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September 12, 2016

Via E-Filing

Federal Energy Regulatory Commission
888 First Street NE, Room 1A
Washington, DC 20426

Attn: Kimberly D. Bose, Secretary

Re: PennEast Pipeline Company, LLC;
Draft Environmental Impact Statement for PennEast Pipeline Project,
Docket No. CP15-558-000

Dear Secretary Bose,

Intervenor Clean Air Council ("Council") hereby submits the following comments on the Draft Environmental Impact Statement ("draft EIS") prepared by the Federal Energy Regulatory Commission ("FERC" or the "Commission") with respect to PennEast Pipeline Company LLC's ("PennEast") proposed PennEast pipeline project (the "Project"). These comments are timely submitted.

The Clean Air Council is a non-profit environmental organization headquartered at 135 South 19th Street, Suite 300, Philadelphia, Pennsylvania 19103. For nearly 50 years, the Council has fought to improve the air quality across the Mid-Atlantic region. The Council has members throughout the region. The Council works to protect everyone's right to breathe clean air.

Clean Air Council's comments address: (1) the lack of required public purpose of the Project as evidenced by the discussion of the no-action alternative (2) inadequate consideration of cumulative impacts and (3) incomplete analysis of the air quality impacts of the Kidder Compression station.

Before turning to these specific issues though, the Council must first join with the literally thousands of concerned citizens who have commented on the sheer volume of surveys,

assessments, and mitigation plans that are glaringly absent from the draft EIS and FERC's alarming willingness to reach conclusions regarding impacts even without this information. While the Council will speak to some examples of this below, there is not adequate time in the present comment period to carefully discuss each such deficiency. FERC's method of addressing a number of deficiencies in the draft EIS, however, demands immediate attention.

FERC indicates multiple times in the draft EIS that PennEast will be able to complete necessary surveys once it is granted the authority to take the impacted land through eminent domain. Let us address this seeming attempt to blame landowners for the dearth of information in the draft EIS squarely. Regardless of landowner sentiment or PennEast's failure to foster relationships with impacted residents[1], FERC is statutorily mandated to provide the public with a full and accurate assessment of the Project's environmental impacts and alternatives *prior* to FERC giving PennEast the power to take property. For FERC to grant PennEast the right to take private property before providing the public with critical information would undermine the public's right to weigh in on FERC's analysis through hearings and comments and diminish the integrity of FERC's project approval process. It would also be illegal.

The Council thus requests, pursuant to 40 CFR § 1502.9, that FERC prepare and circulate a revised draft EIS that incorporates and considers all of the surveys and mitigation plans that FERC has identified as missing but is presently willing to proceed without.[2] Upon publication of that revised draft EIS, the Council requests FERC open a new comment period, giving the public a full and fair opportunity to respond to all information regarding how the Project will impact their communities prior to FERC rendering a decision that could result in PennEast taking private property. As FERC continues to analyze the proposed PennEast Project, please consider the following:

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[1] While it may never be realistic for a company to receive 100% landowner cooperation, surely PennEast could do more to provide complete and accurate information regarding impacts. Instead of PennEast meeting skepticism over the need for the Project or PennEast's methods with open dialog, information, and fair dealing, commenters have documented landowners being harassed by PennEast. Many concerns raised in comments have been ignored or handled dismissively by PennEast and FERC, with the public's say in what will happen to their land, water, and air limited by a short comment period, and isolating, "public" hearings. This approach to addressing residents and landowners who would be most impacted by this project has undoubtedly soured relations and made it more difficult to proceed. Furthermore, a strong, evidenced-based case for public need would likely go a long way in garnering cooperation from the public.

[2] "If a draft statement is so inadequate as to preclude meaningful analysis, the agency shall prepare and circulate a revised draft of the appropriate portion." 40 CFR § 1502.9(a); *see also* § 1502.9(c)(1)(ii).

1. PennEast has not shown that the Project would have the constitutionally required public purpose, a needed showing to establish public convenience and necessity.

It is PennEast's burden to show that the use of eminent domain for the Project would be constitutional.[3] In the absence of such a showing, FERC cannot issue a certificate of public convenience and necessity. PennEast's failure to show a public purpose for the Project is evidenced in the draft EIS, specifically in FERCs analysis of project alternatives.

A. It is not within the power of the federal government to take private property for a private purpose.

The right to private property is deeply rooted in American law. It shows up in the inimitable prose of the Declaration of Independence as the "pursuit of happiness,"[4] and in the Bill of Rights in the takings and due process clauses of the Fifth Amendment. The Fifth Amendment guarantees that private property may not be condemned by the state but for public use and for just compensation. U.S. Const. amend. V.

Over the centuries since the adoption of the Bill of Rights, courts and condemnors have gradually weakened those guarantees. The U.S. Supreme Court no longer reads "public use" to mean "use by the public," as it once did, reading it instead to mean "public purpose." The Supreme Court now reads even "public purpose," in turn, as encompassing takings with a significant element of private purpose. *See Kelo v. City of New London*, 545 U.S. 469 (2005). Nonetheless, the Fifth Amendment has not been eroded away completely. Where public use is only incidental to private purpose, the taking is outside the power of the government. *Kelo*, 545 U.S. 490-491 (Kennedy, J., concurring).

B. FERC cannot grant a certificate of public convenience and necessity for a project lacking a public purpose.

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[3] It is the applicant's burden to present facts in its application demonstrating that the proposed natural gas project would be required by the present or future public convenience and necessity. 18 CFR § 157.6(b)(2) (An application must include "[t]he facts relied upon by applicant to show that the proposed service, sale, operation, construction, extension, or acquisition is or will be required by the present or future public convenience and necessity.)

[4] The U.S. Supreme Court has written:

> Rights to life, liberty, and the pursuit of happiness are equivalent to the rights of life, liberty, and property. These are the fundamental rights which can only be taken away by due process of law, and which can only be interfered with, or the enjoyment of which can only be modified, by lawful regulations necessary or proper for the mutual good of all; and these rights, I contend, belong to the citizens of every free government.

Slaughter-House Cases, 83 U.S. 36, 116 (1873).

The Natural Gas Act confers upon the holder of a certificate of public convenience and necessity for a pipeline the right to use eminent domain to build the pipeline. 15 U.S.C. § 717f(h). That the legislature has chosen to endow duly certificated companies with eminent domain power does not erase the constitutional requirement that private property not be taken but for public use. To the contrary, because FERC is the arm of the federal government deciding whether to grant a certificate of public convenience and necessity, the certificate applicant must demonstrate to FERC that the proposed project would be for public use. 15 U.S.C. § 717f(c)(1)(A). It is FERC's obligation in turn to ensure that certificates only issue where the use of eminent domain would be constitutional.[5]

Here, FERC cannot constitutionally grant PennEast eminent domain powers for the Project without grounds for finding public use, which is primarily a factual question. *Southern Power Co. v. North Carolina Public Service Co.*, 263 U.S. 508, 509 (1924); *County of Allegheny v. Frank Mashuda Co.*, 360 U.S. 185, 190 (1959). If evidence supporting a showing of public use is not found on the record in this proceeding, the issuance of a certificate would be arbitrary and capricious. *See Missouri Pub. Serv. Comm'n v. F.E.R.C.*, 337 F.3d 1066, 1070 (D.C. Cir. 2003) ("FERC must articulate the critical facts upon which it relies, and when it finds it necessary to make predictions or extrapolations from the record, it must fully explain the assumptions it relied on to resolve unknowns and the public policies behind those assumptions.") (quotation marks and citations omitted).

However, as a matter of policy, FERC does not seek or gather evidence on public use or public purpose, which are different from "public convenience and necessity." FERC's publication, Statement of Policy for Certification of New Interstate Natural Gas Pipeline Facilities,[6] explains FERC's procedure for evaluating whether to issue a certificate for a new pipeline project. FERC's first step is to examine whether the project is financially viable without subsidization from existing customers.[7] This step measures market demand, which is not the same as public need, let alone public use, neither of which FERC evaluates at this threshold stage. The second step is to determine whether the applicant "minimized" harms to others and what residual adverse effects remain.[8] The third step takes into account public benefits, including need, balancing it against adverse effects. "Rather than relying only on one test for

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[5] Courts hearing condemnations under the Natural Gas Act have generally held that their only function is enforcement, and that they do not have the power to question the use of eminent domain. *Kansas Pipeline Co. v. 200 Foot by 250 Foot Piece of Land*, 210 F. Supp. 2d 1253, 1256 (D. Kan. 2002) ("The court does not have jurisdiction to review a collateral attack on the FERC certificate.") (citing *Williams Natural Gas Co. v. City of Oklahoma City*, 890 F.2d 255, 262 (10th Cir. 1989)). FERC cannot, then, assume that another entity will protect citizens' constitutional rights under the Fifth Amendment.

[6] Statement of Policy for Certification of New Interstate Natural Gas Pipeline Facilities, PL99-3-000 (09/15/99) (clarified at PL99-3-001 and -002).

[7] *Id.* at 19-22.

[8] *Id.* at 23.

need, the Commission will consider all relevant factors reflecting on the need for the project. These might include, but would not be limited to, precedent agreements, demand projections, potential cost savings to consumers, or a comparison of projected demand with the amount of capacity currently serving the market."[9]

At no step does FERC purport to determine whether the pipeline will be for a public purpose. Thus the constitutional flaw here inheres in FERC's policy as much as in its evaluation of PennEast's application. Given this context, it is unsurprising that the draft EIS does not explicitly answer the question of whether the PennEast project has a public purpose. The draft EIS does, however, discuss the purpose of the PennEast project through its analysis of alternatives. In doing so, it provides strong evidence that the Project serves a private purpose.

C. The alternative action analysis is incomplete and supports a finding of private purpose.

40 CFR § 1502.14 mandates that FERC "rigorously explore and objectively evaluate all reasonable alternatives" to the proposed action and present "a clear basis for choice among options by the decision maker and the public." This rigorous analysis must include an evaluation of "the alternative of no action." *Id.* Nevertheless, in the 1169 pages of the draft EIS, discussion of the no- action alternative, including the possibility that an unmet energy demand - if it exists- could be addressed with renewables, is dismissed in a single page. The main reason provided in the draft EIS for disregarding the no-action alternative is it fails to satisfy the objectives of the Project:

> While the no-action alternative would eliminate the short- and long-term environmental impacts identified in the EIS, the stated objectives of PennEast's proposal would not be met. We evaluated the use of alternative energy sources and the potential effects of energy conservation, but these measures similarly would not satisfy the objectives of the Project, provide an equivalent supply of energy, or meet the demands of the Project Shippers.[10]

FERC's decision to focus on project objectives is a small step in the right direction, at least for purposes of evaluating the no-action alternative. Unlike other project alternatives, the no-action alternative does not include facilities or routes that can be compared directly acre-for-acre and impact-for-impact with the proposed project. Instead, weighing a project against the no-action alternative necessarily calls for the project to be stripped down to its core purpose and a value judgment as to whether that purpose is justified in light of the costs to achieve it.

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[9] *Id.* at 23.
[10] Draft EIS 5-18

Analysis of the no-action alternative is thus closely intertwined with the question of whether a project has a public or private purpose. An actor's stated objectives may serve as a starting place for identifying the true purpose of the project, but must be scrutinized carefully, and supported by evidence. Anyone can claim a public purpose or inflate the value of a proposed action. Here, it is up to FERC to determine the purpose of the Project and to make a well-reasoned decision as to whether that purpose is worth pursuing. The analysis of the no-action alternative set forth in the draft EIS falls far short of providing a clear basis for FERC's decision to favor the Project. FERC has not endeavored to identify the purpose of the project and has treated the pursuit of PennEast's stated objectives as paramount without assessing the value of those objectives or the cost to achieve them. This is unacceptable.

As illustrated above, two objectives seem to be the focus of FERC's analysis of alternatives: 1.) providing approximately 1.1 MMDth/d of year-round natural gas transportation service from northern Pennsylvania to markets in New Jersey, eastern and southeastern Pennsylvania, and surrounding states; and 2.) meeting the needs of the Project shippers.

In attempt to prove that a demand exists for an additional 1.1 MMDth/d of natural gas, PennEast has reported that 90 percent of the Project design capacity is already under contract with shippers. FERC relies heavily on this assertion. Presumably if stronger evidence of market demand had been made available to FERC, that evidence would have been showcased prominently in the draft EIS to support FERC's ultimate conclusion that the Project presented the best alternative. It was not.[11] Yet this 90 perecent statistic is misleading and not itself evidence of unmet public demand for natural gas.

PennEast has identified twelve entities as having entered contracts for 90 percent of the pipeline capacity. PennEast itself comprises six corporations. Two of the six corporations that makeup PennEast, UGI Energy Services, LLC and PSEG Power (Public Service Enterprise Group), are explicitly listed as shippers as well. New Jersey Natural Gas Company, a shipper, is the

[11] In fact, expert analysis of the market has concluded that additional natural capacity in this region is unnecessary. There is strong evidence that the market is not being driven primarily by natural gas consumer demand, and that there is a great risk of overbuilding. FERC has found that "overbuilding ... can exacerbate adverse environmental impacts, distort competition between pipelines for new customers, and financially penalize existing customers of expanding pipelines and customers of the pipelines affected by the expansion." PL99-3-001 at 4. The evidence for overbuilding is strong. Rusty Braziel, energy consultant and former Vice President of Business Development for The Williams Companies, recently warned a natural gas industry conference that the pipeline projects currently planned to take gas from the Marcellus and Utica shales would likely create a significant overcapacity compared to projected production volumes. *See* Jeremiah Shelor, "Marcellus/Utica On Pace for Pipeline Overbuild, Says Braziel," *Natural Gas Intelligence*, June 8, 2016, available at http://www.naturalgasintel.com/articles/106695-marcellusutica-on-pace-for-pipeline-overbuild-says-braziel. Braziel's analysis is echoed by a report titled "Risks Associated with Natural Gas Pipeline Expansion in Appalachia," published in April 2016 by the Institute for Energy Economics and Financial Analysis, attached hereto as Exhibit A. Among the report's conclusions, based on a broad review of market conditions and analyst reports, is that "[p]ipelines out of the Marcellus and Utica region are being overbuilt." *Id.* at 1, 3-13.

"principal subsidiary of New Jersey Resources"[12] while NJR Pipeline Company, one of the corporations that is PennEast, is a wholly owned subsidiary of New Jersey Resources.[13] South Jersey Gas, another shipper, is a business segment of SJI Industries, while SJI Midstream, part of PennEast, is a direct subsidiary of SJI Industries.[14] Spectra Energy Partners is part of PennEast and is the operator and 100% owner of Texas Eastern Transmission, a shipper.[15] The shipper Pivotal Holdings (d/b/a Elizabethtown Gas) is a subsidiary of AGL Resources, part of the PennEast corporation.[16] In sum, all six of the corporations that joined to form PennEast are also shippers, outright owners of shippers, or are otherwise directly and substantially connected to one of the shipping companies. These six PennEast shippers account for 735,000 MMDth/d, or 74 percent of the natural gas capacity that is under contract. The remaining six shippers, one of which recently filed for bankruptcy, account for 26 percent of the contracted Project capacity, and only 23 percent of total proposed Project capacity. See Figure 1.

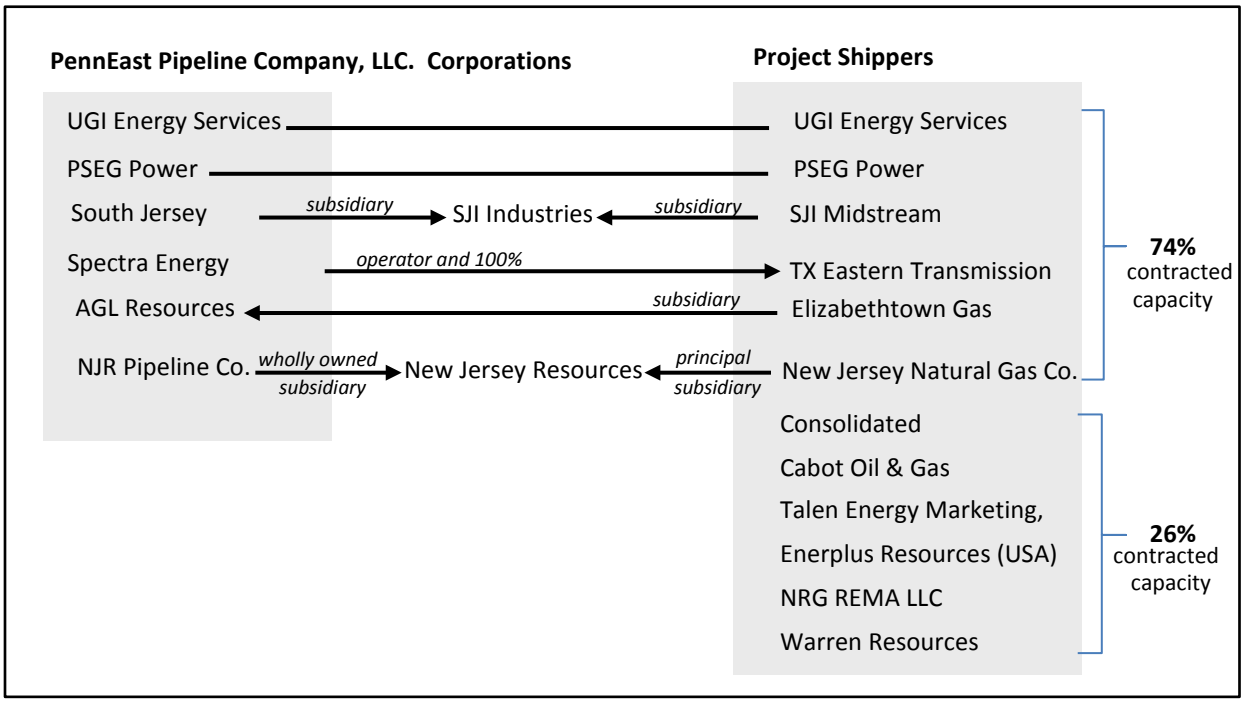

Figure 1

[12] https://www.njng.com/about/index.asp.

[13] New Jersey Resources created NJR Pipeline Company as part of a "strategic decision to begin investing in the midstream asset sector" to provide "'NJR's shareowners with another source of earnings." http://www.njresources.com/about/midstream.asp, *See also* http://penneastpipeline.com/member-companies/

[14] http://www.reuters.com/finance/stocks/companyProfile?symbol=SJI, http://penneastpipeline.com/member-companies/

[15] http://www.spectraenergy.com/Operations/US-Natural-Gas-Operations/US-Pipelines/Texas-Eastern-Transmission/

[16] AGL Resources became Southern Company Gas in July 2016. http://aglresources.com/about/distribution_eli.aspx

Thus, when PennEast states one of its objectives is to meet the demands of its shippers, it is identifying a private –not public- purpose; it is readily apparent that shippers have come together and formed PennEast to serve themselves. Similarly, where the vast majority of the PennEast pipeline capacity is tied up in contracts with the PennEast shippers, these contracts cannot serve as a proxy for public demand for natural gas. The validity of PennEast's primary objective, to supply 1.1 MMDth/d of additional natural gas, is therefore dubious. Public demand for this additional natural gas remains unproven and we are left only with proof that the demand for this project arises from PennEast itself. In an analysis of the no-action alternative, PennEast's private purpose for this project cannot be justified in light of the truly significant public costs of the project. FERC, however, does not attempt to complete this analysis.

A couple of additional points regarding FERC's evaluation of the non-action alternative are worth noting. First, FERC argues that the Project is the preferred alternative because the no-action alternative might result in some other pipeline being developed to suit the shipper's demands.[17] This is a false dilemma that treats the construction of pipelines as a forgone conclusion and negates the discretionary power imbued in FERC. FERC would be responsible for evaluating any such interstate pipeline and cannot evade the ultimate question of the appropriateness of this pipeline by kicking the can down the road for a future review.

Second, FERC argues that while the public demand for additional energy could potentially be met through alternative fuel or renewable energy sources, the construction of new infrastructure "would result in environmental impacts that could be equal to or greater than those of the Project."[18] Those impacts, however, are never actually described, must less "rigorously" and "objectively" explored or "considered in detail" in the draft EIS as mandated by 40 CFR § 1502.14. FERC offers a separate reason for its disregard of clean energy and energy efficiency alternatives a few pages later in the draft EIS, asserting that because alternative energy projects would be managed by the states, such projects are outside of FERC's jurisdiction and therefore the scope of the draft EIS.[19] This is simply an inaccurate application of law. The Council of Environmental Quality's regulations on alternative analysis specifically require FERC to consider alternatives outside its jurisdiction.[20]

For the foregoing reasons, the Council respectfully requests that upon submission of a revised draft EIS, in compliance with NEPA, FERC give full consideration to the no-action alternative and discussion of renewables. This analysis must focus on comparing impacts of

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[17] Draft EIS 3-3
[18] Id.
[19] Id.
[20] 40 CFR § 1502.14(c)(Agencies shall "include reasonable alternatives not with the jurisdiction of the lead agency.")

alternatives, and not unquestioningly accepting PennEast's objectives as the true purpose of project. The alternatives analysis is the "heart" of NEPA and is necessary to provide the decision maker and the public with a "clear basis for choice" among the options.[21] This is a critical aspect of the EIS not only because it is mandated, but because of the significant overlap between the no-action alternative and the ultimate question which FERC must decide: whether there is public purpose for this project. Based on the evidence presented, FERC must conclude there is not.

