with uncertainty in the EURs. This uncertainty would create a range of 480 to 785 Tcf for the Utica and 485 to 800 Tcf for the Marcellus.

Pool and others (2021) updated the study of RE and EUR in the Marcellus Shale in West Virginia. They used the "reservoir units" (RUs) approach from Boswell and others (2020) and defined the Marcellus Reservoir Unit (MRU) as the Marcellus and overlying rocks extending 300 feet (ft) upwards or to the base of the Tully Limestone. They also defined a separate Geneseo-Burket Reservoir Unit (GBRU) above the Tully.

Their analysis resulted in an Original Gas-in-Place (OGIP) of 878 Tcf for the Marcellus RU and 115 Tcf for the Geneseo-Burket RU, and further divided the RU estimates stratigraphically, assigning 532 Tcf to the Marcellus Shale and 125 Tcf to the overlying Mahantango Formation. Throughout most of West Virginia these two RUs would have a combined OGIP exceeding 40 Bcf/mi^2 and greater than 150 Bcf/mi^2 in north central West Virginia. The authors estimated that the Marcellus alone had OGIP greater than 80 Bcf/mi^2 in the core area of the play.

The RE for further development of the Marcellus play was estimated to range from 20 to 60% and equal or exceed 50% in the core area.

The authors attribute their higher estimates of OGIP and RE to improved data volume and quantity; exclusion of non-representative vertical and older horizontal wells; their calibration of in place estimates compared to observed and predicted well performance; and to the vertical extension of productive units creating thicker RUs.

They determined that the TRR in the Marcellus in the study area was 232 Tcf, of which 28 Tcf had been produced or was in reserve to be produced, leaving 204 Tcf as a future TRR.

3.4 Reserve Estimates

EIA issued a new report on oil and gas reserves (EIA, 2021a) that included NGPLs and some information specific to the Marcellus and Utica plays. Gas reserves in the U.S. declined 2% in 2019 relative to year-end 2018, due mainly to a price decline that led to a downward revision in reserves, which are price sensitive. EIA noted that this was the first downward revision in natural gas reserves since 2015.

Shale natural gas reserves increased from 67.8% of the total U.S. reserves in 2018 to 71.3% in 2019. The largest net gain in shale gas reserves (10.4 Tcf) was in Ohio due to the Utica play; the second largest net gain (2.4 Tcf) was in Pennsylvania due to continued development of the Marcellus play.

Pennsylvania continued to rank first among states in proved shale gas reserves (105.4 Tcf; up 2006 Bcf)) with Ohio 3rd (34.4 Tcf; up 10,420 Bcf)) and West Virginia 4th (34.0 Tcf; up 2272 Bcf). Pennsylvania saw a shale gas reserve increase of 13,666 Bcf due to field extensions and new discoveries reported by industry. West Virginia operators reported adding 7642 Bcf to Marcellus gas reserves through extensions and new discoveries in the Marcellus. Ohio operators added 1677 Bcf in new reserves in the Utica play due to extensions and discoveries.

The estimated volume of NGPLs contained in the nation's proved gas reserves decreased slightly (0.9%) from 21.8 Bbbls to 21.7 Bbbls. In the Appalachian basin, the estimated yield of natural gas plant liquids from proved natural gas reserves is estimated by EIA to be 2484 MMbbls in West Virginia, 1008 MMbbls in Pennsylvania, and 487 MMbbls in Ohio.

EIA's annual natural gas proved reserves are incorporated into PGC's biennial reporting (see Section 3.2) in that current EIA proved reserve volumes are added to PGC natural gas volumes to estimate the future supply of natural gas in the United States. In this manner, the routine reporting of natural gas proved reserves by EIA is complementary to the natural gas assessment work prepared by the PGC. There is, however, an important caveat to the estimated future supply of natural gas volume data as reported by PGC. EIA prepares proved reserve volumes annually but does not release its annual data for a given year until late the following year. PGC prepares biennial natural gas assessment reports, but these are not published until about six to nine months after the end of the two-year reporting period. Because of differences in report timing, PGC must use the proved reserve data reported by EIA in the year preceding the close of the biennial reporting period to tabulate the estimated future supply of natural gas for (e.g., the 2019 EIA reserve data are being used in the 2018-2020 biennial PGC report to estimate the future natural gas supply volume at the close of year 2020).

3.5 Production Summaries and Other Data

New information in this category consisted of reports by state geological surveys, presentations at technical meetings, and information posted online by producers for their stakeholders.

3.5.1 West Virginia Geological and Economic Survey (WVGES)

WVGES continued their annual reporting of Marcellus Shale and Utica-Point Pleasant drilling and production (Dinterman, 2020). Data for 2019 in the report were as reported by industry to the West Virginia Environmental Protection Office of Oil & Gas as of July 31, 2020 and may not include production from several operators involved in the two shale plays.

The reporting requirements changed in West Virginia effective January 2018. Current reporting requires that downstream NGLs "accounted to a well" must be reported as NGL produced from that well whereas wellhead lease condensate must be reported as crude oil. Prior to that change, condensate data were reported separately, but NGL data were not reported.

The number of horizontal Marcellus wells for which production was reported increased to 2758, up 302 from 2018. Production from these horizontal wells was 1891.2 Bcf. Vertical wells (1424, up 14 from 2018) added 3.8 Bcf to the production total (1895.1 Bcf; up 289.6 Bcf from 2018). This volume of gas from the Marcellus represented 87.9% of all gas reported as being produced in 2019, a decrease from 2018 (90.6%).

NGLs also were produced from the Marcellus, but due to the reporting changes noted above comparison of data from year to year is not consistent. The NGL total in 2019 was 61,175,252 bbls; the 2018 total was 64,233,908 bbls.

Total gas production from 48 wells in the Utica-Point Pleasant play area of West Virginia was 77.4 Bcf, an increase of 54.9 Bcf from 2018. In addition, 46,190 bbls of oil were reported as being produced from five wells, and 162,433 bbls of NGLs were reported from three wells.

3.5.2 Pennsylvania Geological Survey

In Pennsylvania, operators are required to report production from unconventional wells (i.e., shale wells) within 45 days after the end of each month. The products that must be reported are natural gas (Mcf), condensate (barrels) and oil (barrels). Pennsylvania has defined each of these products as follows:

- Gas – a fluid, combustible or noncombustible, which is produced in a natural state from the earth and maintains a gaseous or rarified state at standard temperature of 60 degrees Fahrenheit and pressure of 14.7 PSIA. This product type must be reported in MCF (1000 cubic feet) at a standard temperature of 60 degrees Fahrenheit and pressure of 14.7 PSIA.

- Condensate – a low density, high API gravity, mixture of hydrocarbons that is present in a gaseous state at formation temperatures and pressures but condenses out of the raw gas to a liquid form at standard temperature of 60 degrees Fahrenheit and pressure 14.7 PSIA. This product type must be reported in barrels. Do not report any non-hydrocarbon liquids as condensate.
- Oil – hydrocarbons in liquid form at formation temperatures and pressures that remain in liquid form at standard temperature of 60 degrees Fahrenheit and pressure 14.7 PSIA. This product type must be reported in barrels.

PAGS processes completion reports and reviews monthly production reporting for Marcellus Shale and Utica-Point Pleasant wells on a regular basis. The following paragraphs summarize Marcellus and Utica production data for calendar years 2019 and 2020. Production volumes for natural gas, condensate and oil have been rounded to the nearest 10 Bcf and 10 bbls, respectively.

The number of Marcellus wells for which production was reported was 7221 in 2019 and 7219 in 2020 (essentially flat). Gas production from these wells was 3680 Bcf in 2019 and 3230 Bcf in 2020. Condensate production from these wells was 1,834,680 bbls in 2019 and 1,577,690 bbls in 2020. Oil production was reported at 1540 bbls in 2019 and 730 bbls in 2020.

The number of Utica wells for which production was reported was 186 in 2019 and 191 in 2020 (a slight increase). Gas production from these wells was 115 Bcf in 2019 and 80 Bcf in 2020. Condensate production from these wells was 10 bbls in 2019 and 0 bbls in 2020. Oil production was reported at 49,820 bbls in 2019 and 57,740 bbls in 2020. PAGS is aware that the increase in oil production from Utica wells in 2020 seems counterintuitive, and we have reached out to the Department of Environmental Protection, which maintains the online portal operators use to self-report production data. As of the date of this report, we have no resolution on this matter.

3.5.3 Other

Information in this category includes presentations at (virtual) technical meetings and slides or text posted on company websites. Two examples follow.

DOE has expressed that one of their main concerns is with the volume of ethane that is rejected, i.e., left in the marketed gas stream to be combusted when it could be extracted and sold to be used in the manufacturing sector to produce durable products like plastic in its many uses. This is a valid concern, as illustrated below in the data from Antero Resources.

Antero posted data on their rich (1250 British Thermal Units [BTU]) gas production in a company presentation (Antero, 2021, slide 7). Seventy percent (70%) of the NGLs are rejected, remaining in the gas stream, some of which is necessary to meet pipeline requirements (1100 BTU maximum). The remaining 30% (165,000 bbls/day) is removed from the gas stream at processing plants. Of this 165,000 bbls/day total, 115,000 bbls/day is C_3 plus heavier liquids and the remaining 50,000 bbls are C_2 (ethane).