2. <u>FERC has failed to thoroughly address the cumulative impacts of the Project.</u>

An EIS must consider cumulative impacts associated with a federal action.[22] A cumulative impact is: "The impact on the environment that results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (Federal or non-Federal) or person undertakes such other actions. Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time."[23]

CEQ has long made clear that the action-forcing clause in NEPA, "'major Federal actions significantly affecting the quality of the human environment,' is to be construed by agencies with a view to the overall, cumulative impact of action proposed (and further actions contemplated)."[24] Significance, in this context, requires consideration of "[w]hether the action is related to other actions with individually insignificant but cumulatively significant impacts. Significance exists if it is reasonable to anticipate a cumulatively significant impact on the environment. Significance cannot be avoided by terming an action temporary or by breaking it down into small component parts."[25]

Moreover, FERC must take into consideration the cumulative effects of actions similar to the proposed action, both existing and reasonably foreseeable.[26] A good illustration of a proper

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[21] 40 CFR § 1502.14

[22] *Id.* § 1508.25(c)(3); *see also Kern v. Bureau of Land Mgmt.*, 284 F.3d 1062, 1076 (9th Cir. 2002).

[23] 40 C.F.R. § 1508.7

[24] Council on Envtl. Quality, Statements on Proposed Federal Actions Affecting the Environment, 35 Fed. Reg. 7,390, 7,391 (May 12, 1970).

[25] 40 C.F.R. § 1508.27(b)(7)

[26] *See, e.g.*, *Nat'l Audubon Soc'y v. Dep't of Navy*, 422 F.3d 174, 196-97 (4th Cir. 2005) (cumulative impact analysis of proposed Navy landing field should have considered whether flights to and from the field would "add any significant noise-related or other environmental impacts to those that the existing military airspace currently imposes," as well as the cumulative effects of reasonably foreseeable designation of additional military operating areas); *Lands Council v. Powell*, 395 F.3d 1019, 1027 (9th Cir. 2005) (environmental impact analysis of timber harvesting activity was inadequate where the agency did not consider "in detail past timber harvesting projects and the impact of those projects," in combination with the proposed project).

cumulative impacts analysis can be found in *Grand Canyon Trust v. FAA*.[27] That case concerned the Federal Aviation Administration's (FAA) Environmental Assessment (EA) on the effects of the construction of an airport near Zion National Park.[28] The court faulted the FAA for considering only the noise impacts on the park that would result from the construction of the airport without also considering the "total, incremental impacts of various man-made noises, such as the 250 daily aircraft flights near or over the Park that originate at, or have as their destination, airports other than" the one at issue.[29] The court similarly faulted the FAA for failing to consider the cumulative impacts of the planned expansions of other regional airports.[30]

Although FERC has previously distinguished *Grand Canyon Trust* on the ground that the activities the court determined to be required in the EA were "similar to the agency's proposed action," the distinction is irrelevant.[31] The CEQ regulation defining "cumulative impact" in no way limits a cumulative impacts analysis to the effects of actions "similar" to the one at issue.[32] Moreover, the similarity of the actions was not relevant to the *Grand Canyon Trust* court's decision except insofar as it determined that a cumulative analysis of the effects of noise on the park should consider other sources of noise, which necessarily included noise from similar activities.[33] FERC's tortured reading of *Grand Canyon Trust* is little more than an attempt to dodge the requirements of NEPA.

In another instructive case, *United States v. 27.09 Acres of Land*, the Postal Service proposed a project that would involve the paving of six acres of undeveloped land adjacent to an existing airport and highway.[34] The district court found the agency's finding of no significant impact in its environmental assessment ("EA") to be arbitrary and capricious because the EA's consideration of the proposed facility's cumulative impact on water quality only took into account "interaction of expected runoff from the site with present levels of runoff from the [already existing] nearby" airport and highway.[35] The court found that "[t]he failure of the EA to consider the facility's cumulative impact in conjunction with nearby anticipated development

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[27] 290 F.3d 339 (D.C. Cir. 2002).
[28] *Id.* at 340.
[29] *Id.* at 346.
[30] *Id.*

[31] *Cent. N.Y. Oil & Gas Co., LLC*, 138 F.E.R.C. P61,104, at 30 (2012) (Order on Rehearing, Clarification and Stay).

[32] *See* 40 C.F.R. § 1508.7.

[33] *See Grand Canyon Trust*, 290 F.3d at 346 ("Nor does the EA address the impact, much less the cumulative impact, of noise in the Park as a result of other activities, such as the planned expansions of other regional airports that have flights near or over the Park.").

[34] 760 F. Supp. 345 (S.D.N.Y. 1991).
[35] *Id.* at 351.

is a matter of particular concern in light of the regulations' clear statement that agencies should account for the impact of 'reasonably foreseeable future actions.'"[36]

Based on this authority, in the case at hand, FERC's consideration of the cumulative impacts of the Project must take into account not only the cumulative impacts resulting directly and indirectly from the proposed project, but also the cumulative impacts of all past, present, and reasonably foreseeable natural gas development around the project.

The present draft EIS fails to adequately address a number of cumulative impacts, including the impacts of this and similar projects and Marcellus Shale development on air quality, climate change, and habitat destruction.

A. Background on Emissions from Natural Gas Activities

The cumulative impact of natural gas operations in the Marcellus Shale on air quality is potentially enormous. To appreciate the significance of these impacts, some context and background on natural gas development might be helpful.

The production, processing, transmission, and distribution of natural gas has significant effects on air quality because at each stage of production and delivery natural gas operations result in the release of significant quantities of nitrogen oxides ("NO_x"), volatile organic compounds ("VOCs"), hazardous air pollutants ("HAPs"), and greenhouse gases.[37] Natural gas pipelines in particular produce fugitive emissions of methane and hydrocarbons through "[l]eaks from pipeline networks, from microscopic holes, corrosion, welds and other connections, as well as from compressor intake and outlet seals, compressor rod packing, blow and purge operations, pipeline pigging, and from the large number of pneumatic devices on the pipeline network . . . ."[38] A survey of the emissions from natural gas activities in Texas's Barnett Shale estimates that fugitive emissions from transmission account for 35% of total fugitive emissions from natural gas activities, or 0.49% of gross production.[39] Compressor stations, such as the proposed Kidder Compressor Station expand and increase the throughput of, also generate fugitive emissions of VOCs, HAPs, and methane and emit NO_x and carbon dioxide ("CO_2") from fuel combustion.[40]

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[36] *Id.* (citing 40 C.F.R. §§ 1508.6, 1508.27(b)(7)).

[37] *See* Al Armendariz*, Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements*, 24 (2009) (hereinafter *Armendariz Report*).

[38] *Id.* at 7.

[39] *Id.* at 20.

[40] *Id.* at 21.

These pollutants affect air quality—and therefore human health—in a variety of ways. Both NO_x and VOCs are precursors of, and therefore contribute to the formation of, ozone.[41] Ozone exposure can lead to coughing, chest pain, and throat irritation.[42] It also worsens bronchitis, emphysema, and asthma, and can reduce lung function.[43] NO_x also contributes to the formation of fine particulate matter ("PM2.5").[44] Fine particulate matter is linked to increased heart attacks, aggravated asthma and decreased lung function, and for people with heart or lung diseases, premature death.[45] The most common HAPs associated with natural gas are n-hexane and the "BTEX compounds" benzene, toluene, ethylbenzene, and xylenes.[46] Benzene is a known human carcinogen, and formaldehyde, which is also emitted from natural gas operations, is a probable human carcinogen.[47] Methane is a potent greenhouse gas, which EPA estimates to have more than twenty times the global warming potential of CO_2.[48] Other estimates place the impact significantly higher; for example, a 2011 study placed the global warming potential of methane at between 33 and 105 times higher than CO_2, depending on the timeframe studied.[49] A recent study published in the journal Climatic Change Letters estimated that between 3.6 and 7.9% of the total methane produced by a given well drilled into a shale formation for hydraulic fracturing over the course of its lifetime will escape into the atmosphere.[50]

A 2009 report prepared by Dr. Al Armendariz of Southern Methodist University gives a sense of the sheer volume of air pollutants that are generated by natural gas activities. The survey found that total emissions of the ozone precursors NO_x and VOC that resulted from natural gas activities in the five-county region surrounding Dallas-Fort Worth in any given time period likely exceeded the emissions of those pollutants from motor vehicles in the same region during the same time period.[51] Similarly, emissions of GHGs, primarily CO_2 and

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[41] U.S. EPA, *Ozone – Good Up High Bad Nearby*, (2003), *available at* http://www.epa.gov/oar/oaqps/gooduphigh/ozone.pdf.

[42] *Id*.

[43] *Id.*

[44] U.S. EPA, *Nitrogen Dioxide*, *available at* http://www.epa.gov/air/nitrogenoxides/.

[45] U.S. EPA, *Particulate Matter (PM)*, *available at* http://www.epa.gov/pm/health.html.

[46] Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 76 Fed. Reg. 52,738, 52,745 (Aug. 23, 2011).

[47] *Id.* at 52,791.

[48] U.S. EPA, *Methane Emissions*, *available at* http://epa.gov/climatechange/ghgemissions/gases/ch4.html.

[49] Robert W. Howarth, Renee Santoro, Anthony Ingraffea, *Methane and the Greenhouse-Gas Footprint of Natural Gas from Shale Formations*, Climatic Change, 7 (2011), *available at* http://www.sustainablefuture.cornell.edu/news/attachments/Howarth-EtAl-2011.pdf.

[50] *Id*.

[51] Armendariz Report, *supra* note 1, at 1.

methane, were equivalent to those of two 750 MW coal-fired power plants.[52] The equivalent figures for the Marcellus Shale, which represents 55% of technically recoverable natural gas in the United States compared to Barnett Shale's 6%, will dwarf these.[53]

Despite the gravity of these impacts, and the undeniable fact that PennEast will contribute to them if it proceeds, FERC has not provided a meaningful analysis of the air quality and climate change impacts of Marcellus Shale development.

B. The cumulative impacts analysis must include impacts on air quality and Climate change from natural gas development in the Marcellus Shale.

FERC makes multiple attempts in the draft EIS to justify its decision not discuss the greater impacts of Marcellus Shale development. None are persuasive.

FERC first asserts that facilities associated with natural gas production are outside of the scope of the EIS because they are not within FERC's jurisdiction.[54] This contravenes the very definition of cumulative impacts, which, as mentioned above much include actions "*regardless* of what agency (Federal or non-Federal) or person undertakes such other actions."[55] The fact that some of the infrastructure associated with gas development and the PennEast project are outside of FERC jurisdiction has no bearing on whether they must be included in the draft EIS.

FERC next claims that impacts that result from additional shale gas development are neither reasonably foreseeable nor properly regarded as effects of the project. [56] This is also an untenable position. Development of the Marcellus shale is an ongoing process, without which the PennEast pipeline would not be viable. "Growth-inducing effects" are expressly included in the definition of "indirect impacts,"[57] and therefore are to be considered in the EIS. To the extent FERC tries to evade analysis by drawing a temporal distinction between development and transmission, arguing that the PennEast project will transport gas from existing infrastructure or development that has already been permitted, it again ignores the definition of cumulative impacts, which includes "past, present, and reasonably foreseeable" actions. The draft EIS mentions at least four times that the PennEast project is intended to bring gas from the Marcellus Shale to Pennsylvania, New Jersey, and neighboring states. Making Marcellus

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[52] *Id.*

[53] U.S. EIA, *Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays*, 4 (2011), *available at* ftp://ftp.eia.doe.gov/natgas/usshaleplays.pdf.

[54] Draft EIS 1-17

[55] 40 C.F.R. § 1508.7 (emphasis added).

[56] Draft EIS 1-18

[57] 40 C.F.R. § 1508.8(b); *see also Friends of the Earth, Inc. v. U.S. Army Corps of Engineers*, 109 F.Supp.2d 30, 41 (D.D.C. 2000) (holding that, when a project proposed the building of three floating casinos, "increased growth in the area is the only reasonable prediction of what will occur if the casinos are built" and that the Army Corps of Engineers must consider the growth-inducing effects of the proposed casinos).

shale gas available to consumers is hailed as a benefit of the project, as it would decrease the need to bring in fuel from other sources and places, such as the Gulf Coast. It is disingenuous to on one hand tout the benefits of increasing access to Marcellus shale as a purpose of the project while on the other hand denying the project is related to the ongoing development of the Marcellus shale gas.

Neither can discussion of Marcellus shale development be avoided by arguing that the details of development are unknown.[58] In analyzing the impacts of future natural gas activity in the Marcellus Shale, FERC must engage in "reasonable forecasting."[59] Projects "need not be finalized before they are reasonably foreseeable."[60] Thus, the fact that the precise locations and volumes of future natural gas operations cannot yet be identified does not excuse FERC from this obligation. Estimates prepared by other governmental entities may inform these forecasts. [61] New York State's Revised Draft Supplemental Generic Environmental Impact Statement ("NYS SGEIS"), for instance, provides scenarios with varying estimates of the number of wells likely to be drilled over 30 years of development.[62] This and other available reports should be incorporated into the analysis in order to arrive at an estimate of the air quality effects likely to cause cumulative impacts with the Project.

Because FERC has refused to consider the impacts associated with development and production of Marcellus shale, the discussions of cumulative impacts on air quality and climate change that are included in the draft EIS are incomplete.

C. The analysis of cumulative impacts on air quality is incomplete.

Even within the limited scope of cumulative impact analysis FERC has set out to undertake, it has failed to provide a full discussion of relevant issues pertaining to air quality. FERC

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[58] "An overall increase in production of shale gas may occur for a variety of reasons, but the location and subsequent production activity is unknown and too speculative to assume based on the interconnected interstate natural gas pipeline system. Accordingly, the factors necessary for a meaningful analysis of when, where, and how shale gas development would occur are unknown at this time. It is simply impractical for this EIS to consider impacts associated with additional shale gas development in separate geographic areas than the proposed Project because cumulative impacts resulting from the Project must, under CEQ regulations, be meaningfully analyzed by this Commission." (Draft EIS 1-18)

[59] *N. Plains Res. Council v. Surface Transp. Bd.*, 668 F. 3d 1067, 1079 (9th Cir. 2011) (quoting *Selkirk Conservation Alliance v. Forsgren*, 336 F.3d 944, 962 (9th Cir. 2003)).

[60] 668 F. 3d at 1078.

[61] *See id.* at 1079 (Surface Transportation Board could have based its forecasts on programmatic documents and data available from the state).

[62] New York State Department of Environmental Conservation, *Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program* ("*NYS SGEIS*"), at 6-208, 6-209 (Sept. 2011), *available at* http://www.dec.ny.gov/energy/75370.html.

identifies over thirty past, present, and reasonably foreseeable projects that is asserts it has evaluated for cumulative impacts.[63] The operational or ongoing emissions contributions of these projects are not evaluated at all. Instead, the draft EIS focuses on construction emissions, which it summarily dismisses as temporary, and mentions without further discussion that certain projects would have long-term air and noise impacts. [64] Cumulative emissions and impacts from construction and operation of projects are neither defined nor quantified, much less weighed and considered. FERC is well aware that this is unacceptable, as the draft EIS itself states that "cumulative impacts resulting from the Project must, under CEQ regulations, be meaningfully analyzed by this Commission."[65] By no measure does the discussion in the draft EIS on cumulative air quality and noise impacts amount to a meaningful analysis.

D. **The cumulative impacts analysis must include impacts on climate change from natural gas development in the Marcellus Shale and full discussion of the relationship between Project impacts and the impacts of climate change.**

The Council on Environmental Quality has stated that "[c]limate change is a fundamental environmental issue, and its effects fall squarely within NEPA's purview."[66] The EPA has recommended that greenhouse gas emissions from development and production of natural gas be considered along with emissions associated with end use of gas. [67]FERC has ignored this recommendation in regard to upstream development, relying instead on its own previous finding that while upstream development and production of natural gas might be reasonably foreseeable, the potential GHG emissions from upstream production are not.[68] This familiar argument amounts to willful blindness and cannot stand.

Tools to quantify greenhouse gas emissions are widely available, already in broad use, and agencies are expected to employ them when assessing environmental impacts.[69] Where tools, methodologies, or data inputs are not reasonably available to quantify greenhouse gas emissions, agencies are to provide a qualitative analysis of greenhouse gas emissions and an

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[63] Draft EIS 4-266
[64] Draft EIS 4-283
[65] Draft EIS 1-18

[66] Page 2, August 1,Final Guidance for Federal Departments and Agencies on Consideration of Greenhouse Gas Emissions and the Effects of Climate Change in National Environmental Policy Act Reviews
Page 2, December 2014, Revised Draft Comment- CEQ

[67] Draft EIS 4-285.
[68] Draft EIS 4-285.

[69] Page 12, August 1,Final Guidance for Federal Departments and Agencies on Consideration of Greenhouse Gas Emissions and the Effects of Climate Change in National Environmental Policy Act Reviews; Page 15 Revised Draft Comment-CEQ

explanation of why a quantitative approach was not warranted.[70] Here FERC makes no attempt to utilize available tools to quantify emissions associated with upstream development and production. It also fails to provide a qualitative analysis of these emissions or rationale for not using quantitative methods. FERC does provide estimates of CO_2 emissions associated with construction and operation of the project as well as end use of the natural gas, but these numbers hang bare in the draft EIS without explanation, context, or evaluation. Mere disclosure does not satisfy NEPA.[71]

Similarly, FERC acknowledges several impacts of climate change, and then without any analysis, asserts these impacts are not expected to exacerbate impacts of the Project. The absence of any support for FERC's conclusion on this point runs afoul of the Supreme Court's directive that "the agency must examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made."[72] In the case of at least two of the delineated climate impacts, FERC's conclusion seems to be directly contradicted within the draft EIS itself. Increased stress on native vegetation due to spread of invasive species is identified as an impact of climate change.[73] Spread of invasive species is also identified as a consequence of the vegetation disturbance that results from clearing right-of-ways necessary to build and maintain the Project.[74] Climate change is projected to lead to increases in carrier habitat and human exposure to vector-borne diseases such as Lyme disease, West Nile, and Zika virus.[75] The clearing of right-of-ways for linear projects such as the PennEast pipeline also results in edge effects, diminishing deep forest, and increasing habitat for species like white tailed deer which flourish in edge environments and can serve as vectors for tick-borne diseases such as Lyme disease.[76] Especially in light of these discrepancies, a careful analysis of the relationship between the effects of climate change and project impacts is needed.

FERC is fully aware of the significance of climate change.[77] In a revised draft EIS, the impacts of this project on climate change, including cumulative impacts from upstream and downstream emissions, and the relationship between project impacts and the effects of climate change must be evaluated thoroughly.

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[70] Id. at 13
[71] 40 C.F.R 1502.1 ("An environmental impact statement is more than a disclosure document.")
[72] *Motor Vehicle Mfrs. Ass'n of the U.S., Inc. v. State Farm Mut. Auto Ins.*, 463 U.S. 29, 43 (1983).
[73] Draft EIS 4-286
[74] Draft EIS 4-280
[75] Draft EIS 4-286
[76] Draft EIS 4-280
[77] FERC references the findings of the Intergovernmental Panel on Climate Change in the draft EIS. *See,* draft EIS 4-283.

E. Cumulative impacts of forest fragmentation have been acknowledged but not evaluated.

One of the most significant cumulative environmental impacts that pipelines and other natural gas infrastructure have is forest fragmentation. It is a long-recognized principle of ecology that clearing a section of forested land to make way for human activity—whether it be a pipeline, a road, a farm, or a housing development—has significant impacts on the surrounding area and the species that live in it that go far beyond simply the acres actually cleared. This process, known as forest fragmentation, is defined by the United States Geological Survey as occurring "when large areas of natural landscapes are intersected and subdivided by other, usually anthropogenic, land uses leaving smaller patches to serve as habitat for various species."[78]

Fragmentation divides previously contiguous forest into "core" forest and "edge" forest.[79] Edge forest is that forest that is 300 feet or less from the new border that has been created, while core forest is the forest that remains at least 300 feet from any edge.[80] Dividing a forest with a pipeline increases the ratio of edge forest to core forest and this leads to what are referred to as "edge effects."[81] Edge forest is a very different habitat from core forest. A new edge exposes forest to different levels of light, wind, and humidity, as well as to different predators.[82] It also allows the growth of weeds and other invasive species, and changes the distribution of plant species.[83] All of these changes alter the structure of the habitat and change the types of species it can support.[84] A new edge also reduces the amount of core forest that remains. Every expansion of edge forest eliminates many square feet of core forest area. A larger core forest can support a greater variety of species, and there are some species that only thrive in core forests.[85] Elimination of core forest can therefore lead to fewer species with lower populations, which are therefore much more susceptible to extinction.[86]

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[78] E. T. SLONECKER ET AL., U.S. GEOLOGICAL SURVEY., LANDSCAPE CONSEQUENCES OF NATURAL GAS EXTRACTION IN BRADFORD AND WASHINGTON COUNTIES, PENNSYLVANIA, 2004–2010 9 (2012), available at http://pubs.usgs.gov/of/2012/1154/of2012-1154.pdf (cited in Kelsey Eggert, *Speaking for the Trees: Preventing Forest Fragmentation in Pennsylvania's Marcellus Shale Region Through Pipeline Siting*, Vermont J. Envt'l L., Vol. 17, 372, 376 n. 24).

[79] Kelsey Eggert, *Speaking for the Trees: Preventing Forest Fragmentation in Pennsylvania's Marcellus Shale Region Through Pipeline Siting*, Vermont J. Envt'l L., Vol. 17, 372, 376.

[80] *Id.*
[81] *Id.*
[82] *Id.*
[83] *Id.*
[84] *Id.*
[85] *Id.*
[86] *Id.*

The draft EIS acknowledges that the Project and other pipeline development will increase fragmentation:

> Edge effects, which would be permanent due to permanent vegetation removal for some projects, and the necessity of maintaining the rights-of-way of utility projects clear of forest vegetation, would result in permanent cumulative impacts on habitat. A number of nearby linear projects, with pipelines such as the Atlantic Sunrise Pipeline, the Leidy Southside Expansion, the MARC II Pipeline, and the Susquehanna-Roseland Project, could contribute to these cumulative impacts.[87]

The serious deficiency of FERC's cumulative impacts analysis with respect to forest fragmentation is that, although the draft EIS clearly acknowledges the problem, FERC makes no attempt to quantify or assess the significance of the problem.[88] Failing to consider the cumulative forest fragmentation impacts of projects because they were or will be constructed at a different time than PennEast ignores the fundamental problem caused by forest fragmentation in the first place: it changes the habitat, its function, and the species it can support for decades or longer, particularly when rights of way are actively maintained i.e. cleared by pipeline companies. The fact that a project may have been constructed even several years ago in no way diminishes the cumulative forest fragmentation it may create if it impacts the same region impacted by the PennEast project. FERC, despite being well aware of this problem, has failed to take this into account in any meaningful way.

Any suggestion that it is not possible to quantify and directly analyze the cumulative effects of vegetation removal and forest fragmentation is simply wrong. CNA, a non-profit research and data analysis firm, has released a report funded by the Clean Air Council in which it determined the total acreage within the the Delaware River Basin that has been or will be cumulatively cleared by the major pipeline projects that go through that watershed or are proposed to.[89] Using GIS mapping technology, CNA was able to determine how much land cover of various types—forest, wetland, grassland, etc.—in total was or would be disturbed by these pipelines. CNA also determined that certain areas of the watershed, particularly Carbon, Northampton, and Chester Counties in Pennsylvania, and Hunterdon County in New Jersey were having their forests especially heavily impacted by pipeline development.[90] CNA was also able to analyze impacts on forested lands on a sub-watershed basis, finding the most significant

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[87] Draft EIS 4-280

[88] *See, e,g.*, Draft EIS at 4-276 ("However, the cleared rights-of-way associated with these actions would contribute to the long-term cumulative loss and fragmentation of forestland and associated wildlife habitat.")

[89] Lars Hansen and Steven Habicht, *Cumulative Land Cover Impacts of Proposed Transmission Pipelines in the Delaware River Basin*, CNA, May 2016, attached as Exhibit B.

[90] *See id.* at 25, Figure 10.

impacts in the Lehigh and Middle Delaware subbasins.[91] FERC could and should undertake a similar analysis before it approves the PennEast project. It is eminently possible for FERC to directly and quantitatively assess the cumulative impacts of vegetation removal from the PennEast project and other development in the areas surrounding the PennEast route in terms of forest fragmentation, as well as elimination or conversion of wetlands, stream crossings, and other impacts. Such an analysis would allow FERC to understand in quantitative terms how truly significant those cumulative impacts are. It would also allow FERC to identify areas along the proposed route, as CNA did for the Delaware River Basin, that are being particularly hard hit by the cumulative impacts of such development.

3. Analysis of the Kidder Compressor Station and its impact on air quality is incomplete.

The area in the immediate vicinity of the proposed Kidder Compressor Station has not been fully or accurately described in the draft EIS, making it impossible to determine the impacts of the facility. The maps and analysis of the Kidder Compressor Station construction site provided in the draft EIS neglect to mention a lake that is approximately a half mile long and located within 2000 feet of the proposed compressor station site.[92] PennEast's map does disclose another nearby body of water, Mosey Wood Pond, but FERC glosses over its significance. Mosey Wood Pond receives a single mention in the draft EIS, in a table where it is a listed as a "park."[93] Mosey Wood Pond is, in fact the heart of Camp Mosey Wood, an active Girl Scout camp with programming and outdoor recreation and education for children nearly year round.[94] In summer, children camp for a week or more at a time in platform tents, many of which are located closer to the proposed compressor station and the pipeline route than the pond itself.[95] Children staying in these tents and participating in the various outdoor activities the camp offers would be particularly vulnerable to the impacts of blowdowns.

Blowdowns are a regular occurrence at compressor stations, with the average blowdown emitting around 15 Mcf of pipeline gas into the atmosphere onsite. These blowdowns emit not only natural gas, but numerous hazardous air pollutants for which there are no NAAQS, and which are associated with illness in neighbors to the stations.[96] Neighbors living within 4000 feet of compressor stations have reported a variety of ailments, including sore throats, sinus problems, and headaches, with incidence of these ailments increasing as distance from a compressor station decreases.[97] The fact that compressor stations are subject

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[91] *Id.*
[92] Draft EIS, Appendix B, Facility Maps
[93] Draft EIS Table G-18
[94] See http://www.gsep.org/events/; *see also,* http://www.gsep.org/wp-content/uploads/2015/02/Mosey-Wood.pdf
[95] *Id.*
[96] Southwest Pennsylvania Environmental Health Project, Summary on Compressor Stations and Health Impacts, February 24, 2015, attached as Exhibit C.
[97] *Id.*

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to the National Emission Standards for Hazardous Air Pollutants does not change the fact that the Kidder Compressor Station, like other compressor stations, is very likely to produce quantifiable emissions at levels that are known to harm human health and the environment. This is ignored in the draft EIS.

A complete analysis of the impacts of the Kidder Compressor Station must start with an accurate and complete assessment of the area, including nearby residences, businesses, and outdoor recreation areas. The discussion of air quality impacts must identify and discuss the health impacts themselves, not just rely on PennEast's projections in relation to regulatory thresholds. Without these very basic components, FERC cannot provide a meaningful analysis of impacts as required by NEPA.

Conclusion

Clean Air Council respectfully requests that FERC consider these comments. As it stands, the draft EIS is inadequate under NEPA and must be supplemented or redone before a final EIS can be issued and before a certificate can be granted. FERC'S duty as a regulatory agency conducting a NEPA review is not to accept the regulated entities' representations at face value, nor to be an advocate for the expansion of natural gas transmission facilities, but to take a hard look at the environmental consequences of the proposed action and do a real evaluation of alternatives. The public does not have the resources at its disposal that the industry does, and must rely on FERC's impartiality and expertise in doing that analysis. Please take these comments into consideration and uphold your duties under NEPA.

Sincerely,

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Joseph Otis Minott, Esq.
Executive Director, Clean Air Council

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Exhibit A

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Risks Associated With Natural Gas

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IEEFA.org

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Risks Associated With Natural Gas

Major utilities, pipeline companies and natural gas producers are proposing construction of two new natural gas pipelines into Virginia and North Carolina from the Marcellus and Utica shale region of West Virginia.

Developers of the Atlantic Coast Pipeline and the Mountain Valley Pipeline, which would cost a total of nearly $9 billion to complete, have applied to the Federal Energy Regulatory Commission for approval.

The pipelines are proposed to go into service in 2018. They would be part of a larger expansion of natural gas pipeline infrastructure from the Marcellus and Utica shale region in Appalachia that has been described by Moody's Investors Services as an "once-in-a-lifetime build-out cycle" driven by the recent boom in natural gas production.

Some participants have openly acknowledged the likelihood of overbuilding, as when Kelcy Warren, CEO of Energy Transfer Partners, said in an earnings call last year that overbuilding is part-and-parcel of the industry ("The pipeline business will overbuild until the end of time," Warren said).

This report shows how the Atlantic Coast and Mountain Valley pipelines are emblematic of the risks that such expansion creates for ratepayers, investors and landowners.

Among its conclusions:

- Pipelines out of the Marcellus and Utica region are being overbuilt.
- Overbuilding puts ratepayers at risk of paying for excess capacity, landowners at risk of sacrificing property to unnecessary projects, and investors at risk of loss if shipping contracts are not renewed and pipelines are underused.
- The Federal Energy Regulatory Commission facilitates overbuilding. The high rates of return on equity that FERC grants to pipeline companies (allowable rates of up to 14%), along with the lack of a comprehensive planning process for natural gas infrastructure, attracts more capital into pipeline development than is necessary.
- FERC's approach to assessing the need for such projects is insufficient.
- Industry leaders recognize and acknowledge that current expansion plans will likely result in overbuilding.

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- The arguments for the Atlantic Coast Pipeline have not been adequately scrutinized. While the pipeline developers have asserted that some of the gas supplied is needed by Dominion Resources for its new Brunswick and Greensville natural gas plants, Dominion has told the Virginia State Corporation Commission that it can supply those plants through the existing Transco pipeline.
- While ratepayers of the utilities (largely Duke Energy and Dominion Virginia Electric and Power) that have contracted to ship gas through the Atlantic Coast Pipeline would be burdened with the costs of building the pipeline (which would include a profit to the developers, largely Duke and Dominion), they will probably not realize the economic benefits promised by the developers.
- Communities along the Mountain Valley Pipeline face the risk that EQT Corporation (which owns the largest stake in that pipeline and has contracted for the largest volume of capacity on the pipeline) will continue to be harmed financially by weak natural gas prices and will not be a long-term, stable partner for these communities.

This report notes also that much of the $9 billion costs of the projects—aside from the costs embedded in the price of any natural gas that is exported—would ultimately be either added to the price consumers pay for natural gas or absorbed as a loss to project investors.

And it points out that regulators have not considered whether these pipelines are the best use of ratepayer dollars. None of the economic interests within the natural gas industry have any incentive to seriously consider whether alternatives to natural gas - energy efficiency, renewable energy or other forms of power generation - may be cheaper.

Given all of these circumstances, IEEFA recommends the following:

- That the applications for the Atlantic Coast and Mountain Valley pipelines be suspended until a regional planning process can be developed for pipeline infrastructure;
- That FERC lower the returns on equity granted to pipeline developers; and
- That an investigation be conducted into the relatively high failure rate of new pipelines.

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Risks Associated With Natural Gas

The Federal Energy Regulatory Commission is considering applications for construction of two major natural gas pipelines that would run from West Virginia into North Carolina and Virginia: the Atlantic Coast Pipeline and the Mountain Valley Pipeline.

These pipelines, which together would stretch for approximately 850 miles, are being contemplated during a time of major natural gas infrastructure expansion in the U.S.

In October 2014, Moody's Investors Service characterized the proposed pipeline build-out from the Marcellus and Utica shale region as "the start of a once-in-a-lifetime build-out cycle."[1]

This report examines the risks these projects pose to consumers, investors, and communities along the proposed routes.

Part 1 of the report describes the rapid buildout of Marcellus and Utica pipeline infrastructure in order to place the Atlantic Coast and Mountain Valley pipelines in the context of the larger expansion of pipeline infrastructure. Part 2 considers specific risks associated with the proposed Atlantic Coast and Mountain Valley pipelines.

Risks Associated With Natural Gas
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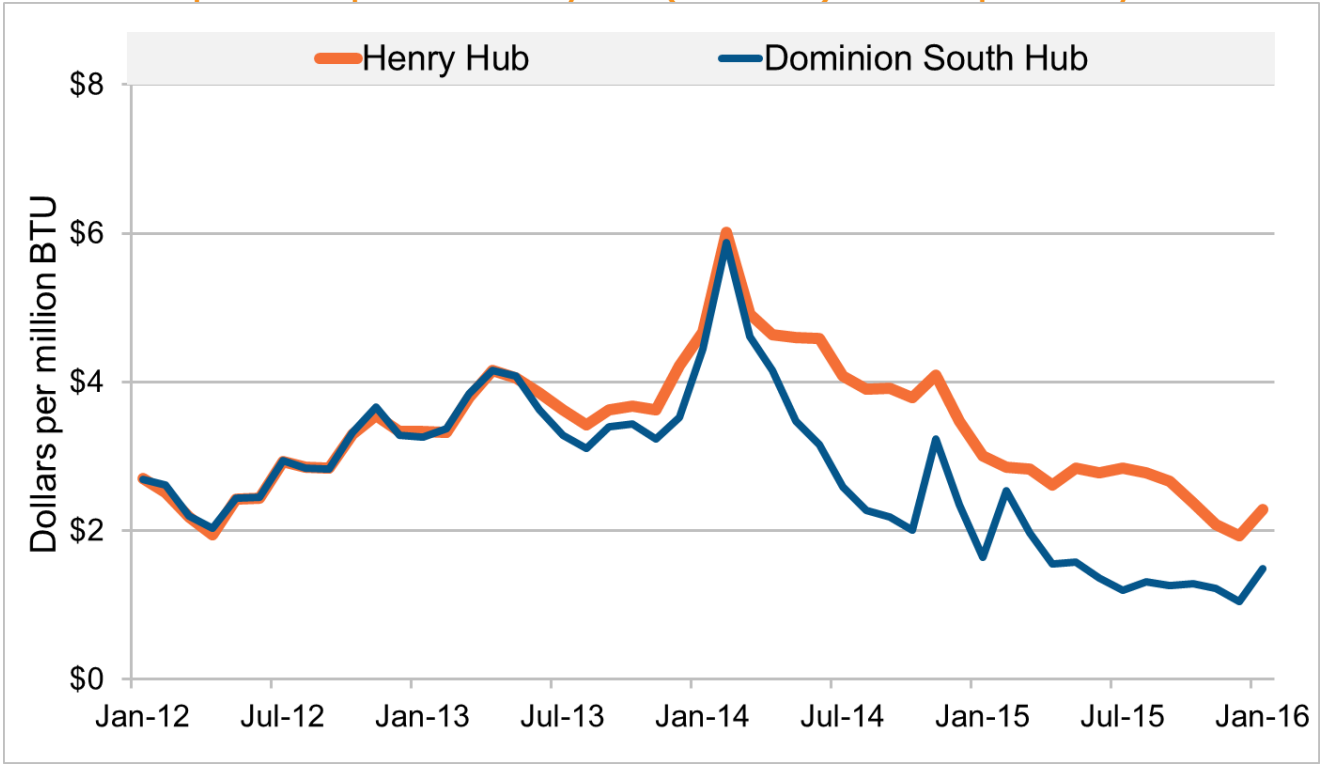
Risks Associated With Natural Gas

The boom in natural gas pipeline construction associated with the Marcellus and Utica shale region is driven fundamentally by the low price of shale gas and the desire on the part of developers to transport that gas to higher-priced markets, perhaps even to export markets. The following graph shows prices since January 2012 at the Dominion South Hub in southwestern Pennsylvania versus those at the Henry Hub in Louisiana. Henry Hub prices are often used as the benchmark for natural gas prices in the U.S. The Henry Hub has historically been where the largest volumes of gas have traded. In recent years, larger or comparable volumes have been

[1] "Shale-Fueled Inflection Point for Pipeline Operators; Offshore Rig Oversupply to Persist," Moody's Investors Service, October 15, 2014.

traded at the Dominion South Hub, reflecting the upsurge in natural gas production in the Marcellus and Utica regions.[2] The price of natural gas at the Dominion South Hub has recently been very low, averaging $1.50 per MMBTU in 2015 while Henry Hub prices averaged well over $2 per MMBTU. And 2015 was no anomaly. Over the past three years, prices at the Dominion South Hub have decoupled from Henry Hub prices, remaining consistently lower.

Figure 1. Natural gas prices at the Dominion South Hub (southwestern Pennsylvania) have decoupled from prices at Henry Hub (Louisiana) over the past few years.



Source: SNL Financial

The low price of Marcellus natural gas is partially a factor of limited takeaway capacity (the gas is less valuable if it cannot be tapped) for moving this natural gas to market. As a result, numerous proposals have been made to build new pipelines to move this natural gas out of West Virginia, western Pennsylvania and Ohio.

The financial dynamics of the natural gas industry encourage overbuilding of natural gas pipelines, i.e. the construction of excess capacity. A weak regulatory process and a lack of coordinated planning for natural gas infrastructure facilitate this process.

The next several sections here explore the causes and consequences of overbuilding pipeline capacity.

[2] In 2012 and 2013, the volume of gas traded at the Dominion South Hub exceeded the volume traded at the Henry Hub. In 2014, 84,000 MMBTU were traded at the Dominion South Hub versus 90,000 at the Henry Hub, and in 2015, 60,000 MMBTU were traded at the Dominion South Hub versus 61,000 at the Henry Hub. (Source: SNL Financial)

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Various economic interests drive pipeline investment that tends toward building excess capacity. In the past, pipeline development in the U.S. has been done by a set of companies that specialize in the pipeline field, including Kinder Morgan, Columbia Pipeline Group and Williams Company. However, in recent years, electric and natural gas utilities, as well as natural gas producers, have begun to move into the natural gas pipeline business. All of these entities—traditional pipeline developers, utilities and producers—can have incentives to overbuild.

For example, current low natural gas prices in the Marcellus and Utica region are driving a race among natural gas pipeline companies that want to capitalize on low prices by building new pipeline capacity to higher-priced markets. An individual pipeline company acquires a competitive advantage if it can build a well-connected pipeline network that offers more flexibility and storage to customers; thus, pipeline companies competing to see who can build out the best networks the quickest.[3] This is likely to result in more pipelines being proposed than are actually needed to meet demand in those higher-priced markets.

Additionally, utilities—which have been attracted to the natural gas pipeline business because of its traditionally high returns and to further integrate their supply chains as electric power generation becomes increasingly reliant on natural gas—have an economic interest in building new lines. A regulated electric or gas utility that is purchasing natural gas for power generation or for use as a heating fuel passes the cost of its pipeline contracts, which include a FERC-approved profit for the pipeline developer, on to its customers.[4] If the regulated utility's parent company can build its own pipeline for use by its regulated subsidiary, it can capture this profit, giving a utility holding company an incentive to prioritize building its own pipeline rather than utilizing that of another company.[5] This structure also shifts some of the risk of

[3] Tyler Crowe, "5 Things Energy Transfer's Management Wants You to Know," The Motley Fool, September 10, 2015.

[4] Some utility holding companies are becoming involved in the natural gas pipeline business even though they do not own any power plants. In New England, regulated electric distribution utilities are proposing to enter into contracts for natural gas capacity on new pipelines in order to re-sell that capacity on the secondary market to natural gas power plants, with the goal of bringing down prices for natural gas generation. The costs or benefits of this transaction (the costs of long-term capacity contracts, net the revenues received from re-selling that capacity to generators) are to be passed on to the customers of the regulated distribution utilities. Some of the regulated utilities involved in these contracts are subsidiaries of holding companies, including National Grid and Eversource, that are investors in building the new pipelines. (Sources: M. Serreze, "National Grid seeks Massachusetts DPU approval of gas pipeline capacity contracts," MassLive, January 22, 2016; S. Sullivan, "Algonquin Gas introduces nearly 1-Bcf/d Access Northeast to FERC early review," SNL Financial, November 3, 2015;).

[5] State public utilities commissions often have a role in regulating contracts between regulated utilities and their affiliates (in this case, between the regulated utility and the affiliate that owns a share in the pipeline). State commissions also must ensure that the regulated utility acted prudently in sourcing its supply of natural gas. To our knowledge, no regulated utility has been denied cost recovery, in whole or in part, for a contract with an affiliated natural gas pipeline, but this is a potential risk to utilities in the future.

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pipeline development from the developer and its shareholders to the regulated utility's ratepayers.