Heavier liquids in the 115,000 bbls/day production are broken down as: 56% propane; 17% normal butane; 10% isobutane; and 17% pentanes plus. Antero's daily production can be calculated as 550,000 bbls/day (30%, or 165,000 removed in processing plants, 70%, or 385,000 bbls rejected). Of this total, total ethane would be 435,000 bbls (385,000 rejected, 50,000 removed); propane would be 64,400 bbls; normal butane 19,550 bbls; isobutane 15,500 bbls; and pentanes+ 19,550 bbls.

Dave Boyer, Mudrock Energy, gave a presentation at the Appalachian Upstream 2020 meeting on April 22, 2021 that included data on drilling in shale plays in Pennsylvania, Ohio and West Virginia during 2020. Seventy six percent (76%) of new wells spudded in the Marcellus Shale (437 wells) were in Pennsylvania; the other 24% (137 wells) were spudded in West Virginia. For the Utica play, 79% of new wells (136) were drilled in Ohio, 14% (24 wells) were drilled in Pennsylvania and 7% (12 wells) were drilled in West Virginia. Marcellus "hot spots" continued to be northeast Pennsylvania, southwestern Pennsylvania and Tyler County, West Virginia. Drilling to the Utica Shale was concentrated in the tri-state region in southeast Ohio, Cameron County, Pennsylvania and the northern panhandle of West Virginia.

4.0 "BEST" ESTIMATES OF NGL RESOURCES

As described in the statement of work for this project, a "best" estimate of resources and reserves is dependent on the needs of the end user, i.e., the need for updated assessments on current reserves, recoverable resources, total remaining gas supply, or OGIP.

A best estimate or assessment also could be defined as the latest estimate or assessment. Boswell (2021b) has noted and graphically depicted not only the disparity in resource estimates made by different workers, but also the gradual increase in volume over time. Various factors can lead to this increase, including more drilling to define total play area and differentiate among assessment units, longer production histories, more efficient well spacing and completion techniques and new approaches in making assessments. Boswell (2021b) also suggested that earlier assessments were often quite conservative due to the limited data available with which to assess a large play area. He mapped the difference in play area assessed by various workers to demonstrate one reason for the variation in assessments.

Since July 2019, new resource assessments of the Marcellus and Utica plays have been released by USGS, EIA, PGC, Boswell and others, and Pool and others. However, of these, only USGS included assessments of NGLs, although EIA provided estimates of NGPL resources that could be produced from technically recoverable natural gas resources (TRR). The assessments by Boswell and others (2020) and Pool and others (2021) of natural gas resources are considerably higher than those of the federal agencies but do not include NGLs. PGC made assessments of natural gas resources in the Marcellus and Utica but does not release assessments of individual gas plays. So, as far as the best assessment of NGL in the two shale plays of interest, the only assessments that are available, as well as the latest and therefore the “best,” are those made by USGS (Enomoto and others, 2019; Higley and others, 2019).

4.1 USGS

USGS assesses undiscovered oil, gas and NGL resources using a geology-based approach; separates the play into smaller AUs for improved detail; gathers data on acreage, well number and acres/well to arrive at undeveloped drillable acreage in each AU and applies an average EUR to that number. Their most recent assessment of the Marcellus play broke down the large Marcellus Interior AU as defined in their 2011 assessment into four smaller AUs, resulting in an improved level of assessment, so their assessment volumes varied for each AU and for each commodity, including NGLs. However, USGS assessments are often quite conservative when compared to other recent assessments, and they applied much lower EURs per well than other assessment teams. Therefore, although theirs are the only assessments of NGLs in the Marcellus and Utica plays we can expect their final volumes of undiscovered resources (985 MMbbls in the Utica; 1527 MMbbls in the Marcellus) are conservative.

4.2 EIA

EIA assesses reserves of oil, gas and NGPLs as well as TRR, using a methodology similar to the USGS and in some cases separating a play into smaller areas determined by USGS in their assessments (for example, the three Marcellus areas defined in the USGS 2011 assessment; Utica sweet and non-sweet oil and gas areas). Like USGS, EIA uses play acreage, the number of wells, drainage area/well, available area, wells to be drilled on available acreage and EURs/well in each area of the play to determine TRR. They rely on data from industry for the EURs they use and upgrade the EURs every two years following an evaluation of current production histories and decline curves. Although they do not specifically assess NGLs in the reservoir they do make estimates of how many barrels of NGL could be extracted in the future if these unproven resource volumes are sent to a gas processing plant. Those volumes, 15.9 Bbbls in the Marcellus and 6.5 Bbbls in the Utica, are much lower than the volumes of undiscovered NGL resources assigned by USGS for these plays, although the volumes of undiscovered natural gas resource assessed by EIA were much higher (318.9 Tcf Marcellus; 274.2 Tcf Utica) than assessments by USGS (96.5 Tcf Marcellus; 117.2 Tcf Utica).

4.3 PGC

The PGC Appalachian work group assesses the natural gas resource on a routine basis (every two years), but does not assess oil or NGLs resources, nor does it assess reserves. They divide a play into smaller geographic areas, not based on geology like the USGS, but on proximity to established production and risk. Areas in close proximity to discovered resources but not yet drilled are assigned to Probable Resources with a higher expectation of future success (lowest risk). Areas farther away from proven production, thus undiscovered and undrilled, are assigned to Possible Resources (higher risk). Furthermore, in each of these areas the PGC team of experts for the Appalachian basin provides additional resource values for the Minimum, Most Likely and Maximum cases. Like the USGS and EIA, acreage, the number of wells, drainage area per well, available acreage and confidential EURs provided by industry are critical to the assessment. PGC does not release individual play volumes or non-aggregated datasets. The reason for this is to maintain strong working relationships with operators who provide open, honest, confidential insights to inform the PGC's biennial assessments. These relationships are integral to providing technically sound, economically reliable biennial gas assessments.

4.4 Boswell and Pool

Boswell and others (2020) and Pool and others (2021) took an entirely different approach prior to their actual assessment due to their observation that many horizontal Marcellus wells in West Virginia have out-performed expectations based on initial EURs and GIP. Using a large database of production for Marcellus wells they calculated new estimates of GIP and RE before calculating EURs/mi^2 as a technical recoverable resource, or TRR. They divided the Marcellus play area into smaller segments than USGS and EIA, using the average EUR expected to be achieved in a county or sub-county. Thus, their level of detail was greater than the two federal agencies, and comparable to the PGC approach. Like PGC, they did not deal with oil nor NGLs, only natural gas. Their assessments of TRR for both plays are the most optimistic of all assessments, 690 Tcf for the Utica (range of 480 to 785 Tcf) and 685 Tcf for the Marcellus (range of 485 to 800 Tcf). Given their approach and vintage, these assessments of natural gas are given the most credibility as more realistic (and optimistic). Therefore, if factors for NGLs extracted per MMcf of gas were applied to the assessments of this team of investigators they would be the highest available.

4.5 Summary

For assessments of NGL resources there are only two sources: USGS and EIA. Although they use similar methodology to make assessments of oil and natural gas, and their latest assessments are of the same vintage, they use a different approach to assess NGL resources, and USGS approach results in a higher volume.

For assessments of natural gas resources, there are four sources, essentially of the same vintage: USGS, EIA, PGC, and Boswell and Pool. However, PGC does not release assessment volumes by play. The assessments of both federal agencies are conservative when compared to the assessments of Boswell, Pool and PGC. The main reason for this is that the two federal agencies applied lower EURs/well than the other research teams. The Boswell and Pool teams provide evidence to support their use of higher EURs.

If the end user is interested in updated estimates of reserves of NGL and natural gas, the only source is EIA.

5.0 HOW TO IMPROVE THE "BEST" ASSESSMENTS

The final task of our effort to define how to improve assessments of Marcellus- and Utica-based NGL resources in the Appalachian basin is to recommend how the "best" assessments could be improved in a subsequent phase (Phase III) of this project, that is, the development of a full NGL resource assessment.

5.1 Assessments by Product Type

5.1.1 Natural Gas Liquids Resource

The only current assessments specific to NGLs for the Marcellus and Utica are those from USGS (Higley and others, 2019; Enomoto and others, 2019). These 2019 assessments resulted in NGL resource volumes of 1527 MMbbls for the Marcellus and 985 MMbbls for the Utica. When compared to previous assessments of the Marcellus (Coleman and others, 2011) and Utica (Kirschbaum and others, 2012) these volumes represent a decrease of 1857 MMbbls for the Marcellus but an increase of 777 MMbbls for the Utica.

In these most recent assessments, the USGS teams continued to use a geologic approach to assess oil, natural gas and NGL in the Utica and Marcellus. Geologic factors were used to separate the Marcellus into six AUs and the Utica into four AUs. Engineering data, including EURs/well, were accessed to assess the NGL volume in each AU.