Some upstream producers of natural gas, such as EQT Corporation, have also moved into the pipeline construction business. For such companies, investment in pipelines promises a relatively stable revenue stream compared to the volatility of the natural gas drilling business. EQT, for example, has taken advantage of investors' willingness to fund pipeline development by creating an EQT-controlled master limited partnership (EQT Midstream), which has been able to raise equity through public offerings both for new pipeline projects and for buying gathering and processing infrastructure formerly owned by EQT, leaving EQT in a much better cash position than many other drillers. Such short-term balance sheet considerations for a company like EQT do not translate into rational planning of long-term infrastructure. These dynamics will be explored in more detail in Part 2, Section B below.

None of the economic interests within the natural gas industry have any incentive to seriously consider whether alternatives to natural gas— energy efficiency, renewable energy or other forms of power generation—may be cheaper. There is little discussion of how long-term natural gas demand will evolve over the lifetime of a proposed pipeline as alternatives become increasingly cost-effective and widespread.

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A coordinated planning process for natural gas infrastructure could serve as a check on the tendency of individual pipeline developers to overbuild.

But the U.S. has no overarching national or regional planning process for natural gas infrastructure development. This planning void contrasts sharply with established planning processes for electricity transmission lines, interstate highways and many other types of infrastructure. Electricity transmission in states with deregulated electricity markets, for instance, is overseen by Regional Transmission Organizations (regulated by the Federal Energy Regulatory Commission[6]) that have planning processes to determine whether proposed new transmission lines are needed and whether there are more cost-effective alternatives to building new lines. While electric transmission lines ultimately must be approved by FERC and by state public utilities commissions, the RTO-level transmission planning process has informed decision making and sometimes led to the cancellation of proposed new electric transmission lines that are shown to be unnecessary.[7]

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[6] The Federal Energy Regulatory Commission, FERC, regulates electric transmission under the Federal Power Act and natural gas pipeline infrastructure under the Natural Gas Act. The Federal Power Act, as amended by the Energy Policy Act of 2005, has explicit provisions for transmission planning (see Federal Power Act Section 217(b)(4)). FERC Orders 890 and 890-A relied on this authority in "mandating coordinated, open and transparent transmission planning on a local and regional level." These orders require transmission providers to incorporate nine principles into their planning process, including "coordination" with customers and neighboring transmission providers, "regional participation" (coordination with interconnected systems) and "economic planning studies." (*See*: Lawrence Greenfield, "An Overview of the Federal Energy Regulatory Commission and Federal Regulation of Public Utilities in the United States," Office of the General Counsel, Federal Energy Regulatory Commission, December 2010).

[7] For example, PJM's Regional Transmission Expansion Plan process allowed the Virginia State Corporation Commission to see that the PATH power line proposed through West Virginia, Virginia and Maryland was unnecessary because the reliability

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No such planning process exists for the build-out of natural gas pipeline infrastructure. While FERC must approve the construction of new pipelines, it does not conduct any long-term assessment of regional natural gas demand in assessing the need for new pipelines.

Instead, FERC primarily relies on whether a pipeline developer has been able to recruit enough companies to contract for capacity on the line. If a pipeline is fully or near fully subscribed, FERC considers this strong evidence that the pipeline is necessary.

This approach by FERC is highly likely to result in excess capacity that will be underutilized. For example, in situations in which a pipeline developer contracts with an affiliate company to ship gas through a new pipeline, this is strong evidence that it is doing so because of the financial advantage to the parent company from building the pipeline, but not necessarily that there is a need for the pipeline. As described in the previous section, the private financial interests of individual pipeline developers do not necessarily align with the public interest.

Proposed Proposed

Proposed

Not only do the dynamics of the natural gas and pipeline industries tend to favor building excess capacity, but federal regulatory policy toward pipelines does too.

FERC is in charge of regulating the rates that pipeline companies charge to shippers (the entities that are contracted to ship gas through pipelines). Pipeline rates are required to be cost-based, meaning that they must reflect the cost to the pipeline company of providing the service. This cost includes a return on equity (profit) to the pipeline company for the capital that it has invested in building the line.[8] Pipelines are financed partially with debt and partially with equity.

In theory, without FERC regulation, a pipeline company could take advantage of a shipper by charging exorbitant rates, because the shipper may have no other option for delivering gas. In order to prevent this, FERC sets the "recourse rate," which is the rate that a shipper is allowed to demand and receive. This prevents the pipeline company from gouging a shipper. Both the Atlantic Coast Pipeline and the Mountain Valley Pipeline have applied for recourse rates that include a return on equity of 14%. This is a relatively common request, and one that has been granted on many recent greenfield pipelines, including the Constitution

problems that PATH would solve could be solved less expensively through rebuilding existing transmission lines. (Sources: Virginia State Corporation Commission, "Hearing Examiner's Ruling," Case No. PUE-2010-00115, January 19, 2011; PATH Allegheny Virginia Transmission Corporation, "Motion to Withdraw Application," Case No. PUE-2010-00115, February 28, 2011).

[8] It is worth noting that, at least in the case of the Atlantic Coast pipeline, this "capital" includes more than the actual construction costs of the pipeline. The Atlantic Coast Pipeline is seeking to earn a return on landowner outreach, community and government meetings regarding the route, and preparation of regulatory filings.(See: Atlantic Coast Pipeline, LLC & Dominion Transmission, Inc., FERC Docket Nos. CP15-554-000 & CP15-555-000, Response to Data Request, December 15, 2015.)

Pipeline[9] approved in 2014, the Sierrita Gas Pipeline in 2014,[10] the Ruby Pipeline in 2011,[11] the Bison Pipeline in 2010[12] and the ETC Tiger Pipeline in 2010.[13]

A 14% return on equity is high relative to returns that one could expect to receive by investing capital elsewhere in the utility business. In 2014, the average return on equity granted by state public utilities commissions to investor-owned electric utilities was 9.92%.[14] And FERC has recently lowered its allowed return on equity for electric transmission companies in New England to a maximum of 11.74% and is expected to lower returns for transmission companies in the Midwest as well this year. [15]

FERC has provided little justification to support recourse rates that include a 14% return on equity for new pipelines. In comments opposing a 14% return on equity for the Atlantic Coast Pipeline, the North Carolina Utilities Commission (NCUC) noted that FERC has never required pipeline companies to provide much evidence to support such requests. Indeed, the only support the developers of the Atlantic Coast Pipeline provided to justify its request were citations to previous FERC orders granting 14% returns on equity for new pipelines, but those FERC orders themselves did not provide any justification for granting 14% returns. The NCUC stated that "[w]hile the NCUC recognizes that in the past the Commission has merely accepted recourse rates based on cases citing previous cases, application of that policy would appear to conflict with the unambiguous statutory requirement that a filing entity demonstrate that its filing, including the recourse rates, comports with the public convenience and necessity."[16]

In practice, most major contracts between pipelines and shippers are not based on recourse rates, but on negotiated rates. Because a pipeline company needs to prove to FERC that it has attracted customers to ship gas on its pipeline in order to obtain FERC approval to build the line, it needs to negotiate long-term contracts with shippers in advance of proposing the pipeline to FERC. So-called "anchor" or "foundation" shippers who agree to enter into these long-term (15- to 20-year) contracts are typically granted preferential rate treatment, i.e. with negotiated rates that are lower than the recourse rates.

Negotiated rates do not have to be approved by FERC, but they must be filed with FERC between 30 and 60 days before the pipeline is placed into service.[17] This means that the negotiated rates for the Atlantic Coast and Mountain Valley pipelines are not currently publicly available, so there is no way of knowing what return on equity is embedded in these negotiated rates.

Even though the return on equity embedded in the recourse rate is not necessarily what the pipeline earns, because the negotiated rate may be based on a different return on equity, the recourse rate still provides an important benchmark. Interruptible rates for non-firm pipeline

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[9] 149 FERC ¶ 61,199 (2014)
[10] 147 FERC ¶ 61,192 (2014)
[11] 136 FERC ¶ 61,054 (2011)
[12] 131 FERC ¶ 61,013 (2010)
[13] 131 FERC ¶ 61,010 (2010)
[14] Edison Electric Institute, "Industry Financial Performance," 2014, online at http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/finreview/Documents/FinancialReview_2014_02_IndustryFinPerf.pdf, accessed April 13, 2016.
[15] R. Walton"Breaking down FERC's recent, and pending, ROE decisions," Utility Dive, November 17, 2014; and J. O'Reilly, "RRA Focus on FERC – January 2016: Downward pressures on ROEs continues as FERC ALJ recommends significant reduction in MISO, new complaints filed against Duke in NC, SC," SNL Financial, January 15, 2016.
[16] FERC Docket No. CP15-554, "Comments in support of project and protest of proposed recourse rates of the North Carolina Utilities Commission," October 23, 2015.
[17] 133 FERC ¶ 61,220 (2010)

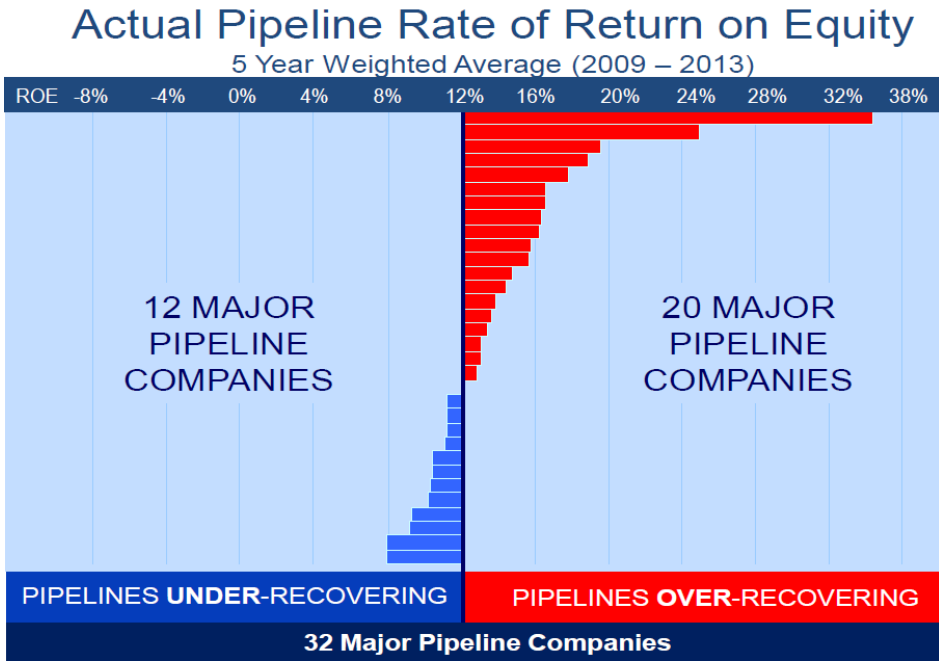
service are based on the recourse rates. And the rates of return embedded in the recourse rates define what is considered to be a reasonable return for pipeline companies, which is important for any entity seeking to file a complaint with FERC that a pipeline company is over-earning.

A pipeline's rates can be challenged by FERC Staff or by outside entities if the pipeline appears to be earning an excessive rate of return.[18] (Just because rates are set based on an expected return does not preclude the pipeline company from earning higher than that return, if it is able to reduce other costs). Such challenges are typically based on annual financial data that must be filed with FERC after a pipeline has been placed into service. While the FERC complaint process can result in new, lower rates being established, the excess earnings that the pipeline is found to have received in past years do not have to be refunded to customers.[19]

In practice, many pipelines appear to be earning higher returns than authorized in their recourse rates. A recent study from the National Gas Supply Association, an association of natural gas suppliers, producers and marketers, looked at the returns on equity from 2009-2013 of 32 major natural gas pipeline companies, comprising 75% of interstate natural gas market capacity. Fewer than 40% of the companies were earning returns on equity of 8-12%. The majority of companies earned returns on equity greater than 12%, with two of those companies earning returns on equity in excess of 24%.[20]

In short, the regulatory environment created by FERC encourages pipeline overbuild. The high returns on equity that pipelines are authorized to earn by FERC and the fact that, in practice, pipelines tend to earn even higher returns, mean that the pipeline business is an attractive place to invest capital. And because, as discussed previously, there is no planning process for natural gas pipeline infrastructure, there is a high likelihood that more capital will be attracted into pipeline construction than is actually needed.

Figure 2. The Majority of Major Pipeline Companies Earned Returns In Excess of 12% For 2009-2013.



Source: Natural Gas Supply Association

[18] For example, FERC opened an investigation into a Kinder Morgan pipeline in 2011 that FERC Staff estimated had earned a return on equity of 19.55% in 2010 and 18.51% in 2011. (Source: S. Sullivan, "WIC submits settlement to take care of FERC rate investigation," SNL Financial, June 25, 2013)

[19] American Public Gas Association, "Section 5," Online at http://www.apga.org/issues/issues-section-5, last accessed April 13, 2016.

[20] Pen Cankardes Ulrey, "Pipeline Cost Recovery Report: 32 Major Pipelines, 2009-2013," Natural Gas Supply Association (no date).

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Proposed Proposed Proposed Proposed Proposed Proposed Proposed

State regulatory commissions play a very limited role in regulating interstate natural gas pipelines.

Although regulations vary from state to state, state public service commissions often regulate contracts and transactions between regulated utilities and their affiliates. Thus, if a regulated utility seeks to enter into a contract for pipeline capacity with a corporate affiliate that is developing the pipeline, it may require approval from the commission to enter into the contract. In the case of the Atlantic Coast Pipeline, the North Carolina Public Utilities Commission has granted approval for Duke Energy Progress, Duke Energy Carolinas and Piedmont Natural Gas to become shippers on the pipeline. Dominion Virginia Electric and Power has not yet sought similar approval from the Virginia State Corporation Commission.

State regulatory commissions also have a role in approving the pass-through of the costs of pipeline contracts to the rates of regulated utility customers. The cost of shipping natural gas on a pipeline, including the return on equity for the pipeline company, is an operating cost for the end-use utility and is therefore a cost that is passed through to utility customers, as long as the state commission agrees that this cost has been prudently incurred.[21] A commission could disallow all or part of the costs paid pursuant to a natural gas contract if the commission finds that such costs were not prudently incurred (for example, if the utility knowingly contracted for too much capacity or failed to secure a lower-priced contract). The commission would have to find that the utility's decision at the time of entering into the contract was imprudent, not that the contract turned out to be expensive for ratepayers in hindsight.

Such a potential disallowance would of course occur after the pipeline has been placed into service. In the absence of affiliate contracts, utilities have no incentive not to enter into prudent contracts with third-party suppliers. The transaction structure in which a regulated utility contracts to ship gas on a pipeline developed by an affiliate company is a relatively recent development that tends to shift risk from shareholders to ratepayers. It is not yet clear whether state public utilities commissions will scrutinize pipeline capacity procured under such contracts more closely in rate-making.

Additionally, if a state commission believes that a pipeline is earning excessive returns, it can challenge the pipeline's rates at FERC (as described above) but it does not have authority to alter recourse or negotiated rates.

[21] For example, Dominion Virginia Electric and Power has entered into a contract for capacity on the Atlantic Coast Pipeline. That contract contains, embedded in it, a return on equity for the pipeline developer (in which Dominion Resources has an interest). The payments made pursuant to that contract are expenses that Dominion Virginia Electric and Power will be allowed to pass through to its ratepayers, as long as the Virginia State Corporation Commission agrees that those expenses were prudently incurred.

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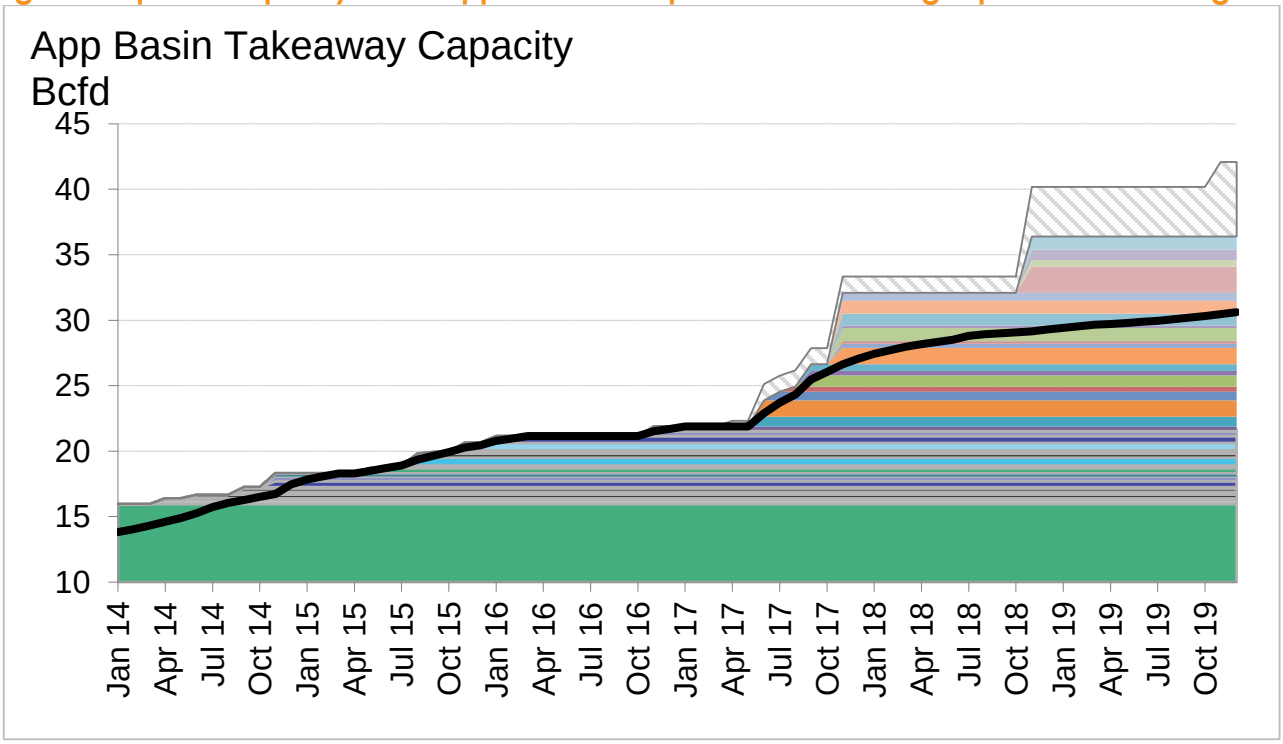
Thus, state regulatory commissions only play a role in approving the initial construction of a pipeline to extent that they are required to approve a regulated utility's decision to enter into a contract with an affiliate that is building the pipeline. The state regulatory commission's role in regulating the cost of natural gas contracts embedded in the rates of utility customers occurs after a pipeline has been constructed and therefore has little impact on the potential for overbuilding pipelines.

Proposed Proposed Proposed Proposed Proposed

Industry financial dynamics, coupled with favorable federal regulatory treatment, will likely result in excess pipeline capacity being built out of the Marcellus and Utica shale region. **The pipeline capacity being proposed exceeds the amount of natural gas likely to be produced from the Marcellus and Utica formations over the lifetime of the pipelines.** An October 2014 analysis by Moody's Investors Service stated that pipelines in various stages of development will transport an additional 27 billion cubic feet per day from the Marcellus and Utica region. This number dwarfs current production from the Marcellus and Utica (approximately 18 billion cubic feet per day).[22] The following graph from Bloomberg New Energy Finance shows that pipeline capacity out of the Marcellus and Utica will exceed expected production by early 2017.[23]

Figure 3. Pipeline capacity out of Appalachia is expected to exceed gas production starting in 2017.



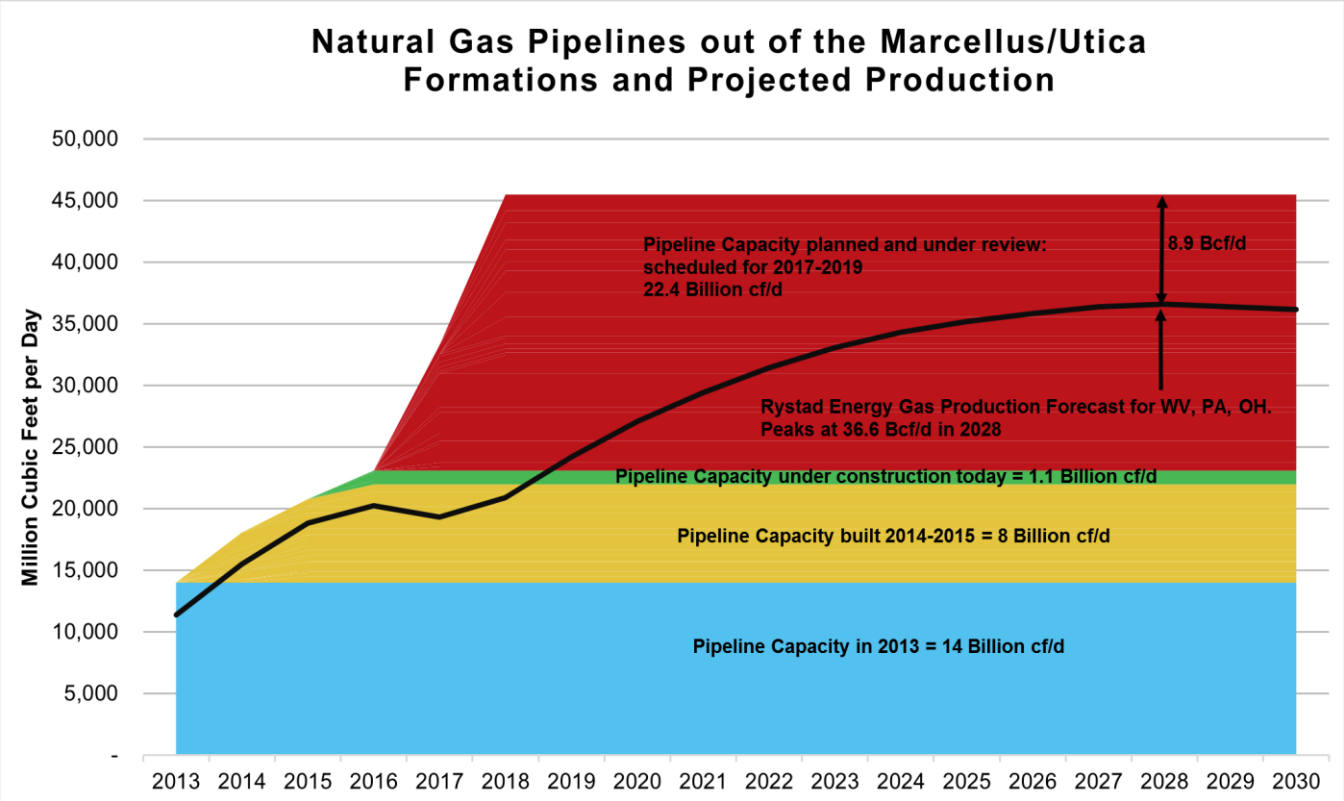
Source: Bloomberg New Energy Finance, 2016. The black line represents expected production and the bars represent planned capacity. Billion cubic feet per day (Bcfd).

[22] U.S. Energy Information Administration, "Utica Region: Drilling Productivity Report," April 2016, and U.S. Energy Information Administration, "Marcellus Region: Drilling Productivity Report," April 2016.

[23] Joanna Wu, "US Gas Insight: Midstream Madness," Bloomberg New Energy Finance, March 8, 2016.

Over the long term, as shown in the following chart from a forthcoming paper by Oil Change International, pipeline capacity is expected to exceed Marcellus and Utica production through 2030, with production peaking around 2028.[24]

Figure 4. Natural gas pipeline capacity is expected to exceed production through 2030. Production forecast from Rystad.



Source: Oil Change International, 2016

Industry leaders are well aware that the dynamics of the pipeline industry lend themselves towards overbuilding.

Kelcy Warren, CEO of Energy Transfer Partners (ETP), said as much in comment last year on the company's second quarter 2015 earnings call: "The pipeline business will overbuild until the end of time. I mean that's what competitive people do."[25] In a subsequent earnings call, he provided the specific example of the Barnett shale in Texas: "There is no question there are certain areas that are overbuilt. For example, we overbuilt in Barnett shale. The production peaked and it's now down."[26] Energy Transfer Partners would know. It is the largest transporter of

[24] Discrepancies between the timing and extent of capacity additions shown in Figures 3 and 4 may be attributable to (a) the fluidity of projects in early stages of development in terms of proposed capacity; and/or (b) differences in attempting to distinguish between pipelines that are expected to add new takeaway capacity versus provide greater connectivity between pipeline networks.

[25] Energy Transfer Partners 2nd quarter 2015 earnings call, August 6, 2015.

[26] Energy Transfer Partners 3rd quarter 2015 earnings call, November 5, 2015.

natural gas out of the Barnett shale of northeast Texas; ETP's pipeline capacity alone now exceeds the total 2015 natural gas production in the Barnett shale, which is down 24% from its peak in 2012.[27,28]

Southwestern Energy, a driller in the Fayetteville shale of northwest Arkansas and in Appalachia, predicts overbuilt pipeline capacity by 2018.[29] And Elie Atme, vice president for Marketing and Midstream Operations for Range Resources, one of the largest Appalachian shale drillers, has stated that Range expects that "the Appalachian Basin's takeaway capacity will be largely overbuilt by the 2016-2017 timeframe."[30]

In the meantime, existing natural gas pipeline capacity is going underutilized, even as companies propose new pipelines. A 2015 report by the Department of Energy found that from 1998 to 2013, existing pipelines in the U.S. had an average capacity utilization of 54%.[31,32]

As noted in a recent article in American Oil and Gas Reporter, new construction and potential overbuilding of pipelines may lead to existing pipelines losing shippers, "thus creating the irony of unused capacity at the same time new capacity is being constructed."[33]

Proposed Proposed

Proposed Proposed

Overbuilding of natural gas pipeline infrastructure poses risks to ratepayers, investors and communities along pipeline routes.

Excluding natural gas destined for export, the rates charged for shipping gas on pipelines are ultimately passed through to the consumers of the gas, largely customers of electric and natural gas utilities. That leaves ratepayers at risk of paying for unnecessary new capacity.

[27] Energy Transfer Partners, "Press Release: Energy Transfer Adds Vital Capacity out of the Barnett Shale," January 8, 2009.
[28] Texas Railroad Commission Production Data Query System, "Texas Barnett Shale Total Natural Gas Production 2000 through 2015," February 22, 2016. Online at: http://www.rrc.state.tx.us/media/22204/barnettshale_totalnaturalgas_day.pdf
[29] Southwestern Energy 2nd quarter 2015 earnings call, July 28, 2015.
[30] Kallanish Energy Daily News & Analysis, "Marcellus-Utica could soon be 'overpiped,'" February 1, 2016.
[31] U.S. Department of Energy, "Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector," February 2015.
[32] Existing pipelines in West Virginia, Virginia and North Carolina are even more underutilized. According to EIA data, average capacity utilization in 2014 for pipelines flowing out of West Virginia was 33%. Utilization of pipelines flowing into Virginia was 23% and, into North Carolina, 37%. (Source: U.S. Energy Information Administration, "International & Interstate Movements of Natural Gas By State," 2016 online at http://www.eia.gov/dnav/ng/ng_move_ist_a2dcu_nus_a.htm; U.S. Energy Information Administration, "U.S. State to State Capacity," online at http://www.eia.gov/naturalgas/pipelines/EIA-StatetoStateCapacity.xls).
[33] Tom Seng, "Resource Plays Spur Big Infrastructure Rebuild", American Oil and Gas Reporter, August 2013.

Overbuilding creates the risk for investors that a pipeline developer will be unable to renew its contract with shippers after the initial (typically 15- to 20-year) contracts expire. If a pipeline proves to be unnecessary, shippers may not want to renew their contracts. Because pipeline finances are structured so that the costs of the project are recovered over a period longer than the initial contract, investors lose out if the contracts cannot be renewed. This risk is greatly reduced if the shipper is a regulated utility affiliate of the developer.

Additionally, the boom in pipeline development is encouraging companies for whom pipeline development is not their core business to diversify into the sector. This poses its own risks for investors. Whether it is a supplier or utility-driven investment in natural gas pipelines, the companies involved are pursuing higher returns, based presumably on an assessment of their business models that point to a ceiling on the profitability of core business. For these companies, investing in a natural gas pipeline can look like an investment in an area with tightly drawn market adjacencies to their current core businesses, thus minimizing future risk. These investments outside the core can produce returns, but they can also produce pain.[34]

Landowners are at risk from having their land seized and potentially damaged for pipeline projects that are not needed. Additionally, landowners and communities along pipeline routes may be at risk of greater safety problems. As reported in SNL Financial, "the push to build new pipelines to transport abundant shale supplies appears to be having a materially adverse impact on pipeline safety." Data from the Pipeline Safety Trust shows that pipelines built in the 2010s are failing at a rate similar to the failure rate for pipelines constructed pre-1940 (see figure 5).[35] Though it is not clear the specific reasons for the high failure rate of the new pipelines, this data has led to speculation that the boom in construction of natural gas pipelines has led contractors to cut corners.[36]

[34] For example, FirstEnergy, an Ohio-based utility that owns many coal-fired power plants, bought into the Signal Peak coal mine in Montana in 2008, an investment related to, but outside of, FirstEnergy's core utility business. Signal Peak was seen as an attractive investment because it could feed FirstEnergy's own coal fleet and could sell coal into a growing export market. The investment has since floundered as the coal mining business entered a downturn. FirstEnergy has recently incurred a significant asset impairment on this mine (Source: M. Brown, "Signal Peak Owner Says the Mine is Worth Nothing," Billings Gazette, February 24, 2016).

[35] S. Smith, "As U.S. rushes to build gas lines, failure rate of new pipes has spiked," SNL Financial, September 9, 2015.

[36] Ibid.

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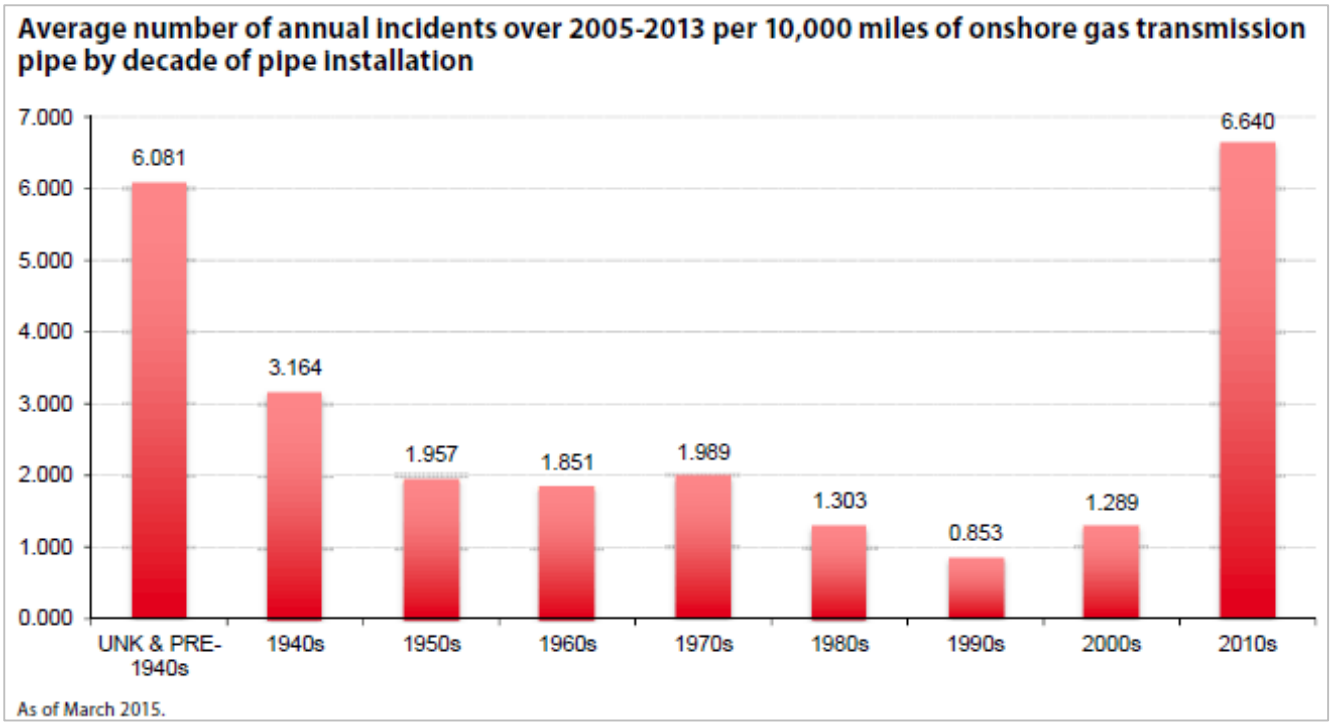
Figure 5. Pipeline incidents on newly installed pipelines are comparable to those installed pre-1940.



Source: U.S. Pipeline and Hazardous Materials Safety Administration, Pipeline Safety Trust

Risks Associated With Natural Gas

Risks Associated With Natural Gas

Risks Associated With Natural Gas

One core similarity between the Atlantic Coast Pipeline and the Mountain Valley Pipeline is that they both have been proposed as affiliate transactions, meaning that the majority of the capacity on both of the lines has been reserved by companies that are affiliates of the same companies that are building the lines.

The projects are structured differently, however. Construction of the Atlantic Coast Pipeline is driven by natural gas utilities. Suppliers, not utilities, are driving construction of the Mountain Valley pipeline. This is a difference that raises ratepayer and investor risks that are unique to each project. In particular, IEEFA finds that the utility-driven Atlantic Coast Pipeline places most of the risk on ratepayers, whereas the Mountain Valley Pipeline poses greater risks for investors.

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Proposed

Developers of the proposed 550-mile Atlantic Coast Pipeline propose bringing gas from the Marcellus region of northern West Virginia into Virginia and North Carolina.[37] The pipeline would carry up to 1.5 million dekatherms per day. The pipeline would be developed, owned and operated by a joint venture of Dominion Resources (which has a 45% interest in the venture), Duke Energy (40%), Piedmont Natural Gas Company (10%) and AGL Resources (5%).[38] AGL Resources is the target of a possible acquisition by the Southern Company, a deal which is expected to close in the second half of 2016.[39] Piedmont Natural Gas Company is the target of a pending acquisition by Duke Energy, also expected to close in the second half of 2016.[40] If both acquisitions go through, the ownership stake in the pipeline would be 48% Dominion, 47% Duke and 5% Southern.[41] The pipeline is expected to cost $5 billion, and developers anticipate putting the project into service in late 2018.[42]

Developers applied to FERC for a certificate of need in October 2015 with 96% of the capacity of the pipeline already subscribed. The contracts for the majority of this capacity are with utility - companies that are subsidiaries of the companies proposing the project. That is, developers of Atlantic Coast justify need for the line based on contracts negotiated with shippers who are affiliates of the same companies building the pipeline. The following table shows the six companies that have contracted to ship gas on the Atlantic Coast Pipeline.[43]

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[37] As originally proposed, the Atlantic Coast Pipeline route starts in Harrison County WV, traversing Lewis, Upshur, Randolph and Pocahontas counties in WV; Highland, Augusta, Nelson, Buckingham, Cumberland, Prince Edward, Nottoway, Dinwiddie, Brunswick and Greenville counties in VA; and Northampton, Halifax, Nash, Wilson, Johnston, Sampson, Cumberland and Robeson counties in North Carolina. In February 2016, the developers proposed a revised route for the pipeline after the National Forest Service objected to the original route because of impacts to endangered species. The new route adds Bath County, VA to the list of counties traversed by the pipeline. (Sources: Atlantic Coast Pipeline, "Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates: Volume 1, Exhibit F," Federal Energy Regulatory Commission Case No. CP15-554, September 18, 2015; X. Mosqueda-Fernandez, "Forest Service staff rejects Atlantic Coast pipeline route," SNL Financial, January 21, 2016; X. Mosqueda-Fernandez, "Atlantic Coast Pipeline forges alternative route with Forest Service," SNL Financial, February 12, 2016).

[38] More specifically, each of these companies has set up subsidiaries to hold their interests in the project. The ownership interests therefore belong to Dominion Atlantic Coast Pipeline, LLC; Duke Energy ACP, LLC; Piedmont ACP Company, LLC; and Maple Enterprise Holdings, Inc., a subsidiary of AGL.

[39] "Southern Company acquires AGL Resources Inc.: Deal Profile," SNL Financial, last accessed April 12, 2016.

[40] D. Sweeney, "In NC merger application, Duke Energy, Piedmont outline benefits of combined company," SNL Financial, January 19, 2016.

[41] J. Dumoulin-Smith, M. Weinstein and P. Zimbardo, "Dominion Resources: A Plainer Dominion," UBS Global Research, January 29, 2016.

[42] X. Mosqueda-Fernandez, "Atlantic Coast Pipeline forges alternative route with Forest Service," SNL Financial, February 12, 2016.

[43] Atlantic Coast Pipeline, "Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates, Resource Report 1: General Project Description", Federal Energy Regulatory Commission Case No. CP15-554, September 18, 2015, page 1-11.

Table 1. Utilities contracted to ship gas on the Atlantic Coast Pipeline. All but Public Service Company of North Carolina are subsidiaries of companies involved in developing the pipeline.

Utility	Parent	Contracted capacity (dekatherms/day)
Virginia Power Services	Dominion	300,000
Duke Energy Progress	Duke	452,750
Duke Energy Carolinas	Duke	272,250
Piedmont	Piedmont Natural Gas	160,000
Public Service Company of North Carolina	SCANA Corporation	100,000
Virginia Natural Gas	AGL Resources	155,000

According to Atlantic Coast's application to FERC, a large portion of the gas (79%) that would be shipped through the pipeline would be destined for power generation in Virginia and North Carolina.[44] Of this amount, 86% would go to Duke and Dominion.[45]

The extent to which Dominion needs this new pipeline capacity to deliver natural gas to planned and proposed new natural gas plants in Virginia is questionable. The application to FERC cites the need for natural gas to supply Dominion's new Brunswick natural gas plant (currently under construction) and its planned Greensville natural gas plant. Both plants have received approval from the Virginia State Corporation Commission. In seeking approval for the Brunswick plant, Dominion represented that the plant would have a contract for firm natural gas supply from Transcontinental Gas Pipe Line Company ("Transco"), which was to construct nearly 100 miles of new pipeline to connect to the Brunswick Plant.[46] This pipeline was completed and placed into service in September 2015.[47] Similarly, for the Greensville plant, Dominion represented that the plant "will be fueled using 250,000 Dth per day of natural gas with reliable firm transportation provided by Transcontinental Gas Pipe Line Company, LLC" though it also noted that Greensville "will also have access to" Atlantic Coast.[48] The Transco pipeline is expected to be placed into service by December 2017.[49] Thus, in its applications to the Virginia State Corporation Commission, Dominion has represented that the Brunswick and Greensville plants will be supplied with natural gas from Transco. The Virginia State Corporation

[44] The remainder will be used for natural gas heating, industrial uses and commercial uses such as vehicle fuel. (Source: Atlantic Coast Pipeline, "Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates, Resource Report 1: General Project Description", Federal Energy Regulatory Commission Case No. CP15-554, September 18, 2015, page 1-5.)

[45] Atlantic Coast Pipeline, "Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates, Resource Report 1: General Project Description", Federal Energy Regulatory Commission Case No. CP15-554, September 18, 2015, page 1-12.

[46] State Corporation Commission of Virginia, Case No. PUE-2012-00128, "Application of Virginia Electric and Power Company for approval and certification of the proposed Brunswick County Power Station electric generation and related transmission facilities under §§56-580 D, 56-265.2 and 56-46.1 of the Code of Virginia and for approval of a rate adjustment clause, designated Rider BW, under § 56-585.1 A 6 of the Code of Virginia," November 2, 2012.

[47] Williams, "Press release: Williams' Transco Completes Virginia Southside Expansion," September 1, 2015, online at: http://investor.williams.com/press-release/williams/williams-transco-completes-virginia-southside-expansion.

[48] State Corporation Commission of Virginia, Case No. PUE-2015-00075, "Application of Virginia Electric and Power Company for approval and certification of the proposed Greensville County Power Station and related transmission facilities pursuant to §§56-580 D, 56-265.2 and 56-46.1 of the Code of Virginia and for approval of a rate adjustment clause, designated Rider GV, pursuant to § 56-585.1 A 6 of the Code of Virginia," July 1, 2015.

[49] Williams, "Virginia Southside Expansion Project II," online at http://co.williams.com/expansionprojects/virginia-southside-expansion-project-ii/, last accessed April 13, 2016.

Commission has already approved construction of both gas plants without requiring any additional natural gas contracts.

The Atlantic Coast pipeline could be used as a back-up gas supply for Dominion's Brunswick and Greensville plants. Contracting for some amount of redundant natural gas supply may be prudent. But the Virginia State Corporation Commission approved the plants without any discussion of need for a redundant pipeline.[50] The question of how much redundant supply might be prudent is not likely to be addressed when FERC considers the need for the Atlantic Coast pipeline.