A strength of the 2019 assessments was the availability of more and better data since 2011 and 2012 due to increased drilling, longer production histories and more accurate EURs. A second strength of the 2019 assessment of the Marcellus as compared to the 2011 assessment was the separation of the large Marcellus Interior Gas AU into four smaller AUs in which different engineering values could be applied for a more accurate overall assessment. Another strength was that the assessments were conducted by experienced assessment teams familiar with each play.

However, according to Boswell (2021), the EURs used by these teams are too low, resulting in a calculated TRR/mi^2 for natural gas that is much lower than his estimate and that by Blood and others (2020), and even lower than assessments by EIA (2021) and the University of Texas Bureau of Economic Geology (UT BEG; Ikonnikova and others, 2018). Some areas have produced more gas from the Marcellus than was assessed by USGS, and if the assessment of natural gas resource is conservative, then it follows that the assessed volume of NGLs will be conservative as well.

5.1.2 Natural Gas Plant Liquids Resource

An option to the "best" NGL resource assessment would be the assessment of NGPLs assessed by EIA (2021). EIA makes two assessments, one for NGPL reserves and one for NGPL resources. Both begin with an assessment of natural gas, one for reserves and one for unproven TRR, to which a factor determined from the volume of liquids extracted from each MMcf of gas at a gas processing plant is applied to achieve a NGPL resource volume. Although the natural gas resource volume assessed by EIA has increased with time (for example, for the Marcellus, an increase from 141 Tcf in 2012 to 319 Tcf in 2021) and thus the NGPL resource as well, Boswell (2021) has presented an alternate approach that strongly suggests that these NGPL volumes are too conservative.

5.1.3 Natural Gas Resource

In his evaluation of the natural gas resource in these two shale plays, Boswell (2021) concluded that there continues to be a large disparity in the volumes cited in the most recent assessments, especially those made by federal agencies (i.e., USGS and EIA) and has determined that this is due to many factors, including differences in the size of the play area defined in the assessment; a difference is the definition of technically recoverable resources; vintage and volume of data used; and determination of estimated ultimate recovery per cell size.

Boswell (2021) cites a spread in natural gas unproven technically recoverable resources (rTRR) for the Marcellus from 97 to 560 Tcf, approximately 500%, and a ~750% spread in assessment values for the Utica.

However, Boswell (2021) states that although both plays (Marcellus and Utica) now have large numbers of drilled and completed wells, very few of these wells have produced for more than eight years and those that have are earlier wells in the play that were completed with different and less effective practices. Thus, the results of even the most recent assessments remain "estimates with significant uncertainty," due mainly to the method used to apply EUR values from various sources to individual wells.

As stated above, a "best" assessment of NGLs begins with a "best" assessment of natural gas resources. In addition to USGS, three other entities have prepared natural gas resource assessments within the past several years, as summarized below.

EIA (2011) assigned 410 Tcf to the Marcellus, but later in the same year when the USGS released their assessment of only 84 Tcf, EIA lowered their number to 141 Tcf in 2012, before increasing it in both 2016 and 2018, and then to 319 Tcf in 2021. EIA assesses "unproven TRR" which is all technically recoverable natural gas associated with undrilled/unproven acreage.

PGC assesses technically recoverable natural gas resources separated into lower risk Probable Resources (proven but undrilled) and higher risk Possible Resources (unproven, undrilled). However, although PGC assesses individual gas plays, the volumes assessed for each play are not released to the public.

More recent assessments by Boswell and others (2020), Pool and others (2021) and Boswell (2021) are much more optimistic than the conservative volumes assessed by the two federal agencies. Boswell (2021) increased the assessed rTRR in the Marcellus to 693 Tcf and the rTRR in the Utica to 684.1 Tcf. These values for the remaining unproven TRR, when added to the developed TRR (cumulative production and reserves) increase the ultimate total of recoverable resources (uTRR) to 873 Tcf for the Marcellus and 725 Tcf for the Utica.

5.2 Suggested Improvements

We suggest five strategies for improving natural gas and related NGL resource assessments. The first three items serve to level-set expectations and understanding. The last two represent data compilation, review and analytical work to improve necessary inputs to the resource assessment.

1. <u>Clearly define what is being assessed</u>

Regardless of the terminology used, “undiscovered,” “unproven,” or “remaining unproven,” all assessments essentially evaluate the potential of undrilled acreage in a play to contain additional technically recoverable oil, gas or NGLs. Acreage held by production or reserves is subtracted from total play acreage to arrive at potential, undrilled acreage on which an assessment is made. In large, continuous accumulations like the Marcellus and Utica plays, different parts of the undrilled acreage have different potential for production. Assessment teams address this problem in different ways. USGS subdivides the larger area into smaller AUs and applies different parameters of potential and risk to each. PGC separates the play into areas of Probable or Possible potential and assigns different parameters to each. So, although different terms are applied, the assessments are similar in terms of what is being assessed, i.e., technically recoverable resources in undrilled areas.

However, although all assessment teams attempt to determine the resource potential of undrilled play acreage, they differ in their estimates of play size and the division of the play into smaller subareas. Boswell (2021, table 1) compared the play area (mi^2) assessed by EIA, USGS and UT BEG for the Marcellus in total and in each of the subareas (if subdivided). For the Marcellus play, EIA assessed the resource potential on 25,819 mi^2; USGS assessed the potential of 40,209 mi^2; and UT BEG assessed the resource on 39,400 mi^2.

For the Utica, the size of the total play area also differed among three assessments, from 15,565 mi^2 (WVGES) to 23,417 mi^2 (EIA) with USGS close to EIA at 20,586 mi^2.

USGS Assessments

USGS assesses “undiscovered,” technically recoverable resources, defined as volumes of oil, gas or NGLs in untested (undrilled) areas of the play. To add detail and improve the reliability of their assessment, USGS divides the larger play area into smaller assessment units defined by various geologic parameters. Undrilled but potentially productive acreage, well spacing and estimated ultimate recovery per well are used in the assessment.

Definitions of terms used by USGS:

> *Undiscovered resource* is the volume of gas to be produced on undrilled vs. drilled and thus proven acreage.
>
> *Gas supply* is the volume of undiscovered resources plus reserves.

Undrilled acreage may include some proven but undrilled (PUD) locations assigned to reserves, which could result in higher resource assessments (but the low EURs more than offset this, and the final resource numbers are quite conservative).

EIA Assessments

EIA assesses "remaining, unproven" technically recoverable resources, defined as the product of potential play acreage (mi^2), well spacing (wells/mi^2) and estimated ultimate recovery (EUR) per well.

Definitions of terms used by EIA:

Technically Recoverable Resource (TRR) is the gas resource that can be produced with current technology.

Unproven TRR is the gas resource yet to be discovered by drilling.

Reserves are the estimated volumes of natural gas determined by geologic and engineering analysis to be recoverable in the future from known reservoirs under current economic conditions and by using current technology.

PGC Assessments

PGC assessments are for "resources considered to be recoverable given adequate economic incentives and current technology." PGC does not assume that these volumes will be developed and produced, only that they could be with current and forseeable technology and economic incentives. PGC assesses both proven but undrilled resources and unproven resources, (further defined as Probable Resources and Possible Resources, respectively) and would not include undrilled acres in a developed area (included in reserves) to a resource area.

Definitions of terms used by PGC:

Discovered natural gas is historical production plus proved reserves in producing wells or undrilled infield wells (PUDs). Discovered gas also includes gas in fields that can be produced through the drilling of field extensions or new pools.

Undiscovered natural gas is the potential gas supply that can be produced following exploration discovery and field/pool development.

Cumulative Production is the volume of natural gas that has been produced from known fields and marketed for sale as well as gas used in field operations and otherwise delivered to an end user.

Proved Reserves are defined the same as the definition used by EIA, as the estimated volumes of natural gas determined by geologic and engineering analysis to be recoverable in the future from known reservoirs under current economic conditions and by using current technology.

Potential Resources include all categories of undiscovered gas resources plus that part of the discovered resource that has not been confirmed by drilling and testing and not included in reserves. Three categories are recognized and included in PGC assessments: Probable, Possible and Speculative, but the Speculative category is not applicable to our potential shale gas assessment.

Probable Resources are discovered but unconfirmed (undrilled) volumes that exist in known fields and are the most reliable of the three categories of resource assessment. Probable resources can exist in undrilled acreage associated with productive areas that will require field extension or new pool development.

Possible Resources are undiscovered volumes that exist outside of known fields and thus are assessed with a lower level of confidence. However, they are in a known productive formation in a producing province. Confidence in their assessment is favorable because a current play can be extended into the undrilled area.

Future gas supply is the sum of proved reserves and the three categories of potential resources.

Boswell and Pool Assessments

Boswell and Pool assess "remaining unproven" technically recoverable resources (TRR) but also distinguish among Ultimate TRR, Developed TRR, Remaining TRR and Future Supply.

Definitions of terms used by Boswell and Pool:

Total Gas in Place (TGIP) is all the gas in the ground, both recoverable and not technically recoverable at present.

Ultimate TRR (uTRR) is the volume of gas available for production during the life of a play. Various subdivisions exist.