Moreover, Dominion's most recent integrated resource plan, which lays out its long-term plan for electricity supply, does not provide a clear vision for Dominion's natural gas expansion plans. The IRP describes four scenarios that are compliant with the Clean Power Plan; these scenarios vary substantially in the amount of new natural gas generation called for. The least gas-intensive scenario calls for building one additional 1,585 MW natural gas baseload combined cycle power plant in 2022 and two 457 MW natural gas peaking plants by 2030. The most gas-intensive scenario calls for building two 1,585 MW baseload plants, three 457 MW peaking plants and repowering several existing plants with natural gas. The IRP does not express a preference between these scenarios.[51]

While Duke and Dominion are required to file integrated resource plans showing their detailed natural gas capacity expansion plans with state regulators in Virginia and North Carolina, these plans have not been filed with FERC. Thus, FERC will not be able to scrutinize these plans in assessing the need for the Atlantic Coast Pipeline.

Risks Associated With Natural Gas

Ratepayers—specifically the customers of Dominion Virginia Power, Piedmont, Virginia Natural Gas, Public Service Company of North Carolina, Duke Energy Progress and Duke Energy Carolinas—are on the hook for 96% of the project's costs through the rates that they are charged to ship gas on the pipeline.

These ratepayers will bear the following risks.

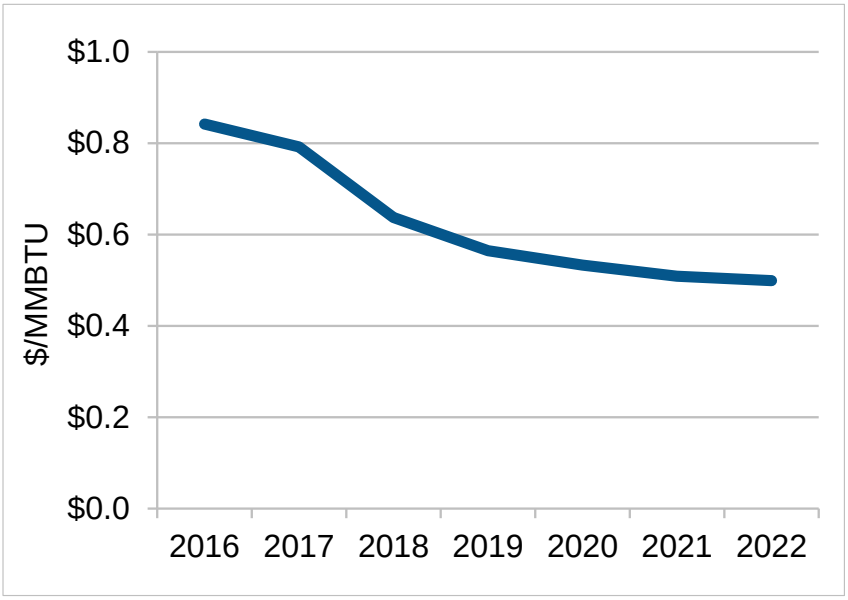
One is that the Atlantic Coast pipeline would go underutilized. As described above, it is not clear that the utilities that have contracted to ship gas on the pipeline actually need all of the gas that they are contracted to purchase. The utilities have the option to sell the capacity that they're not using on the secondary market and crediting this money back to ratepayers. If the excess capacity cannot be sold, ratepayers will pay for the capacity that their utilities are under contract to purchase. If the excess capacity can be sold, ratepayers still bear the risk that the price received for this capacity is less than what they are paying for it.

[50] State Corporation Commission of Virginia, "Final Order," Case No. PUE-2012-00128, August 2, 2013.
[51] Dominion, Integrated Resource Plan, as filed with the Virginia State Corporation Commission and the North Carolina Utilities Commission, July 1, 2015, pp. 5-8.

Ratepayers are also at risk that natural gas prices from the Marcellus and Utica region will not continue to be significantly cheaper than Henry Hub prices. Part of the supposed rationale for building the Atlantic Coast Pipeline is that ratepayers will benefit from a cheap supply of natural gas from the Marcellus and Utica region. But ratepayers would benefit only if the cost advantage of sourcing gas from the Marcellus/Utica outweighs the cost to ratepayers of building the pipeline. While a study conducted on behalf of the developers by ICF International to justify the economic benefits of the pipeline does not provide a forecast of future natural gas prices from the Marcellus region, it does assert that Marcellus/Utica natural gas will continue to be $1-$1.75/MMBTU cheaper than natural gas from the Henry Hub through 2035, which would mean that the Atlantic Coast pipeline would generate savings for ratepayers over the lifetime of the pipeline. However, ICF's projection of a widening spread between Henry Hub and Marcellus/Utica gas (at the Dominion South Hub) contradicts current market expectations. ICF projects the price difference between the Dominion South Hub and the Henry Hub narrowing to about $0.50/MMBTU by 2018 but then steadily increasing to about $1/MMBTU by 2022 and $2/MMBTU by 2028.[52] By contrast, current market expectations, as revealed by futures prices, project the spread between the two hubs steadily narrowing to $0.50/MMBTU by 2022.

As more pipelines are built out of the Marcellus and Utica region, the excess pipeline capacity will further narrow the price differential between the hubs. That is, as natural gas pipeline capacity increases to meet or exceed the glut of natural gas supply, natural gas prices in the Marcellus should rise. A January 2016 article in Midstream Business noted that "new Marcellus Shale regional pipelines are beginning to pressure Henry Hub prices, *sapping differentials in gas value* as more of the area's production escapes regional lockdown" (emphasis added).[53]

Figure 6. Projected price difference between Henry Hub and Dominion South Hub*



*based on OTC Global Holding futures prices retrieved 2/26/16

[52] ICF International, "The Economic Impacts of the Atlantic Coast Pipeline," February 9, 2015

[53] Darren Barbee, "Contents Under Pressure: New Pipelines Ease Marcellus Takeaway Troubles," Midstream Business, January 12, 2016.

It is clear that the current low natural gas prices in the Marcellus and Utica are not sustainable for drillers, a factor that will likely drive Marcellus and Utica gas prices higher over the long term, likely reducing the price differential with the Henry Hub and affecting ratepayers who are on the hook for shipping contracts for the next 20 years. Many of the companies with the greatest production in Appalachia operated at a loss in 2015. Of the top 10 Appalachian drilling companies, only two (EQT and Antero) posted positive net income in 2015.[54] Chesapeake Energy, the largest Appalachian driller, is widely expected to go bankrupt (though the company is currently denying that it will file for bankruptcy).

In response to continued low prices, drillers have cut back on capital expenditures. Capital expenditures by the top eight Appalachian shale drillers in the fourth quarter of 2015 were 54% lower than in the fourth quarter of 2014. And capital expenditures for the first quarter of 2016 are expected to be 49% lower than in the first quarter of 2015.[55] This reduction in capital expenditures is reflected in production volumes; according to the most recent figures from the Energy Information Administration, production growth has slowed over the past several months and a decline is projected from February to April 2016.[56]

Low oil prices since late 2014 have also hurt many Appalachian drillers who had previously been able to use profitable wet gas drilling operations to prop up less profitable dry gas drilling. Low oil prices have driven down prices for natural gas liquids, making wet gas drilling less profitable.[57]

In spring 2016, banks will be re-determining the revolving credit lines for many shale gas drillers. They are widely expected to cut back on lending.[58]

It is all but certain that the instability and financial problems brought about by current low natural gas prices will drive some of the shale gas drilling companies into bankruptcies. According to JP Morgan there have been 48 bankruptcies in the oil and gas exploration and production sector since 2014,[59] and further bankruptcies are expected in 2016.

Production will be scaled back and prices will stabilize at a higher level. It is not clear over what timeframe this will occur, though natural gas prices are generally expected to remain low at least through 2016. According to Standard & Poor's, "commodity prices will remain low in 2016, impeding cash flows and increasing the risk for negative rating and outlook actions as leverage measures and liquidity continue deteriorating."[60]

While most analysts are not projecting a near-term rise in gas prices (and futures prices show Dominion South Hub prices remaining below $2.50 per MMBTU through 2022), shale drillers cannot continue to produce below cost indefinitely. In the longer term (10-15 years), it is likely that Marcellus and Utica gas prices will stabilize at a somewhat higher level. These longer-term prices will have a significant impact on the long-term economics of the Atlantic Coast Pipeline, which is designed as a 40-year project.

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[54] List of top 10 Appalachian drillers from B. Holland, "Appalachian drillers vow to slow down after brutal Q3," SNL Financial, November 12, 2015. Net incomes obtained from individual company 2015 Form 10-K Securities and Exchange Commission filings.

[55] B. Holland, "Billions evaporate from gas industry as Northeast drillers gut spending," SNL Financial, January 8, 2016.

[56] Energy Information Administration, "Drilling Productivity Report: Report Data," March 7, 2016. https://www.eia.gov/petroleum/drilling/xls/dpr-data.xlsx

[57] X. Mosqueda-Fernandez, "NGL projects could struggle under low crude price future," SNL Financial, June 17, 2015.

[58] B. Holland, "JP Morgan clamping down on oil, gas clients, expects more bankruptcies," SNL Financial, February 24, 2016.

[59] Ibid.

[60] B. Holland, "Lack of oil, gas hedging could lead drillers to spring defaults, S&P warns," SNL Financial, December 21, 2015.

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Thus, ratepayers run the risk of paying higher than expected natural gas prices for gas delivered on the Atlantic Coast pipeline as the difference between Marcellus and Henry Hub natural gas prices narrows.

Ratepayers also bear risks associated with delays in project construction. It is not clear how much of the risk of project delay would be borne by ratepayers versus investors in the project. According to Atlantic Coast's application to FERC, "in an agreed-upon risk sharing agreement, the negotiated rates would be decreased by specified amounts for certain delays in the Project in-service date."[61] The developers offer no further detail on how the risk of delay would be shared among project investors and ratepayers. Given that the negotiated rates were negotiated between affiliated companies, it seems likely that the burden of the risk would be placed on ratepayers, not project investors.

Ratepayers may also bear some risk of construction cost overruns. Dominion has noted that the terrain that the Atlantic Coast pipeline will traverse accentuates the risk of construction cost overruns and delays: "The large diameter of the pipeline and difficult terrain of certain portions of the proposed pipeline route aggravate the typical construction risks with which DTI [Dominion Transmission Inc] is familiar. In-service delays could lead to cost overruns and potential customer termination rights."[62]

Atlantic Coast pipeline's application to FERC provides no additional detail on these "potential customer termination rights." It is not clear whether customers would be able to terminate their contracts and walk away with the project without any losses, or whether they would still end up paying for a portion of the project if their contract is terminated.

Finally, ratepayers face the risk of future regulation of greenhouse gas emissions. The Atlantic Coast Pipeline is designed to recover its construction costs from ratepayers over a 40-year period, i.e. through 2058. It is reasonable to expect significant policies requiring reductions in greenhouse gas emissions by then, changes that will constrain the use of natural gas.

Risks Associated With Natural GRisks Associated With Natural Gas

Generally speaking, the Atlantic Coast pipeline does not appear to be particularly risky to investors. The pipeline will be paid for through shipping rates paid by financially stable, regulated utilities with captive customers.

Nevertheless, there are still investor risks.

First is that a state utilities commission (either the North Carolina Utilities Commission or the Virginia State Corporation Commission) will disallow some of the costs of the pipeline from being passed through to ratepayers based on a decision that the costs were imprudently incurred. Such a decision would likely be predicated on a conclusion that the utility had contracted for more capacity than it needs, based on what was known about future natural gas demand at the time the contract was entered into.

Investors also face the risk of delays or construction cost overruns that cause shippers to back out of the project or to receive lower rates. As described in the previous section, delays and

[61] Atlantic Coast Pipeline, "Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates: Volume 1," Federal Energy Regulatory Commission Case No. CP15-554, September 18, 2015, p. 32.
[62] Dominion Resources, 2014 Form 10K, p. 26.

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cost overruns could trigger shippers to pull out of the project, though it is not clear what level of delay or cost overrun would be required to allow a shipper to terminate its contract. Furthermore, developers of the Atlantic Coast project have apparently agreed to lower negotiated rates if the project is delayed by a certain amount though, again, there are no details on these agreements. Given that these contracts are largely between affiliated entities, it seems reasonable to assume that the risks of delay and cost overruns will be borne more by ratepayers than by investors.

Investors are also at risk that the pipeline owners would not be able to renew shipping contracts after 20 years. The contracts that Atlantic Coast has signed with shippers are all 20-year contracts. Yet the rates charged in these contracts are designed to recover the costs of the constructing the pipeline over a 40-year period.[63] Thus, Atlantic Coast is banking on its ability to renew shipping contracts in order to fully recover the costs of building the pipeline. The risk of not being able to renew these contracts is, in theory, borne by the project's investors. However, given that almost all of Atlantic Coast's shipping contracts are with affiliates, there will be strong pressure on the regulated utilities to renew the contracts. IEEFA therefore views this as a minimal risk to investors.

ProposedProposed

The Mountain Valley Pipeline is a proposed 300-mile pipeline that originates in West Virginia and terminates in Virginia.[64] The Mountain Valley Pipeline would carry up to 2 million dekatherms per day. It is a joint venture of EQT Midstream (45.5% ownership interest), NextEra Energy (31%), Con Edison (12.5%), WGL Holdings (7%), Vega Energy Partners (3%) and RGC Resources (1%) and will be operated by a subsidiary of EQT.[65] The pipeline is expected to cost $3.7 billion and to go into service in the fourth quarter of 2018.[66]

All of the capacity on the Mountain Valley Pipeline has been reserved by shippers. The companies that have entered into shipper contracts are EQT (64.5%), Consolidated Edison (12.5%), USG Properties Marcellus Holdings, a subsidiary of NextEra (12.5%), WGL Midstream (10%) and Roanoke Gas (0.5%). EQT and USG Properties Marcellus Holdings, which together have contracted for 77% of the capacity of the pipeline, are natural gas supply companies.

The Mountain Valley Pipeline is very different from the Atlantic Coast Pipeline in that is a supplier-driven pipeline, rather than a customer-driven pipeline. That is, the entities that have entered into long-term contracts for the majority of the capacity on the Mountain Valley Pipeline are producers of natural gas.

As shown in the following table, the entities that have entered into contracts for capacity on the Mountain Valley Pipeline are all affiliates of the companies that are partners in the joint

[63] Atlantic Coast Pipeline, "Abbreviated Application for a Certificate of Public Convenience and Necessity and Blanket Certificates: Volume 1, Exhibit P," Federal Energy Regulatory Commission Case No. CP15-554, September 18, 2015

[64] The proposed route starts in Wetzel County and traverses Harrison, Doddridge, Lewis, Braxton, Webster, Nicholas, Greenbrier, Summers and Monroe counties in WV; and Giles, Craig, Montgomery, Roanoke, Franklin and Pittsylvania counties in VA. The pipeline route terminates at an intersection with the Transco line, a pipeline owned by Williams Corporation that is a backbone of the East Coast natural gas transmission system, connecting the Gulf Coast to New York. (Source: Mountain Valley Pipeline, "Application for Certificate of Public Convenience and Necessity and Related Authorizations: Volume 1, Exhibit F," Federal Energy Regulatory Commission Case No. CP16-10, October 23, 2015.)

[65] Mountain Valley Pipeline, "Frequently Asked Questions," http://mountainvalleypipeline.info/faqs/, last accessed April 12, 2016.

[66] S. Sullivan, "Mountain Valley applies to FERC for 2-Bcf/d gas pipeline," SNL Financial, October 23, 2015.

venture. The pipeline is fully subscribed. EQT is, by far, the largest shipper, as well as being the dominant partner in the joint venture to build the pipeline.

Table 2. All of the shippers on the Mountain Valley Pipeline are affiliates of companies involved in developing the project.

Pipeline owner	Ownership interest	Shipper	Capacity contracted (dekatherms/day	Capacity contracted (%)
EQT Midstream Partners, LP	45.5%	EQT Energy, LLC	1,290,000	64.5%
NextEra Energy US Gas Assets, LLC	31%	USG Properties Marcellus Holdings, LLC	250,000	12.5%
Con Edison Gas Midstream, LLC	12.5%	Consolidated Edison Company of New York	250,000	12.5%
WGL Midstream, Inc.	7%	WGL Midstream, Inc.	200,000	10%
Vega Midstream MVP LLC	3%			
RGC Midstream LLC	1%	Roanoke Gas Company	10,000	0.5%

Investors in the Mountain Valley Pipeline are at greater risk of being harmed by financial problems with the shippers than investors in the Atlantic Coast Pipeline are because natural gas producers are much less financially stable than regulated utilities. According to Moody's Investor Services, the long-term credit rating of EQT is Baa3 (the lowest investment-grade credit rating), whereas the largest shippers on the Atlantic Coast pipeline have credit ratings of A1 (Duke Energy Carolinas) and A2 (Duke Energy Progress and Dominion Virginia Electric and Power Company).

In recent months, investors have grown increasingly aware of the risks of supplier-driven pipelines, like the Mountain Valley Pipeline, because of the weak financial position of many shale drilling companies. As described by SNL Financial:

> "Firm transportation contracts with counterparties that have credit ratings below investment grade, such as Chesapeake Energy Corp., have the potential to disrupt operators if the shippers cannot keep up with reservation payments for the duration of the contracts.
>
> As oil and gas prices remain depressed, exploration and production companies have continued to watch their valuations fall. These upstream problems may work their way down the value chain, putting previously stable revenue for midstream companies at risk as their contract counterparties look to renegotiate pricing, or in some instances, file for bankruptcy. Pipelines with higher proportions of volume contracted with these companies are more exposed to these effects."[67]

Two pending bankruptcy proceedings are raising the issue of whether drillers' contracts with pipelines are likely to be honored if the drillers go bankrupt. In its pending bankruptcy

[67] M. Bearden, "Exploring interstate pipeline exposure to lower-rated E&Ps," SNL Financial, February 18, 2016.

proceeding, Sabine Oil & Gas successfully terminated its contracts with natural gas pipeline companies for gathering and processing natural gas.[68] Quicksilver Resources, also in bankruptcy, is following suit, seeking to terminate its contracts for gathering and processing.[69] Similarly, while Chesapeake Energy – the largest company drilling in the Marcellus shale—has denied plans to file for bankruptcy,[70] it is experiencing serious financial troubles and a bankruptcy would potentially jeopardize its payments to pipeline companies with which it is contracted to ship gas.

In the case of the Mountain Valley Pipeline, the financial health of EQT is critical to how the project moves forward. EQT is a major shale gas drilling company whose operations are concentrated in the Marcellus and Utica shale region (78% of its proved reserves are in the Marcellus).[71] As described in the previous section, the shale drilling sector in general is in turmoil because of prolonged low natural gas prices. While EQT is positioned better than many other major Appalachian shale drillers (it was one of only two of the top ten Appalachian drillers to post positive net income in 2015, for example), it is still not immune to the effects of low prices. EQT's stock price has fallen 26% since January 2014, a period in which the Dow Jones Industrial Average has increased 8%.[72] Its long-term credit ratings from S&P, Moody's and Fitch are all one notch above junk status.[73] Additionally, as of December 2015, EQT had only 37% of its production hedged for 2016, lower than Antero, Range and several other major Appalachian drillers.[74]

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EQT has had negative free cash flow for the past nine years, meaning that the cash generated from drilling operations is not sufficient to finance the ongoing capital expenditures of the company. While it is standard industry practice to rely upon equity and debt cash infusions during a period of growth, this is done with the expectation that project returns will occur over a longer period and cash flow will flip from negative to positive as projects start generating returns. EQT's long period of negative free cash flow reflects a decision to continue investing in the drilling business despite the poor short-term future outlook. In a time when many companies are facing distressed financial scenarios, a nine-year negative free cash flow raises the company's risk profile. EQT's situation appears to be worsening, with free cash flow declining from -$450 million in 2013 to -$1,217 million in 2015.

EQT's business outlook remains focused on growth and, so far, investors have been willing to continue investing in EQT. Despite low prices, EQT's natural gas production volume increased 27% in 2015 over 2014.[75] Part of EQT's growth strategy has been to grow its pipeline business, a less risky line of business than natural gas drilling. EQT launched the master limited partnership EQT Midstream in 2012. EQT has sold pipeline assets to EQT Midstream to raise cash, and EQT Midstream has raised money through public offerings. In 2015, for example, EQT raised $1.1

[68] B. Holland, "E&P bankruptcy ruling brings clouds for midstream and a 'kind of' silver lining," SNL Financial, March 9, 2016.
[69] N. Amarnath, "More trouble for midstream MLPs as struggling producers seek to ditch contracts," SNL Financial, February 9, 2016.
[70] M. Passwaters, "Chesapeake says it is not seeking bankruptcy as shares plummet," SNL Financial, February 8, 2016.
[71] EQT, 2015 Form 10-K, page 10.
[72] SNL Financial, "EQT Corporate Profile," retrieved April 17, 2016.
[73] Baa3 from Moody's, BBB from S&P and BBB- from Fitch. (Source: SNL Financial)
[74] B. Holland, "Lack of oil, gas hedging could lead drillers to spring defaults, S&P warns," SNL Financial, December 21, 2015.
[75] EQT, 4Q 2015 earnings call transcript, February 4, 2016.

billion from sales of assets to EQT Midstream, and EQT Midstream was able to raise $1.2 billion through public offerings.[76] The Mountain Valley Pipeline represents a major area of growth for EQT Midstream.

In part because of its infusions of cash from EQT Midstream, EQT would be in a strong position to be able to buy up the assets of other natural gas drillers who are in financial distress due to low natural gas prices. EQT's basic business strategy is to continue growing and hope that it will be well-positioned to take advantage of higher natural gas prices in the future.

The key question, of course, is how long natural gas prices will stay low. The longer they do, the riskier EQT's business strategy becomes. Natural gas prices at the Dominion South Hub averaged $1.50/MMBTU in 2015 and futures prices project prices falling further to $1.22/MMBTU in 2016, before rising to $1.70 in 2017 and $1.93 in 2018. Fitch has estimated that the average cost of production in the Marcellus shale is $2.50, implying that futures prices for the next few years are expected to be below the average cost of gas production.[77] As noted in a recent article in SNL Financial, "Most independent gas drillers have finally resigned themselves to low prices indefinitely (the highest price on the NYMEX gas futures strip is $4.611/MMBtu all the way at the end, December 2028) and are now in a race to wrangle their expenses inside their cash flow before they default."[78]

Even if EQT is better positioned to withstand continued low natural gas prices than other Appalachian drillers, it would be adversely affected by the bankruptcies that are widely expected in the sector, which will likely drive capital out of the entire drilling sector.

Risks Associated With Natural GasRisks Associated With Natural Gas

In addition to the fundamental risk posed by EQT's weak financial condition, other risks to investors include the risk that the pipeline owners will be unable to renew shipping contracts after 20 years. As with the Atlantic Coast pipeline, the rates for the Mountain Valley Pipeline are designed to recover the costs of the pipeline over 40 years, which is longer than the length of the initial shipping contracts.[79] Pipeline investors bear the risk that Mountain Valley will not be able to renew its shipping contracts after 20 years or that it will not be able to renew them with as favorable terms.

This risk is compounded by the risk that greenhouse gas regulations imposed over the next 20 years will restrict the use of natural gas.

Investors also may be vulnerable to cost-overrun risks. Mountain Valley's shipping contracts includes a provision for adjusting the negotiated rates if the actual construction cost differs from the estimated cost, but the nature of this adjustment is not publicly available.[80]

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[76] EQT Form 10-K, February 11, 2016, pp. 78-79.
[77] B. Holland, "Fitch warns Marcellus prices fail to cover costs as Pa. cash hubs drop below $1," SNL Financial, November 2, 2015.
[78] B. Holland, "Gas world faces reckoning of drillers' 'growth at the expense of profit'," SNL Financial, December 28, 2015.
[79] Mountain Valley Pipeline, "Application for Certificate of Public Convenience and Necessity and Related Authorizations: Volume 1," Federal Energy Regulatory Commission Case No. CP16-10, October 23, 2015, p. 38.
[80] Mountain Valley Pipeline, "Application for Certificate of Public Convenience and Necessity and Related Authorizations: Volume 1, Exhibit I," Federal Energy Regulatory Commission Case No. CP16-10, October 23, 2015, p. 160.

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Communities and landowners along the pipeline route also bear risks that stem from EQT's financial weakness. EQT does not appear to be a stable, long-term partner for these communities.

EQT's weakened financial position suggests it will adopt only a limited commitment to communities or perhaps be forced to sell its ownership interests to a new company that is not part of current deliberations. Natural gas pipelines are not just long-term investments between companies and investors, they are long-term partnerships between the companies and their host communities. Company culture matters.

Another risk to communities directly affected by the proposed project: Pipeline safety problems are on the rise, as documented in Figure 5, and how a company perceives such risk, monitors for it, seeks to prevent it, and communicates about it to affected communities is paramount. Closely related to this risk are those that stem from a company's land management and reclamation activities. Companies involved in positive corporate citizenship buy locally to stimulate local businesses, hire locally, and invest locally in new businesses and community projects.

The clearest risks to ratepayers from the Mountain Valley Pipeline are the risks to the customers of the regulated utilities that have contracted as shippers on the pipeline. These are Consolidated Edison and Roanoke Gas.

The risks to ratepayers on the Mountain Valley Pipeline are similar to those posed by the Atlantic Coast Pipeline.

These include the risk of project delay. According to the contracts that have been signed by shippers on the Mountain Valley pipeline, a shipper many terminate its contract if the pipeline has not been placed into service by June 1, 2020, but it is still required to pay its share of the expenses incurred to that date, plus fifteen percent unless the developer can re-sell the shipper's capacity to a third party. In other words, ratepayers may be on the hook for a share of construction costs even if the utilities ultimately pull out of the project.[81]

Ratepayers are at risk that natural gas prices from the Marcellus shale will not turn out to be substantially lower than Henry Hub prices over the long term. Customers of the regulated utilities that have contracted to ship gas on the Mountain Valley Pipeline will pay for their share of the construction cost of the pipeline through their rates. If the expense of the pipeline outweighs the savings from access to a lower-cost supply of natural gas, then this cost will be borne by ratepayers.

Finally, the potential for greenhouse gas regulations poses a ratepayer risk. As with the Atlantic Coast pipeline, it is likely that ratepayers will bear the cost of their utilities' share of the stranded capacity on the Mountain Valley pipeline if and when greenhouse gas emissions regulations restrict the use of natural gas.

[81] Mountain Valley Pipeline, "Application for Certificate of Public Convenience and Necessity and Related Authorizations: Volume 1, Exhibit I," Federal Energy Regulatory Commission Case No. CP16-10, October 23, 2015, p. 166.

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Risks Associated With Natural Gas

Proposed Proposed Proposed Proposed Proposed Proposed

- The establishment of a comprehensive planning process for natural gas pipeline development. FERC's current practice of considering the need for projects on an individual basis is insufficient.
- Lower returns on pipeline development. The returns on equity embedded in recourse rates for new interstate natural gas pipelines exceed authorized returns for state-regulated electric utilities and federally regulated electric transmission lines. This is especially egregious given that the growing trend of transactions between regulated utilities and affiliated pipeline developers tends to shift risk from utility shareholders to ratepayers. FERC should lower the returns it allows on equity for pipeline development.
- An investigation into the safety of new pipelines with a focus on the relatively high failure rate of newly installed pipelines.

Proposed Proposed Proposed Proposed

- The Virginia State Corporation Commission closely examine the prudence of contracts signed by regulated utilities to ship gas on a pipeline owned by affiliated companies.
- FERC consider information presented to state regulators by Duke and Dominion in integrated resource plans and in certificate applications regarding their planned buildout of regional natural gas power generation.

Proposed

- FERC acknowledge that it lacks sufficient evidence to evaluate the need for the Atlantic Coast and Mountain Valley Pipelines and that applications for those project be suspended until such time than an appropriate regional planning process is developed.
- FERC should recognize that pipelines are being proposed with different corporate structures that involve very different risk profiles. In assessing supplier-driven pipelines, FERC should assess industry trends and the short and long term financial condition of companies along the chain (with careful attention paid to leverage and free cash flow). FERC could also consider a range of recourse rates that would reflect different risks.

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Risks Associated With Natural Gas

Natural gas pipeline infrastructure out of the Marcellus and Utica region of Appalachia will probably become overbuilt within the next several years, an outcome recognized by many in the industry itself. The economic and financial factors that incentivize companies to invest in the development of new natural gas pipelines—from drilling companies that seek to diversify into a sector with more stable income to traditional pipeline companies angling to build larger and better-connected networks—will not produce a socially rational outcome. Without a coordinated approach to natural gas pipeline planning, as exists for many other types of infrastructure, the Federal Energy Regulatory Commission cannot make an honest determination of the need for these pipelines. Ratepayers and communities will shoulder much of the costs and risks of the Atlantic Coast and Mountain Valley pipelines, investments of nearly $9 billion that are poised for approval without adequate scrutiny.

Risks Associated With Natural Gas

Proposed Propose**Proposed** is an independent West Virginia-based consultant focusing on energy efficiency and utility regulation. She has testified on multiple occasions before the West Virginia Public Service Commission for the nonprofit coalition Energy Efficient West Virginia. She has done graduate work for the Energy and Resources Group at the University of California-Berkeley and is a former senior research associate at Lawrence Berkeley National Laboratory. Kunkel has an undergraduate degree in physics from Princeton University and graduate degree in physics from Cambridge University.

Proposed is the author of several studies on coal plants, rate impacts, credit analyses, and public and private financial structures for the coal industry. He has testified as an expert witness, taught energy-industry finance training sessions, and is quoted frequently by the media. Sanzillo has 17 years of experience with the City and the State of New York in various senior financial and policy management positions. He is a former first deputy comptroller for the State of New York, where he oversaw the finances of 1,300 units of local government, the annual management of 44,000 government contracts, and where he had oversight of over $200 billion in state and local municipal bond programs and a $156 billion pension fund. Sanzillo recently contributed a chapter to the Oxford Handbook of New York State Government and Politics on the New York State Comptroller's Office.

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Risks Associated With Natural Gas

Risks Associated With Natural Gas

Many details about the Atlantic Coast and Mountain Valley pipelines have not yet come to light in the FERC application process. These details may never come to light through that process because they are not necessarily issues that FERC prioritizes in deciding on the "need" for a pipeline. Nevertheless these are questions that need to be answered if there is to be appropriate public scrutiny over whether these pipelines are worth the risks.

Proposed Proposed

- Why are ratepayers being asked to pay for redundant natural gas supply for Dominion Virginia Electric and Power's Brunswick and Greensville natural gas plants?
- Which specific proposed natural gas plants do Duke and Dominion plan to supply with gas from that Atlantic Coast pipeline? When are these plants expected to be constructed?
- Why have there recently been so many safety problems with new pipelines?
- Dominion's 2014 10-K states, "certain portions of the proposed pipeline route aggravate … typical construction risks." Which portions of the route? What is Dominion doing to minimize these risks?
- Who will be the construction contractor for the Atlantic Coast pipeline? What is this contractor's recent safety track record?
- Who will be liable for damages from pipeline explosions?
- Who will pay for construction cost overruns, shippers or the pipeline developer?
- If a shipper terminates their contract due to project cost overruns or delays, to what extent is that shipper still liable for construction costs of the pipeline?
- What are the rates that have been negotiated between Atlantic Coast and its shippers? What return on equity is embedded in these rates?
- How much do negotiated rates decrease if there are delays in putting the pipeline into service?

Proposed Proposed Proposed

- Who will be the construction contractor for the Mountain Valley pipeline? What is this contractor's recent safety track record?
- Who will be liable for damages from pipeline explosions?
- Who will pay for construction cost overruns, shippers or the pipeline developer?
- What are the rates that have been negotiated between Mountain Valley and its shippers? What return on equity is embedded in these rates?
- How much do negotiated rates decrease if there are delays in putting the pipeline into service?
- If a shipper goes bankrupt, how likely is it that the shipper's contract with Mountain Valley pipeline will be terminated?

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Exhibit B

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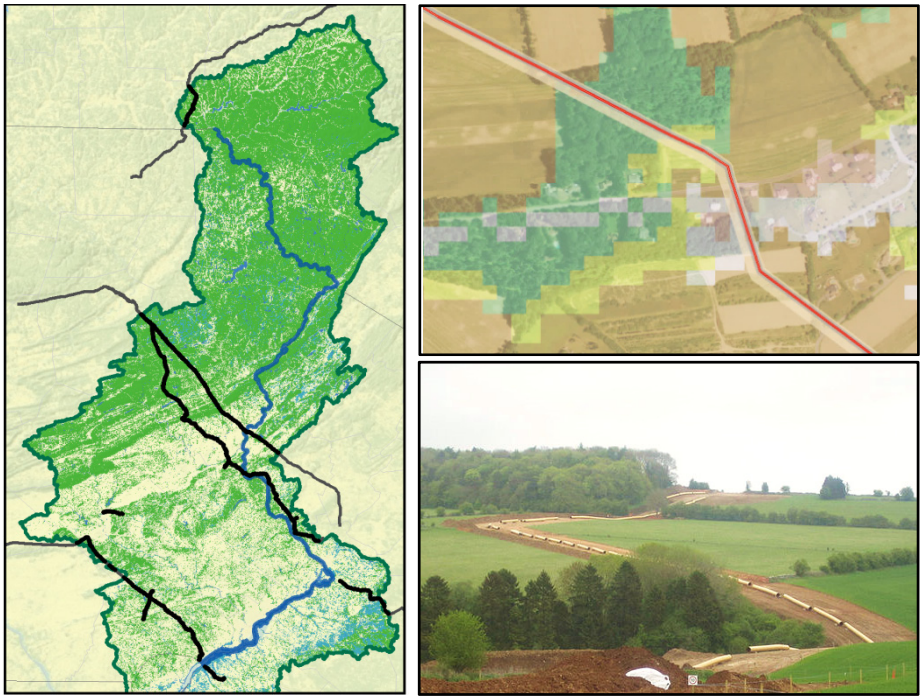
Cumulative Land Cover Impacts of Proposed Transmission Pipelines in the Delaware River Basin

Lars Hanson and Steven Habicht

May 2016



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Authors: Lars Hanson and Steven Habicht, PhD

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Abstract

Transmission pipelines function to transport petroleum products over long distances to connect locations where these products are produced or refined to demand centers. The development of Marcellus shale gas with hydraulic fracturing in Pennsylvania has been accompanied by several proposals for new transmission pipelines. At least eight of these proposed transmission pipeline projects will cross the Delaware River Basin (DRB) to bring natural gas produced from the Marcellus shale play to demand centers on the East Coast, or otherwise connect to the larger petroleum products pipeline network. Each proposed interstate pipeline must undergo a review by the Federal Energy Regulatory Commission (FERC), which includes an environmental impact analysis. The potential environmental impacts of pipeline construction include land cover change, deforestation, sedimentation and erosion, water quality degradation, stream degradation, wetland loss, and air emissions, among others. In this report, we investigate the cumulative land cover change impacts for eight proposed transmission pipelines within the DRB, which total 322 miles in length. Specifically, using geographic information systems (GIS) methods, we investigated total land cover change, loss of forest and wetland area, and stream crossings for the eight proposed projects. We found that during construction, the pipelines' rights-of-way will impact 2,977 acres, including roughly 1,060 acres of forest, and 41 acres of wetlands. The pipelines' permanent rights-of-way will impact 1,328 acres, including roughly 450 acres of forest, and 22 acres of wetlands. In addition, we identified 175 likely stream crossings where a proposed pipeline route will cross a perennial stream.

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Executive Summary

The primary function of transmission pipelines for petroleum is to provide long distance transport of liquid fuels to where there is demand for them. The planning and construction of pipelines can be a long and complicated process because pipelines and the land needed for their rights-of-way impact property owners, land resources, water resources, air quality, and wildlife along the proposed routes. These impacts may be magnified if multiple pipelines are built concurrently.

The rapid expansion of natural gas production due to the development of the Marcellus shale with hydraulic fracturing has been accompanied by proposals for new transmission pipelines. Although there is a moratorium on natural gas development in the Delaware River Basin (DRB), at least eight proposed transmission pipeline projects will cross the DRB in order to bring natural gas produced in the Marcellus to demand centers on the East Coast, or otherwise connect to the larger petroleum products pipeline network. Each proposed interstate natural gas pipeline must undergo a review by the Federal Energy Regulatory Commission (FERC), which includes an environmental impact analysis. The potential environmental impacts of pipeline construction include land cover change, deforestation, sedimentation and erosion, water quality degradation, stream degradation, wetland loss, and air emissions, among others. The environmental analyses in the FERC approval process document many of these potential impacts, and the proposed measures to mitigate these impacts during construction and operation for each pipeline project. However, the environmental analyses for the individual pipeline projects do not consider the cumulative impact of multiple independent pipeline projects proposed concurrently in the same geographic area – in this case, the DRB.

In this report, we investigated the cumulative land cover change impacts for proposed transmission pipelines within the DRB. Specifically, using geographic information systems (GIS) methods, we investigated total land disturbance, loss of forest and wetland area, and stream crossings for eight proposed projects. This work was funded by the Clean Air Council, which requested that CNA provide an estimate of the land area affected by the eight proposed pipeline projects' rights-of-way (ROW) in the DRB and, especially, an estimate of the total forest area that could be lost as a result of pipeline construction.

Figure ES-1 on the following page shows a map of the proposed pipeline routes overlaid on forest and wetland area within the DRB.

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Our results present information that is typical in pipeline environmental analysis, but in new and useful ways. Notably, we present the land disturbance and forest loss broken down by watershed, with totals for the entire DRB. In addition, we compute the new cumulative disturbance area for eight proposed projects (with no double-counting of area where pipelines are adjacent). These cumulative results, presented by watershed, offer a more complete picture of the impact of the pipeline projects in the DRB than the individual, pipeline-specific environmental analyses can offer on their own.

We found that the land disturbance results are very sensitive to the stage of the development process and proximity to other pipelines. For instance, the land disturbance is highest during construction, when a wider ROW is needed for moving equipment. After construction, a smaller permanent ROW is affected, and in some cases, a portion of the permanent ROW may be allowed to return to prior land uses, leaving a smaller permanently cleared area. In addition, pipelines that run adjacent to existing pipelines, and can share a portion of the existing ROW may cause less land disturbance per mile than new, or "greenfield" pipeline projects.

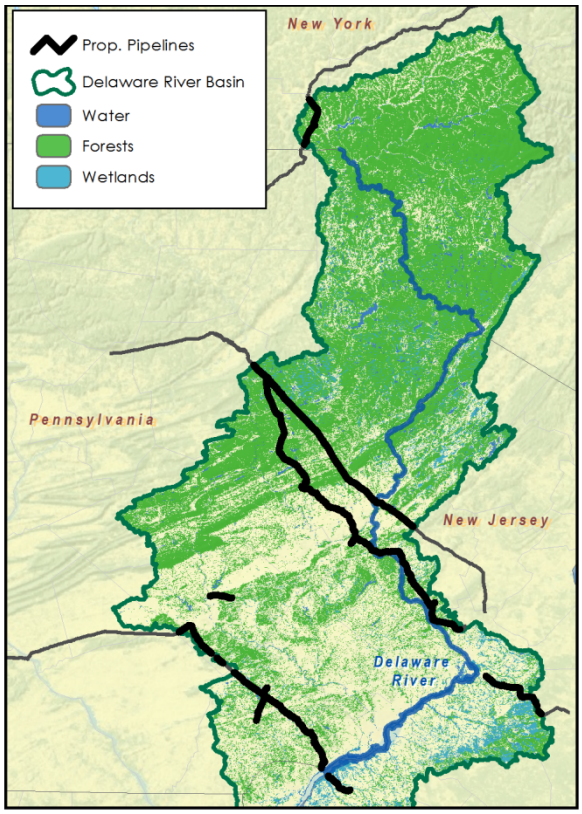

Figure ES-1. Proposed pipelines and forest and wetland areas in the Delaware River Basin

Overall, for the Delaware River Basin, we calculated the following impacts for the eight proposed projects:

- Total land disturbance during construction is 2,977 acres, of which roughly 1,050 are forest, and 41 are wetlands.
- Total land disturbance for the permanent right-of-way is 1,328 acres, of which roughly 440 are forest, and 22 are wetlands.
- The proposed pipeline routes will require at least 175 stream crossings, of which 92 potentially could be shared with existing pipelines.

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The most significant impacts with respect to area of forest and wetland disturbance, as well as stream crossings, will happen in the central part of the DRB, in the Lehigh and Middle Delaware subbasins. This concentration of impacts is caused by the Diamond East, Leidy SE, and especially the PennEast pipeline project (which accounts for 40–50 percent of the total land disturbance area in the DRB) passing through a similar corridor, which is heavily forested. Analyzing multiple pipeline projects simultaneously allows easier detection of these types of concentrated impacts. The body of the report contains many more tables, figures, and maps that break down results by pipeline, county, and subwatershed in much more detail.

These results offer a clear picture of the potential scale of pipeline development impacts on land cover across the Delaware River Basin, offering stakeholders a significantly different view than they might receive when reviewing individual projects. In the future, similar methodology may be used to investigate impacts in other geographic areas of interest. Or, these results could be used to conduct follow-on analyses of secondary impacts of pipeline infrastructure development in the DRB such as forest fragmentation, or water quality pollutant loadings.