Developed TRR (dTRR) includes all recoverable natural gas associated with drilled acreage, that is gas already produced and gas yet to be produced in existing wells and in adjacent but undrilled acreage.

Remaining, unproven TRR (rTRR) is all recoverable gas associated with unproven/undrilled acreage. rTRR is approximately equal to that assessed by the USGS and EIA.

Future supply (fsTRR) is all gas remaining to be produced, the total of reserves plus rTRR.

TRR Density (TRR/mi^2) is the volume of gas per cell size used in the assessment. Boswell and Pool developed this measure as a "useful means" of comparing productivity assumptions among various assessments.

2. <u>State what the resource results will represent</u>.

What the final assessed volumes represent is similar for all assessments: the remaining resource volume that is technically recoverable with current technology on undrilled but potential acreage in a play. But once the play area to assess is determined, we recommend that certain conditions need to be agreed upon to remove business, governmental and economic impacts/influence on play development and thus the resource numbers at the end of an assessment.

Thus, resource assessments should represent resources in the ground that can be recovered using today's technology and economic conditions. Whether or not the resource will eventually be produced is not a factor, nor is whether ethane will be extracted or rejected to remain in the gas stream, or whether commodity prices change during the assessed life of the play (50 years).

It also is necessary to begin the assessment of NGLs in a play with the best assessment of natural gas possible; the higher the assessed value of natural gas containing NGLs, the higher the value of NGLs in that assessment. How many barrels or gallons of NGLs are contained in an MMcf of natural gas in the reservoir is the question, and how to determine that ratio is the problem at hand.

At present, the primary method is to determine the gallons of NGLs extracted from each MMcf of natural gas throughput at a gas processing plant and then multiply that factor times the volume of natural gas assessed to be recoverable from the reservoir. Criticism of this method revolves around ethane rejection - how much ethane is left in the gas stream to increase the BTU content of the gas sold versus how much could be extracted and sold as ethane? This volume will change with time as the price of ethane and natural gas change, but this cannot be determined in advance over the long life of a play. The best we can do with this method is to use current practice.

Other options that could be employed in a new assessment are mapping BTU values at the wellhead across the play; mapping EURs/well across the play; and mapping NGL content, across the play. These mapping exercises are dependent on the cooperation of at least one large gas producer in each play.

3. <u>Recruit confidential industry support for critical input parameters (EUR, BTU, NGL volume/MMcf at the wellhead</u>).

To achieve or even attempt the mapping exercises described above, we would need to recruit operators in the two shale plays of interest that measure the BTUs at the wellhead. Collection of these wellhead data would allow mapping of BTU distribution across both plays; the higher the BTUs, the greater the volume of NGLs.

A second query for operators is EUR/well data, and how EUR/well data may vary across their acreage to better level-set expectations prior to launching into #4 below.

And finally, it would be to our advantage to obtain downstream data, the separation of NGLs per MMcf natural gas processed, and break the total NGL volume into various components like the example we noted above from Antero (2021). We would expect that as depth of the reservoir and thus maturity increases from west to east across both plays, the BTU content would decrease toward dry gas, the NGL volume would decrease, the percentage of "heavier ends" in the NGL volume would decrease and that of the lighter ends (ethane) would increase.

4. Reassess EUR values.

EUR/well data are one of the more important data values for a successful assessment, and there is a high level of uncertainty in the EURs used in various assessments to date. For example, Boswell (2021) has made a strong case for a reassessment of EURs applied in several of the more recent assessments. He attributed the difference in well-level EURs to the assumed decline rate used and compared decline rates in three independent sources of EURs to decline rates used by EIA and found the company data to be approximately 30% higher than that used by EIA.

As an example, Boswell (2021) determined that the average EUR/1000' of lateral in the Marcellus play is 1.63 Bcf and that for the Utica is 1.12 Bcf. But, when compared to the EURs used by USGS, these values are more optimistic than the conservative USGS values that ranged from 1.109 Bcf/well to 3.125 Bcf/well in the four AUs in the former Interior Marcellus Gas AU. If we use as an example the Southwest Interior AU, the EUR average per well applied by the USGS is 2.093 Bcf. Using their mean drainage area of 146.7 acres this would yield a lateral 8,520' long at a well spacing of 750' and dividing the EUR by this lateral length would yield a very low 0.246 Bcf/1000', much lower than the value determined by Boswell or experienced by operators in the play that typically are in the 1.0 to 2.0 Bcf/1000' range.

A reassessment of EUR values should include the following. First, use only representative wells, the more recent wells with longer laterals and more recent well spacing and eliminate older vertical wells and older horizontal wells with shorter laterals as suggested by Boswell (2021). Second, normalize EUR/well data into EUR/unit area using well spacing and lateral length and use an average of this value in a subarea to determine the resource in that subarea. And third, acknowledge and incorporate risk factors into the calculation, i.e., the possibility that wells drilled in the subarea will be as productive as the average for that subarea (Net/Gross%).

5. Scrutinize and refine the geospatial characteristics of both shale play areas.

A final area of agreement is on the total area of the Utica and Marcellus plays to be assessed, and the separation of the overall available potential acreage into smaller subareas based on historical activity, per well production and risk of new drilling matching current productivity.

As a second step, within the subareas of each play one should identify smaller focused areas in which more detailed assessment could be made based on differences in EURs in these smaller areas (perhaps even at the county-level).

For example, USGS has already subdivided the Marcellus play into six assessment units which could be retained, but within each AU we could take advantage of average EURs per well on a county basis and assess the resource county by county in a subarea and add the totals.

The Utica play area is quite large and has only been divided in the federal assessments into oil and gas areas with a sweet spot and outlying, non-sweet spots in each. However, WVGES added a subdivision for the wet gas trend between the oil and dry gas regions, again with a sweet spot and non-sweet spots, resulting in six subareas in the overall play. We suggest these six subareas be retained and smaller focused areas be identified in the large dry gas subarea based on activity and production potential demonstrated to date. This would allow us to place more weight on the more productive areas than on those areas that we anticipate being less productive.

5.3 Recommendations

We recommend either the PGC assessment or the Boswell and Pool assessment be accepted as currently the best assessment of the natural gas resource. From examining the assessments to date we see comparable results for either method. Both methodologies incorporate more granularity and mechanisms to account for varying degrees of productivity/risk in the assessment and show the variability in results that may be expected based on empirical data and operator insight (as opposed to employing a statistical method, as in the USGS and EIA approaches).

If the goal is to achieve a quicker assessment of NGLs, we recommend going forward that emphasis should be placed on mapping the regional distribution of NGLs in both liquid-rich gas plays, Marcellus and Utica, rather than beginning with another natural gas assessment. The greatest focus should be on the west side of both plays in and adjacent to the wet gas trends, with the dry gas region to the east being decreased in importance for the assessment of NGLs, especially the large Utica dry gas region. Subareas should be determined with distinctly different NGL/MMcf ratios that can then be applied to the natural gas resource assessed in those subareas, perhaps on a county-by-county basis. The cumulative total of NGL resource in the subareas will yield the final NGL assessed volume in each play.

We recommend all the improvements described above be employed with the selected resource approach.

6.0 SUMMARY

The 2019 one-month pre-assessment study employed multiple strategies to (a) identify and describe published NGL data for the Appalachian basin and (b) compile relevant information to formulate opinions regarding the potential benefit of revising Marcellus and Utica NGL assessments at the current time. The most important outcome of the study is that a much more complete, true assessment of the NGL resource of the Marcellus Shale and Utica Shale plays could be prepared using the data at hand

This updated six-month study located more recent (2019-2021) assessments, including two studies by the USGS that assessed NGLs as well as oil and natural gas in the Marcellus and Utica plays. However, according to Boswell, their natural gas assessments are too conservative due to the use of low EURs per well, so it follows that the NGL assessments are too conservative as well. However, an NGL assessment can be improved with a more detailed, focused approach utilizing more appropriate (higher) EURs based on cumulative production to date that in some areas has already surpassed the volumes assessed for that area. Wellhead data on cumulative production, BTUs and EURs on a well-by-well basis is critical for a new assessment. With the assistance and data input from Industry, a more positive, representative assessment of NGLs in the Utica and Marcellus can be made.

Caveats to performing this work include industry participation and the process of ethane rejection. It should be noted that the quality and usefulness of revised NGL resource assessments will depend on the infrastructure that has been created in the region over the past 10 years and whether industry operators will cooperate by sharing NGL and related data with AONGRC. The process of ethane rejection could probably be incorporated into the NGL assessments, although how much ethane must stay in the dry gas stream to meet pipeline requirements varies and would have to be estimated in some fashion before subtracting it from the overall resource.

7.0 REFERENCES CITED

Antero, 2021, Scotia Howard Weil 49th energy conference, March 2021, 47p.

Blood, R., McCallum, S., Jalali, J., Douds, A., Stypula, M., 2020, Toward a more accurate gas-in-place model: reconciling gas storage with gas production in the Marcellus Shale, Appalachian basin, USA; URTeC-2558, Austin, Texas

Blood, David (Randy), 2021, Potential supply of natural gas in the United States, report of the Potential Gas Committee, 2020; in preparation

Boswell, Ray, 2021a, personal communication

Boswell, Ray, 2021b, Evaluation of technically recoverable resources in the Marcellus and Utica shale gas plays of the Appalachian basin; National Energy Technology Laboratory, NETL-2021/3213, Pittsburgh, June 23, 2021

Boswell, R., Carney, B.J., and Pool, S., 2019, Constraining estimates of in-place gas resources and gas recovery efficiency via production data: an example from the Marcellus play of northern West Virginia; Presentation to the Appalachian Geological Society, November 12, Morgantown, WV

Boswell, Ray, Carney, B.J., and Pool, Susan, 2020, Using production data to constrain resource volumes and recovery efficiency in the Marcellus play of West Virginia; SPE-201752-MS, virtual presentation October 2020 at the SPE Annual Technical Conference & Exhibition, 20 p.

Carter, Kristin M., Patchen, Douglas G., Moore, Jessica P., Dunst, Brian J., Schmid, Kathern W., Dinterman, Philip and Daft, Gary W., Jr., 2019, Development of an updated natural gas resource assessment for the Appalachian basin; Appalachian Basin Oil & Gas Research Consortium report to the U.S. Department of Energy-Natural Energy Technology Laboratory, 16 p.

Coleman, J.L., Milici, R.C., Cook, T.A., Charpentier, R.R., Kirschbaum, M., Klett, T.R., Pollastro, R.M., and Schenk, C.J., 2011, Assessment of undiscovered oil and gas resources of the Devonian Marcellus Shale of the Appalachian Basin Province, 2011; U. S. Geological Survey Fact Sheet 2011-3092, 2 p.

Dinterman, Phillip A., 2020, 2019 Marcellus Shale and Utica-Point Pleasant production summary; West Virginia Geological & Economic Survey, 13 p.

Enomoto, C.B., Trippi, M.H., Higley, D.K., Drake, R.M., II, Gaswirth, S.B., Mercier, T.J., Brownfield, M.E., Leathers-Miller, H.M., Le, P.A., Marra, K.R., Tennyson, M.E., Woodall, C.A., and Schenk, C.J., 2019, Assessment of undiscovered continuous oil and gas resources in the Upper Ordovician Point Pleasant Formation and Utica Shale of the Appalachian Basin Province, 2019; U.S. Geological Survey Fact Sheet 2019-3044, 2 p., https://doi.org/10.3133/fs20193044.

Enversus, 2019, Precalculated, proprietary EUR database; Enversus White Paper, 10 p.

Higley, D.K., Enomoto, C.B., Leathers-Miller, H.M., Ellis, G.S., Mercier, T.J., Schenk, C.J., Trippi, M.H., Le, P.A., Brownfield, M.E., Woodall, C.A., Marra, K.R., and Tennyson, M.E., 2019, Assessment of undiscovered gas resources in the Middle Devonian Marcellus Shale of the Appalachian Basin Province, 2019; U.S. Geological Survey Fact Sheet 2019-3050, 2 p., https//doi.org/10.3133/fs20193050.

Ikonnikova, S., Smye, K., Browning, J., Dommisse, R., Gherabati, A., Gulen, G., Hamlin, S., Lemons, C., Male, F., McDaid, G., Medlock, K., Scanlon, B., Shuster, M., Tinker, S., Vankov, E., 2018, Final report on update and enhancement of shale gas outlooks; University of Texas BEG, 60 p.

Kirschbaum, M.A., Schenk, C.J., Cook, T.A., Ryder, R.T., Charpentier, R.R., Klett, T.R., Gaswirth, S.B., Tennyson, M.E., and Widden, K.J., 2012, Assessment of undiscovered oil and gas resources of the Ordovician Utica Shale of the Appalachian Basin Province, 2012; U.S. Geological Survey Fact Sheet 2012-3116, 6 p.

Martin, Linda, 2019, Potential supply of natural gas in the United States, report of the Potential Gas Committee; 106 p.

Milici, R.C., Ryder, R.T., Swezey, C.S., Charpentier, R.R., Cook, T.A., Crovelli, R.A., Klett, T.R., Pollastro, R.M., and Schenk, C.J., 2003, Assessment of undiscovered oil and gas resources of the Appalachian Basin Provence, 2002; U.S. Geological Survey Fact Sheet 009-03, 2 p.

Milici, Robert C., Coleman, James L., and Kirschbaum, Mark, A., 2014, Assessment of the Marcellus Shale, Utica Shale, and east coast Mesozoic basins in the eastern United States – a review; Search and Discovery Article #30336, posted June 9, 2014, 9 p.

Patchen, Douglas G. and Carter, Kristin A., editors, 2015, A geologic play book for Utica Shale Appalachian basin exploration; Utica Shale Appalachian Basin Consortium, 187 p.

Pool, S. E, Boswell, R.T., Saucer, J.T., Carney, B.J., 2021, Estimates of natural gas resources and production efficiency associated with Marcellus development in West Virginia; West Virginia Geological & Economic Survey, Reports of Investigation RI-36, 49 p., available Online http://www.wvgs.wvnet.edu/www/MUDvnnSh/MUDvnnSh.htm

U.S. Energy Information Administration (EIA), 2021a, Proved reserves of crude oil and natural gas in the United States, year-end 2019; www.eia.gov/naturalgas/crudeoilreserves/pdf/usreserves.pdf, 45 p.

U.S. Energy Information Administration (EIA), 2021b, Assumptions to the annual energy outlook 2021: oil and gas supply module; www.eia.gov/outlook/aeo/assumptions/pdf/oilgas.pdf, 22 p.

APPENDIX A

Similarities and Differences Between PGC and EIA Assessments

1.0 Summary

The Potential Gas Committee (PGC) produces a biennial report on the future natural gas supply in the United States (U.S.), both onshore and offshore. Their assessments are based on current technology and economics and include both discovered and non-discovered technically recoverable resources to which proved reserves are added to arrive at the future supply of natural gas in the U.S. The Energy Information Administration (EIA) provides estimates of proved reserves that are used by PGC; makes assessments of technically recoverable resources (TRR); and produces estimates of future natural gas demand. The material that follows regarding PGC can be found in PGC's 2018 biennial report (Martin, 2019). The summary of EIA reserve estimates can be examined in more detail on their website (https://www.eia.gov/naturalgas/crudeoilreserves/) and in their latest Annual Energy Outlook (EIA, 2021a). Detail on their assessments of TRR can be found in EIA's latest Assumptions to the Annual Energy Outlook (EIA, 2021b).

2.0 Introduction

The U.S. Department of Energy – Fossil Energy Office (DOE-FE) recently entered into an agreement with the West Virginia University Energy Institute (WVU EI), through a subaward from Leonardo Technologies, Inc (LTI), to conduct a Natural Gas Liquids assessment of the wet gas trends in the Utica and Marcellus gas plays.

The study will have three phases: (I) NGL producer engagement and methodology development; (II) development of NGL reserve estimates; and (III) development of NGL resource assessments.

In the Work Plan that is part of the subaward agreement between LTI and WVU EI, seven tasks were defined in Phase I, roughly in chronological order of effort, with seven deliverables. Task 1.3, *Prepare a crosswalk to explain how different resource assessments map to each other*, required WVU EI to deliver a report that compared the assessments of PGC and EIA.

3.0 Potential Gas Committee

PGC is a group of volunteers from industry, academia and government agencies that provides an assessment of the natural gas **resource** potential in the United States on a biennial schedule. By adding the volume of **proved reserves** made by EIA, PGC determines our **future gas supply** (i.e., to be produced). Adding cumulative production to this future gas supply results in an estimate of **ultimately recoverable resources (URR).**

In making their assessments, PGC volunteers examine the geology, drilling patterns and production data from 90 geologic provinces (56 onshore, 34 offshore). In their onshore assessment, PGC separates resources into depths less than 15,000 ft and depths between 15,000 ft and 30,000 ft.

Within the last couple decades, PGC began to include coalbed methane in their conventional resource category and added tight sands and shale to their traditional resource, which now includes conventional, tight sands and shale. PGC separates their assessment of traditional resources into Probable, Possible and Speculative categories based on drilling patterns and proximity to proven resources or reserves. PGC further divides these three assessments into Minimum, Most Likely and Maximum distributions. Reporting in this manner provides the user with a better understanding of the uncertainty and potential variability in resource assessments of any geologic province. PGC notes that this is not an exact science.

In addition to the aggregate sum of all "Most Likely" values in a province the committee reports "mean" values determined by a series of separate statistical aggregations. PGC believes that these mean values provide the most valid statistical basis for comparison of PGC results with those of other organizations.

3.1 Potential Gas Committee: Methodology for Assessments

PGC assessments are for resources that are judged to be recoverable in the future given adequate economic incentive and current foreseeable technology. PGC does not assume that these volumes will be developed and produced; instead these are volumes that could be developed if the need and economic incentives exist. PGC also assumes no government or regulatory restraints on development nor effects of access factors such as adequate infrastructure and natural gas pipelines.

PGC assessments of the U.S. natural gas resource do not include the volumes of proved reserves. In contrast, the gas volume estimates by EIA are limited to "proved, recoverable reserves of natural gas that have been established by drilling." Therefore, these EIA estimates do not include potential resources that may be discovered as a result of future exploration and development.

Also, PGC assessments do not include natural gas that may be produced in the future from sources not currently recoverable with existing or foreseeable technology and under current economic conditions (e.g., gas hydrates, geopressured-geothermal accumulations, deep-earth gas, extremely low-permeability formations). Furthermore, NGLs associated with shale gas are addressed only as a topic of future detailed discussion but are not subjects of potential evaluation at present.

PGC resource estimates are dynamic, not static; they change with drilling and production, requiring the movement of large volumes of natural gas from one resource category to a more appropriate category in the next biennial assessment. As an example, many of the revisions in resource assessments between successive PGC reports represent additions to proved reserves and the subtraction of this volume from the appropriate resource category, usually Probable

Resources, but also from Possible Resources due to successful exploration resulting in new field discoveries. With expanded drilling and production, areas with Possible Resources can be upgraded to Probable Resources, and areas of Probable Resources can be converted to production and proved reserves (see Figure 1).

Decreases in Probable Resources are due to drilling that extends the area of field production, shifting volumes of gas from Probable Resources to proved reserves in these wells. Increases in Probable Resources are due to new field discoveries in areas formerly designated as having Possible Resources. New drilling in these previously unproductive areas that discover natural gas results in declines in the volume of Possible Resources that are then shifted to Probable Resources and proved reserves in wells that are now in production.

Although not as common, a successful wildcat well in an area previously assessed as purely speculative can shift some Speculative Resource volumes to more appropriate categories, such as Probable near the new wells and Possible in other areas.

3.2 Potential Gas Committee: Definitions

Making accurate comparisons between/among assessments and estimates made by various groups is often confusing. To make an adequate comparison, it is necessary to understand what exactly is being assessed or estimated, and to understand the definition of the various categories of natural gas. The following definitions were taken from the latest biennial report of the PGC and are illustrated in Figures 1 and 2 (Martin, 2019; figures 46 and 47).

3.2.1 Recoverable Resources

The total volume of natural gas in rocks in the earth's crust is *the Total Natural Gas Resource*, including gas that is recoverable and gas considered to be unrecoverable under current economic conditions and technology. However, PGC only assesses what is recoverable, which at any point in time is a function of technology and economics. The *Recoverable Resource* base includes both *discovered* and *undiscovered natural gas*.

The *discovered natural gas* base includes historical production plus proved reserves in producing wells or undrilled infield wells (proved but undrilled, otherwise known as PUDs). *Discovered gas* also includes gas in known fields that can be recovered through field extensions or the future development of known pools and reservoirs.

The *undiscovered natural gas* base is the potential gas supply that can be produced following exploration, discovery and field/pool development. This undiscovered resource can exist in undiscovered pools in known fields as well as gas that may be discovered in new fields within geologic provinces that are presently productive, as well as other geologic provinces that currently are not productive.

3.2.2 Cumulative Production

Cumulative production represents the volume of natural gas that has been produced from known fields and marketed for sale, as well as gas used in field operations and delivered to end users.

This volume does not include associated gas that is extracted but then injected into the oil reservoir, nor noncombustible gas such as carbon dioxide that is removed from the gas stream prior to transportation and delivery. PGC does not estimate *cumulative production*. Instead, PGC relies on EIA data to arrive at cumulative production included in the total resource base.

3.2.3 Proved Reserves

As used by PGC and EIA, *proved reserves* are the estimated volumes of natural gas determined by geologic and engineering analyses to be recoverable in the future from known oil and gas reservoirs under current economic conditions and using current technology. These reservoirs have been shown to be productive through production or formation testing. In other words, *proved reserves* have been confirmed by drilling and testing.

Unfortunately, the definition of *proved reserves* often varies among reporting organizations and production companies.

3.2.4 Potential Resources

Potential Resources include all categories of the *undiscovered gas* resource plus that part of the *discovered gas* resource that has not been confirmed by drilling and testing and not included in *proved reserves*. Three categories are recognized and included in the PGC assessments: Probable, Possible and Speculative (see below). Both non-associated and associated or dissolved gas are included in all three categories.

3.2.5 Probable Resources

Probable Resources exist in known fields and are the most reliable of the three assessment categories. *Probable Resources* can exist in undrilled acreage associated with productive traps that can benefit from field extension, or in deeper pools under producing fields in formations that have not been tested locally but are known to be productive in the deeper pools of other fields.

3.2.6 Possible Resources

Possible Resources are undiscovered volumes of natural gas that are thought to exist outside of known fields and thus are assessed with a lower level of confidence. Even so, these are within a productive formation in the producing province. Their assessment is typically favorable because a current play or trend could be extended into the undrilled area, resulting in a new field discovery.

3.2.7 Speculative Resources

Speculative Resources are assessed at the lowest level of confidence because they are assumed to exist in formations or geologic provinces that are not yet proven to be productive, and very little, if no, technical data are available to evaluate them. These volumes are assumed to exist in potential deeper pools in an untested formation or in potential new fields in an untested formation with an untested trap.

3.2.8 Future Supply

The *future supply* of natural gas is the sum of *proved reserves* and the three categories of *Potential Resources*. The *total gas resource* includes this volume of *future supply* plus cumulative production.

4.0 Energy Information Administration (EIA)

EIA tracks numerous types of data such as prices, production, gas storage volumes, energy disruptions, refinery runs and proved reserves of oil and gas. For our purpose, *proved reserves* of natural gas and *technically recoverable resources* (TRR) are the most relevant to compare with assessments of the PGC.

4.1 EIA Proved Reserves

EIA defines proved reserves as the "estimated volume of hydrocarbons resource that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions." These reserves change each year due to new discoveries, a more complete appraisal of existing fields, production from these fields, as prices and costs change, and as technology evolves.

According to EIA data, a 21.5% decrease in the average annual spot price for natural gas in 2019 resulted in a 1.9% decrease in proved reserves, the first decrease since 2015. However, proved reserves in shale plays increased in 2019. The largest increase was in Ohio due to expansion of the Utica/Point Pleasant play, with the second largest increase in Pennsylvania due to extension of the Marcellus play.

EIA depends on industry contacts in their annual reviews of proved reserves. On their webpage EIA mentions the use of form EIA-23L, "*Annual Report of Domestic Oil and Gas Reserves*," sent to 412 operators, of which 372 responded providing coverage of 90% of the nation's oil and gas proved reserves. Coverage is developed for the entire United States, each state and regions within large producing states and offshore areas, and the resulting data are compared to data from the previous year.

EIA documents and reports the volumetric changes in proved reserves of crude oil (billions of barrels), crude oil and lease condensate (billions of barrels) and total natural gas (trillions of cubic feet), based on a variety of factors including extensions and discoveries, net revisions, net adjustments, sales and acquisitions, and estimated production to arrive at: (1) net additions to

U.S. proved reserves; (2) the new figure for U.S proved reserves; and (3) the percent change in U.S. proved reserves from the previous year.

NGLs extracted from wet gas at gas processing plants are included in the natural gas volumes. EIA addresses data trends in narrative form and discusses the reasons for changes in the trends for each of the hydrocarbon products (crude, natural gas, condensate).

Discoveries include new fields, new pays (shallower and deeper producing intervals) in existing fields and new drilling that results in field extensions. Extensions typically are the largest factor contributing to reserve additions. Revisions typically reflect changes made by operators due to changes in price or advances in technology.

4.2 Energy Information Agency: Technically Recoverable Resources

EIA provides additional information in their "Assumptions to the Annual Energy Outlook" (for example, EIA, 2021b), especially their assessment of "remaining technically recoverable resources" (TRR), defined as proved reserves plus unproven resources. "Unproven resources" are defined as "undiscovered resources that are located outside oil and gas fields where the presence of resources has been confirmed by exploratory drilling" that can be produced "using current recovery technology but without reference to economic profitability" (EIA, 2021b). Unproven resources in EIA terminology also include resources in undiscovered pools within confirmed fields, a definition that would equate to part of the PGC definition of Probable Resources (i.e., new pools that have been discovered but unconfirmed by drilling).

For continuous shale plays like the Marcellus and Utica, TRR is the product of area with potential (square miles), well spacing (wells per square mile) and estimated ultimate potential (EUR) per well. The natural gas resource in the east, an area estimated by EIA to contain 888.4 Tcf of TRR, is dominated by the Marcellus (318.9 Tcf) and Utica (274.2 Tcf). EIA further breaks down the TRR by the three areas in the Marcellus play identified by the USGS in their assessment: Foldbelt (0.2 Tcf); Interior (315.8 Tcf); and Western (2.9 Tcf). The Utica is divided into four areas: gas zone core (208.1 Tcf); gas zone extension (5.1 Tcf); oil zone core (1.9 Tcf); and oil zone extension (0.1 Tcf).

In this same report (EIA, 2021b), EIA also reported their updated assessment NGPLs using gas-to-liquids ratios and the purity splits of the NGPL barrels that were updated starting with their 2017 report. For the Marcellus play, the total TRR for NGPL is 15.9 Bbbls, mostly in the Marcellus Interior (15.7 Bbbls). For the Utica, the total resource is estimated by EIA to be 6.5 Bbbls, mainly in the gas zone core (3.9 Bbbls) and gas zone extension (2.5 Bbbls) areas.

4.3 Energy Information Agency: Definitions

The following definitions are used by EIA and can be found on their website.

4.3.1 Proved Reserves

Proved reserves are “estimated volumes of hydrocarbon resources that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions.” This definition is accepted and used by PGC.

4.3.2 Nonassociated Natural Gas

Nonassociated natural gas or gas well gas is “natural gas not in contact with significant quantities of crude oil in a reservoir.” EIA notes that most shale natural gas is nonassociated.

4.3.3 Associated-dissolved Natural Gas

Associated-dissolved natural gas, also called casinghead gas, is the “combined volume of natural gas that occurs in oil reservoirs as either free gas (associated) or as gas in solution (dissolved).”

4.3.4 Coalbed Natural Gas

Coalbed natural gas (a discontinued term) is now included with conventional natural gas.

4.3.5 Natural Gas from Shale Plays

Natural gas from shale plays requires hydraulic fracturing and usually horizontal drilling and accounted for 71% of U.S. proved reserves in the 2019 report. In state rankings of the latest report, Pennsylvania is #1, Ohio #3 and West Virginia #4. The Marcellus play in Pennsylvania and West Virginia is the largest by far among U.S. natural gas shale plays.

4.3.6 Dry Natural Gas

Dry natural gas is defined as the volume of gas after impurities and NGLs are removed, typically at a gas processing plant, although some natural gas is sufficiently dry to meet pipeline standards without further processing.

EIA calculates its estimate of *dry natural gas proved reserves* by first “estimating the expected yield of natural gas plant liquids from total natural gas proved reserves and by then subtracting the gas equivalent volume of the natural gas plant liquids from total natural gas proved reserves.”

Essentially, EIA makes two estimates - *natural gas proved reserves* and the volume that will be extracted from that volume in a gas processing plant - then subtracts the two. The result is *dry natural gas proved reserves*.

4.3.7 Lease Condensate

Lease condensate is a mixture, typically of liquids heavier than pentanes, that are extracted at lease processing facilities. Lighter gas liquids, such as propane, butane, and natural gasolines are extracted at gas processing plants. Lease condensate typically is included in the oil stream.

4.3.8 Natural Gas Plant Liquids

Natural gas plant liquids typically stay in the natural gas stream after it has passed through the lease separation facilities, and are extracted downstream at gas processing plants, fractionators and cycling plants.

4.4 Energy Information Agency: Proved Reserves in Non-Producing Formations

EIA recognizes two types of proved reserves not in currently producing reservoirs: *proved, developed, non-producing proved reserves* (PDNPs) and *proved, undeveloped reserves* (PUDs).

4.4.1 PNNPs

PDNPs include existing production wells that are shut in and awaiting workover; drilled but awaiting completion; drilled awaiting hookup to a pipeline; or behind the pipe reserves awaiting depletion of producing intervals before they can be completed (recompletions).

4.4.2 PUDs

PUDs are offset well locations awaiting drilling and completion that have to meet certain requirements: (1) they must be direct offsets to commercial producing wells; (2) they must be with reasonable certainty within the producing limits of the target formation; (3) they must be in compliance with spacing regulations, if applicable; and (4) they must be drilled in a reasonable time frame, typically five years.

5.0 References Cited

Martin, 2019, Potential Supply of Natural Gas in the United States – Report of the Potential Gas Committee, December 31, 2018; Potential Gas Agency, Colorado School of Mines, Golden, CO 80401-1887, 106 p.

U.S. Energy Information Administration (EIA), 2021a, Proved reserves of crude oil and natural gas in the United States, year-end 2019; www.eia.gov/naturalgas/crudeoilreserves/pdf/usreserves.pdf, 45 p.

U.S. Energy Information Administration (EIA), 2021b, Assumptions to the annual energy outlook 2021: oil and gas supply module; www.eia.gov/outlook/aeo/assumptions/pdf/oilgas.pdf, 22 p.

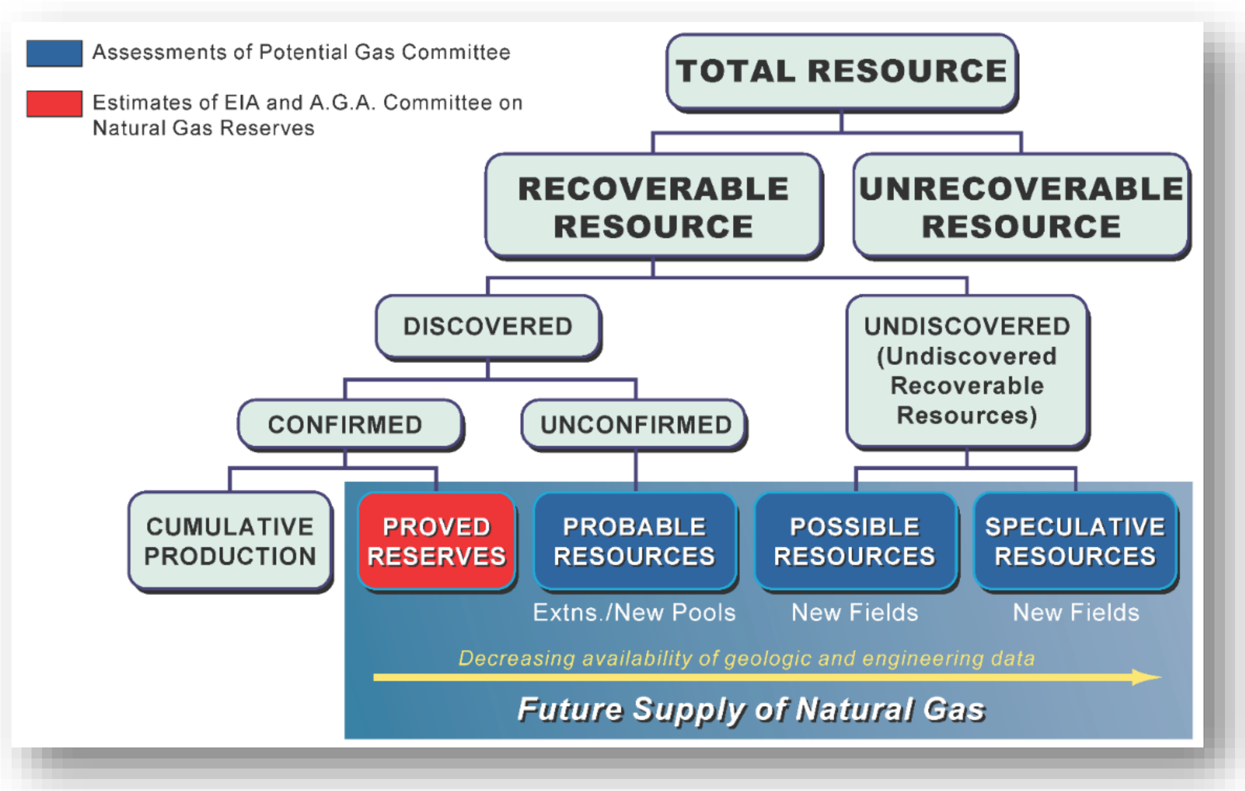

Figure 1. Classification of the total natural gas resource adopted by the PGC (source, Martin, 2019, figure 46).

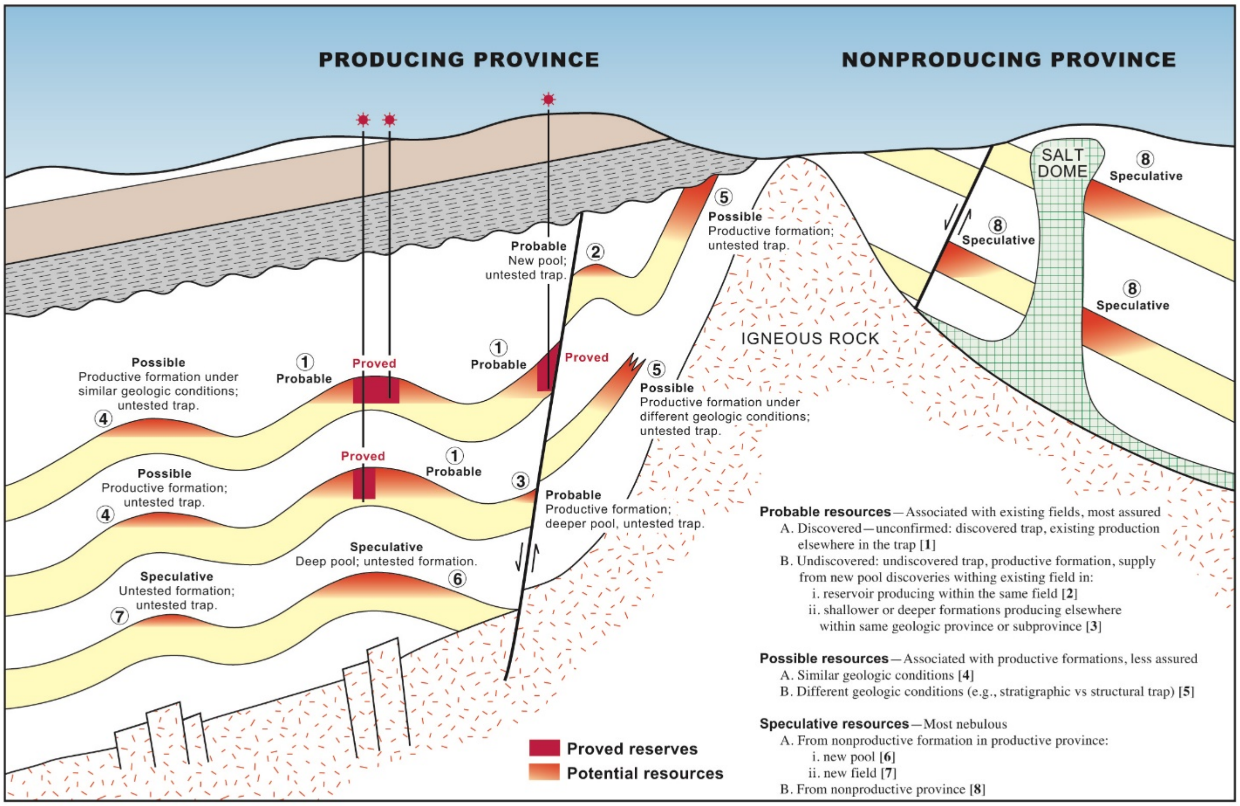

Figure 2. Hypothetical cross section illustrating the various categories and types of occurrence of the various categories of natural gas resources recognized by the PGC (source, Martin, 2019, figure 47).

Appendix B

Key Questions to Help Populate Data for Updated Resource Assessments and Definition of Wet Gas Trends in the Marcellus and Utica Plays

Phase 1 – NGL Producer Engagement and Methodology Development

In the pre-decisional document provided to WVU EI, DOE specified that their support of this work is contingent upon the participation of NGL producers who will share NGL production data, including not only the volumes produced but also the composition of the gas stream at the wellhead or some other useful place in the NGL supply chain. DOE also stated the importance of collecting data on the volumes of NGLs rejected into the natural gas stream that ultimately will be burned. A main concern is the large gap in EIA data from 2018 regarding ethane production and rejection, a gap spanning from 150,000 to 685,000 bbls/day.

In the Work Plan that is part of the subaward agreement between LTI and WVU EI, seven tasks were defined in Phase I, roughly in chronological order of effort, with seven deliverables. Task 1.1 requires WVU EI to participate in bi-weekly progress meetings with the DOE project manager. Task 1.2 requires WVU EI to assist DOE in their data collection effort and is described below with the first deliverable and deadline for that deliverable. Task 1.2 also required WVU EI to provide a list of producing companies that should be contacted, and contact personnel at those companies. This separate deliverable is included in Appendix C.

Task 1.2 – Support DOE's Outreach to NGL Producers and Develop Methodology

The recipient will assist DOE outreach to key producers in the Appalachian basin. Specific activities include the following:

- Assist DOE with a list of key producers in the wet gas trends of the Utica and Marcellus plays.
- Identify key contact persons in these companies.
- Attempt to get a broad geographic distribution of producers in both plays.
- Provide DOE with a list of key questions that should be asked of participating producers that will need to be addressed to obtain the necessary data for improved resource assessments and estimates.
- Serve as an expert advisor to DOE on developing the methodology
- Seek to enlist the relevant geological surveys in an advisory role, namely, to provide relevant data and serve as technical reviewers.

Deliverable: Recipient will provide a list of key questions to help populate data for updated resource assessments.

<u>Key Questions to Ask Industry Producers</u>

WVU EI assumes that DOE participants will have their own questions to ask key NGL producers but offers a few other questions for DOE to consider. In their initial discussions, the WVU EI principle investigator and the cooperating geological survey team members considered two questions, the first being "Who should be contacted?" - a contact in the engineering departments of the gas producer, or a member of the leadership team who ultimately would make the decision on whether or not to participate. With that in mind, we began a search for the names of the key contacts and their contact information.

The second question under discussion was "What questions should be asked of the operators?" (and by association, "How many could be asked before the company said enough is enough and decided not to fully participate?") Ultimately, we decided to provide a set of questions and let DOE decide how many and which ones to ask, and to separate questions into three categories: (1) key data that must be collected for a resource assessment; (2) data used to define the western and eastern boundaries of the wet gas trends; and (3) generalized questions that could provide a better understanding of, and confidence in, datasets collected from different producers.

Data for resource assessment:

- What natural gas production data do you have on individual wells in the wet gas trends?
- Do you determine the composition of the gas stream from each well, and if so, what composition data can you share?
- Where do you record your NGL volumes (stock tank, sales meter, midstream company)?
- What is the quantity of NGLs rejected into the marketed gas stream? (i.e., How much NGL do you blend down into dry gas lines due to poor liquids pricing?)
- What volume of NGLs must be left in the gas stream to meet minimum BTU pipeline requirements?
- What is the volume of NGLs that can be left in the gas stream and still meet maximum BTU pipeline requirements?
- What is the volume of NGLs/Mcf wet gas?
- What is the ratio of NGL components extracted from the gas stream?
- Do you have BTU data for individual wells?

Data to help define the wet gas trends:

- How do you anticipate NGL volumes before you drill a well? (i.e., How do you know you will be in the wet gas trend, especially near the eastern and western boundaries of the shale plays?)
- What data do you use to define the edges of the wet gas trend?
- What are the cutoff parameters used to define the oil/wet gas boundary?
- Where is the wet gas/dry gas boundary on the eastern edge of each shale play?

Other:

- How do you measure your gas composition (by assay or other means)?
- How often do you measure your gas composition?
- Do your gas compositions and NGL yields change through time? And if so, what is the relationship between these two parameters?
- How could state agencies better streamline the NGL reporting process?
- What could state or federal agencies do to encourage NGL production?
- How would your company be affected if new NGL processors or end users moved into Appalachia?
- What barriers exist to increasing NGL production in Appalachia?

Appendix C

Key Producers and Contacts

Ohio (Utica Production)	Key Contacts	Phone
EAP Ohio LLC	Ray Walker, COO	281-254-7070
Antero Resources Corp	Al Schopp, Regional Senior Vice President	303-357-7325
Ascent Resources Utica LLC	Keith Yankowsky, COO	405-608-5544
Gulfport Appalachia LLC	Donnie Moore, COO	405-252-4600
Eclipse Resources LLC	Christopher K. Hulburt, Executive VP	814-409-7002
Pennsylvania (Marcellus Production)		
EQT	Toby Rice, President & CEO	412-553-5700
Range Resources Corp	Dennis Degner, Sr. VP and COO	724-743-6700
CNX	Chad Griffith, COO	724-485-4000
West Virginia (Marcellus Production)		
Southwestern Energy	Clay Carrell, Executive VP & COO	832-796-1000
Antero	Al Schopp, Regional Senior Vice President	303-357-7325
Tug Hill	Evan Radler, COO	817-632-5200
Jay-Bee Oil & Gas	Randy Broda, President	908-686-1493
HG Energy	Matt Lupardus, Vice President	304-420-1127
CNX	Chad Griffin, COO	724-485-4000
EQT	Toby Rice, President & CEO	412-553-5700

Company Addresses

Ohio (Utica Production)

EAP Ohio LLC	5847 San Felipe Street, Suite 400, Houston, TX 77057
Antero Resources Corp	1615 Wynkoop Street, Denver, CO 80202
Ascent Resources Utica LLC	P.O. Box 13678, Oklahoma City, OK 73134
Gulfport Appalachia LLC	3001 Quail Springs Parkway, Oklahoma City, OK 73134
Eclipse Resources LLC	2121 Old Gatesburg Road, Suite 110, State College, PA 16803

Pennsylvania (Marcellus Production)

EQT	625 Liberty Avenue, Pittsburgh, PA 15222
Range Resources Corp	3000 Town Center Blvd, Canonsburg, PA 15317
CNX	1000 Consol Energy Drive, Canonsburg, PA 15317-6506

West Virginia (Marcellus Production)

Southwestern	10000 Energy Drive, Spring, TX 77389
Antero Resources Corp	1615 Wynkoop Street, Denver, CO 80202
Tug Hill	1320 S. University Drive, Suite 500, Fort Worth, TX 76107
Jay-Bee Oil and Gas	3570 Shields Hill Road, Cairo, WV 26337 (304-628-3111)
	16 S. Ave W, Ste 118, Cranford, NJ 07016 (908-686-1493)
HG Energy	520 Dupont Road, Parkersburg, WV 26101
CNX	1000 Consol Energy Drive, Canonsburg, PA 15317-6506
EQT	625 Liberty Avenue, Pittsburgh, PA 15222