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Glossary

DRB	Delaware River Basin
EIS	Environmental Impact Statement
GIS	geographic information systems
FERC	Federal Energy Regulatory Commission
HDD	horizontal directional drilling
NHD	National Hydrography Dataset
NLCD	National Land Cover Dataset
ROW	Right-of-way
USGS	United States Geological Survey
ac	acres
ft	feet
mi	miles
easement	Legal term to describe the holding of land area to ensure access to pipelines (see "right-of-way").
gathering pipeline	Small diameter pipelines used to transport from wells to the larger gas pipeline network.
greenfield	Term to describe construction in a new right-of-way
looping	Type of pipeline project in which a new pipeline is added parallel to an existing pipeline, and connected at both ends to form a 'loop' allowing for greater capacity and control of flow.
play	A geologic formation containing petroleum (natural gas) resources with potential for development.
right-of-way	The land area around a pipeline needed for access to construct the pipeline and protect, and maintain it over time. Typically wider during construction.
spoil side	Term to describe the side of the pipeline ROW where the excavated soil ("spoils") will be stored during construction.
well pad	The location from which gas wells are drilled from the surface into the shale. Typically, flat, covered with gravel, and two–five acres in size to accommodate equipment needed for well drilling.
working side	Term to describe the side of the pipeline ROW where construction equipment travels, and pipeline segments are laid out and assembled.

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Introduction

Over the past decade, the rapid expansion of unconventional natural gas development with hydraulic fracturing in the Marcellus Shale has been accompanied by an increase in pipeline construction proposals in Pennsylvania, New Jersey and New York. The process of shale gas development requires many miles of small gathering pipelines to connect well pads where gas is extracted to transmission pipelines that allow the gas to reach customers. In recent years, the operators of these transmission pipelines have proposed both upgrades and extensions to existing pipeline networks and entirely new pipelines. Many of these proposed pipelines cross the Delaware River Basin by virtue of its location between the Marcellus Shale and densely populated areas with demand for natural gas on the East Coast. It is these proposed transmission pipelines that are the focus of this analysis.

Interstate natural gas transmission pipelines (those that involve building infrastructure in more than one state) must be authorized by the Federal Energy Regulatory Commission (FERC).[1] The typical process is for the pipeline proponent to notify FERC of intention to build an interstate transmission pipeline, followed by the pipeline proponent marketing the pipeline to determine if enough contracts can be sold to build it, followed by a much more detailed route and design process. Then the pipeline proponent works in tandem with FERC staff to perform necessary environmental reviews before finalizing the pipeline route, acquiring necessary permits from relevant federal and state agencies, negotiating with land owners, developing construction plans, and building the pipeline [1]. The scope of the FERC environmental review process is broad, covering land use change impacts, water use, stream crossings and wetland impacts, potential impacts to species (fish, wildlife, and vegetation), soils, and air emissions, among others (including socioeconomic and cultural resource impacts) [2].

Pipelines, as linear features, bring a different set of challenges than most land development activities. While the pipeline itself requires a trench no more than a few

[1] This study also investigates a few transmission pipelines transporting other liquid fuels, and intrastate gas pipelines (those that do not cross state lines), which do not require FERC approval, but have very similar construction methods and impacts on land and water resources.

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feet wide, the construction process requires a much wider right-of-way (ROW) area. In addition, the linearity of pipeline projects means that they cross numerous property boundaries, municipalities, and watersheds. The impact on any one of these geographic entities is typically limited, but over the entire length of the pipeline, the total land disturbance area can be significant. Furthermore, several pipelines built in the same area can cause larger cumulative impacts than the individual projects.

Pipeline construction can result in a wide range of environmental impacts, some of them interacting and layered. Experts studying the risks of shale gas development term the chain of potential impacts a "Risk Pathway," which describes how an *activity* (pipeline construction) leads to *burdens* (land cover change) that create *intermediate impacts* (e.g., forest fragmentation), leading to *final impacts* or *outcomes* (e.g., ecosystem change) [3-4]. In the case of pipeline construction, among the most well-known burdens and intermediate impacts are stream and wetland crossing impacts, land cover change, forest fragmentation, and habitat loss [5-9]. These impacts can lead to other impacts and outcomes, including ecosystem changes (relative changes in species abundance, impacts on specialist or threatened and endangered species), and hydrologic and water quality impacts resulting from the land disturbance (erosion and sedimentation, flow changes, and stream buffer impacts) [5, 10-12]. The hydrologic and water quality changes may in turn impact aquatic ecosystems in streams and wetlands [3, 5].

The FERC environmental review process does investigate many of these impacts in a series of resource reports and environmental assessments, often in detail, but there are some shortcomings for the projects examined in this report. Notably, the land cover change estimates are often broken down by political boundaries, but not always relevant natural boundaries, especially watersheds. Most importantly, the resource reports rarely investigate the cumulative land cover change impacts of multiple concurrent pipeline proposals on watersheds or sensitive land resources. We note that the environmental analyses prepared for many of these analyses were published prior to updated FERC guidance [2] that clarifies instructions for assessing cumulative impacts.[2] In this analysis, we investigate the combined land cover change of eight proposed pipelines within the boundaries of the Delaware River Basin (DRB).

The Delaware River drains an area of 13,000 square miles, and its watershed (i.e., the DRB) spans portions of Pennsylvania, New Jersey, and Delaware. The river itself, 330

[2] Guidance for the FERC environmental review process was updated in December 2015, after the majority of the analysis for this report was completed. The guidance clarifies cumulative impact as the "the impact on the environment which results from the incremental impact of the action [being studied] when added to other past, present, and reasonably foreseeable future actions…", and further notes that the geographic area to be examined should be specific and relevant to each resource category examined (e.g. land and water, air, cultural resources, etc.).

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miles long, forms the border between Pennsylvania and New Jersey, and empties into the Delaware Bay, which separates Delaware and New Jersey. The DRB is the source of drinking water for roughly eight million people living within the basin, and roughly an equal number outside who receive water transferred from the basin [13]. Much of the basin has exceptional water quality in part due to the over five million acres (7,800 square miles) of forest and wetlands. The forests have been estimated to provide roughly $2,000 per acre per year (in 2010 dollars) in ecosystem service benefits such as water treatment, air pollution removal, and carbon sequestration, and the wetlands as much as $13,000 per acre. Another 4,500 square miles is used for agriculture, which is responsible for roughly $3.5 billion per year in revenue from farm products [14]. Land cover changes have the potential to degrade some of these benefits either directly (conversion to other land uses) or indirectly (e.g., pollutant runoff or fragmentation).

This study does not examine loss of these benefits in detail or the ultimate environmental outcomes from pipeline development, but these consequences establish the rationale for investigating the land cover changes. This study aims to provide credible estimates of the area of land cover changes associated with the eight transmission pipeline proposals.

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Methodology

In this study, we use Geographic Information Systems (GIS) methods to generate estimates of land cover change using spatially referenced pipeline route information (existing and proposed) and baseline land cover data. The goal of this methodology is to develop cumulative projections of land cover disturbance impacts for eight proposed pipeline projects that are currently anticipated to cross through the DRB. The primary metric of interest is the affected land area that is newly "disturbed" (i.e. converted from an existing non-pipeline related land use) within the pipeline projects' construction or permanent ROW, exclusive of area already within existing pipelines' ROW.

Pipelines and Data Sources

Table 1 lists the eight pipeline projects included in this study. The most important data source for this analysis is pipeline route information. The primary source of pipeline route information was commercially available U.S. oil and gas pipeline facilities data purchased from IHS [15], which includes GIS data for both active and proposed pipelines. The IHS data includes route information for all of the pipeline projects except the Southern Reliability Link, and Penn East Pipeline project. The quality of the IHS data for the majority of pipeline routes is rated as "Excellent" (accurate within 50 feet), with the remainder rated as "Very Good" (50–300 feet), or "Good" (301–500 feet). The pipeline route information as purchased was current through the end of 2014.

We verified route information for all pipelines using other data sources. These sources include a GIS geodatabase provided by the Clean Air Council [16], which included preliminary route information for the Southern Reliability Link and Penn East Pipeline project (quality estimated as "Very Good"). In addition, we used maps available in FERC documents and from project proponent reports and websites. We projected digital versions of these maps into ArcGIS 10.2 in order to compare them with the geo-referenced pipeline route features. We also used these maps to update the route information when the route had changed during the course of the project planning. Table 1 includes references to the documents and maps from which we acquired all pipeline information used in this study.

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Table 1. Proposed pipeline projects included in this study

	Pipeline Project	Proponent	Details /Segments	Length in DRB [mi]	Sources*
1	Constitution Pipeline	Williams		13.5	[17-19]
2	Diamond East Project	Williams		56.8	[15]
3	Leidy SE Project	Williams	Franklin Loop	11.2	[20-21]
4	Mariner East[a]	Sunoco Logistics	Mariner East 1, Mariner East 2	49.9 49.8	[22-23]
5	Southern Reliability Link[b]	NJ Natural Gas		18.2	[24-25]
6	PennEast Pipeline	PennEast Pipeline Co.		100.9	[26-29]
7	TEAM 2014 Expansion Project	Spectra Energy	Bernville Loop	5.6	[30]
8	East Side Expansion Project	Columbia Pipeline Group	NJ Loop 10345, PA Loop 1278	7.4 8.8	[31-37]
	Total			**322.2**	

* Sources common to several pipelines: [15-16]; [a] – transports other petroleum products; [b] – Not an interstate pipeline.

For the PennEast project, we used detailed project maps [29] (last updated July 22, 2015) as the primary data source and digitized the pipeline features over the entire project length.

We note that pipeline routes can and do change during project planning, and even construction. We have attempted to include the most recent preferred project routing available from the listed data sources as of September 30, 2015.

In addition to the pipeline route information, we also acquired land cover data. For this study, we used the National Land Cover Dataset (NLCD), 2011 version [38], for the states of New York, New Jersey, and the Commonwealth of Pennsylvania. This data is available as a raster data type, with a spatial resolution of 30 meters. Land cover types are distinguished by numeric codes. For this analysis, we combined some of the land cover types into larger groupings for simplicity. Table 2 shows these groupings. For example, three different forest types are combined into the "Forest" grouping.

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Table 2. Land cover groupings by 2011 National Land Cover Dataset classifications

Grouping	NLCD Classifications Included
Forest	41 – Deciduous Forest; 42 – Evergreen Forest; 43 – Mixed Forest
Wetland	90 – Woody Wetlands; 95 – Emergent Herbaceous Wetlands
Agriculture (Ag) – Pasture	81 – Pasture/Hay
Ag - Cultivated	82 – Cultivated Crops
Grassland/Shrub	71 – Grassland Herbaceous; 52- Shrub/Scrub
Open Space	21 – Developed Open Space; 31 – Barren Land
Developed	22 – Developed Low Intensity; 23- Developed Medium Intensity; 24 – Developed High Intensity
Water	11 – Open Water

Source: [39]

Figure 1 shows an overview map of the study area with the route information for the proposed pipelines overlaid on the NLCD 2011 land cover raster. In addition, the DRB boundary, county boundaries, and existing pipeline routes are shown for reference.

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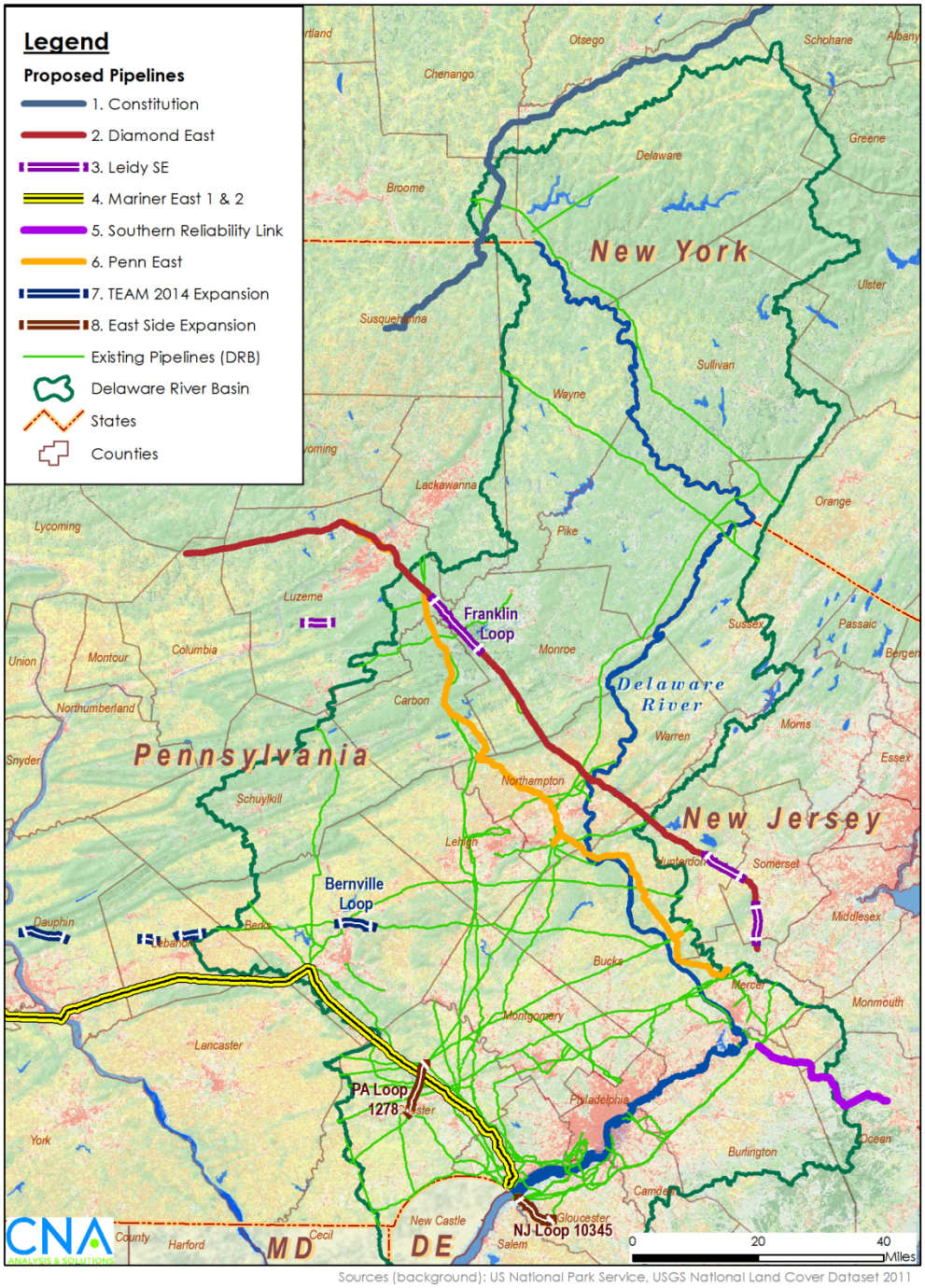
Figure 1. Map of proposed pipelines within the Delaware River Basin



Source: CNA; [15-17, 19, 24-26, 29, 31-32]

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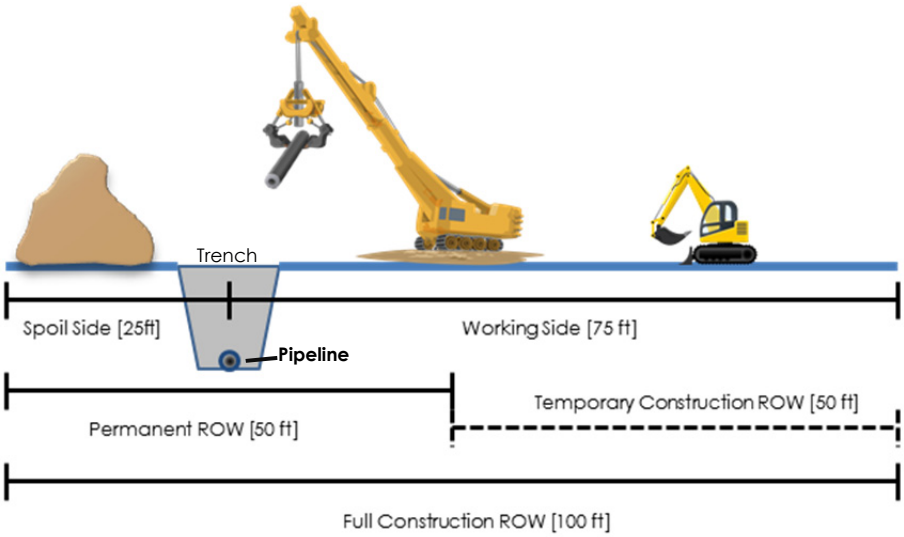
Right-of-Way Assumptions

Construction and Permanent Rights-of-Way

This analysis focuses primarily on the land disturbance required for pipeline development, which includes both permanent land use change impacts and additional disturbance during construction. For the purpose of this analysis, we define the permanent land cover change area as the new permanent right-of-way of the pipeline exclusive of existing permanent right-of-way shared by adjacent pipelines. The land cover change area during construction includes the new permanent right-of-way and additional temporary work space associated with construction, but excludes existing permanent right-of-way shared by adjacent pipelines. The FERC filings and other documents released by the project proponents differ in their presentation and description of these areas. In this study, "New Permanent ROW" is new area cleared for the permanent right-of-way, and "Construction ROW" is total area cleared during construction, inclusive of the New Permanent ROW. The temporary workspace may be inferred by subtraction. See Figure 2 for an illustration of typical ROWs for pipeline construction.

This analysis is limited to the direct pipeline ROWs and construction areas, and does not include additional land area needed for pipeline facilities (e.g. launchers, pump stations, etc.), access roads, or temporary equipment storage areas.

Figure 2. Typical pipeline rights-of-way illustration



Source: CNA; Clip art: clker.com, openclipart.org, office.com

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Greenfield Construction

Greenfield construction refers to pipeline construction through areas where no existing pipelines or rights-of-way are present. The entire operation requires new clearing for construction and operation.

When new pipelines are constructed outside of existing ROWs, a new permanent easement is created, and additional land is usually needed for construction. In general, construction ROWs are divided into a spoil side (area for storing soil and materials excavated from, or used for, backfilling the trench) and a larger working side for moving equipment, and aligning and connecting the pipeline itself before lowering into the trench.

The size of the construction area can vary depending on the type of terrain crossed. In wetlands or core forest areas, the construction ROW can be reduced to limit impacts. In urban or suburban areas, construction ROW may need to be reduced to avoid existing buildings, property lines, or utility infrastructure. In agricultural areas, sometimes a larger right-of-way is needed so that agricultural land can be quickly returned to productive use after construction. The additional area is needed to store the agricultural top soil that is removed during construction so that it can be replaced later, when the construction right-of-way returns to agricultural use.

Adjacent to Existing Rights-of-Way

Pipelines are often routed adjacent to existing pipelines to minimize new clearing and costs of purchasing new easements. Looping projects are nearly always adjacent to the existing pipeline, but new pipelines may also run adjacent to existing pipelines, where possible, to reduce land disturbance impacts and costs. While some additional right-of-way is typically needed, the pipeline itself can often be laid within or very close to the existing permanent easement of another pipeline. That is, the spacing between pipelines can be reduced so that each pipeline does not need its own (typically 50-foot) full permanent right-of-way. When the existing and new pipelines have different owners, a new permanent ROW is generally required even when the routes are adjacent.

In general, it appears that the existing ROW of the adjacent existing pipeline is used as the spoil side of the construction right-of-way for the new pipeline. The wider working side of the construction ROW generally requires new clearing, so as to limit potential damage to existing pipelines due to the movement of heavy equipment.

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Typical Right-of-Way Widths

Our default assumption for the typical ROW width is 50 feet for the permanent easement and 100 feet for the total construction ROW. In this analysis, we analyze both a simplistic symmetric case with equal width on either side of the pipeline, and a more realistic case where the construction ROW is split asymmetrically across the pipeline. The rest of the section documents the assumption when an asymmetric ROW is used.

In greenfield construction, we assume the typical construction ROW is split into a 25-foot spoil side, and a 75-foot working side, with the outer 50 feet being temporary workspace, and 25 feet on either side of the pipeline as permanent easement (see Figure 2). For looping projects or pipelines adjacent to existing pipelines, we assume up to 25 feet of shared right-of-way on the spoil side. Thus, in the case that shared right-of-way is 25 feet, the new disturbance ROW width (all on the working side) is 25 feet for permanent right-of-way and 75 feet for construction ROW. Based on the location of the adjacent pipelines, we varied the amount of shared ROW between 10 and 25 feet. Accordingly, we reduced the spoil side width for construction between 0 and 15 feet, meaning that the new permanent ROW is between 25 and 40 feet in width (instead of 500 feet for greenfield projects). In situations when the proposed project pipeline route diverged from the path of the existing pipelines, we treated it as greenfield construction. Table 3 displays the default ROW widths we used in this study. Several of the pipelines have specific ROW widths specified by land cover type in their project documentation, including the PennEast and Constitution projects.

Table 3. Assumptions for right-of-way widths

Pipeline/ Construction method	**Permanent ROW [ft]**	**Construction ROW [ft]**				
		Spoil side	Working-General	Working-Ag	Working-Wetland	Working-Forest
Greenfield:						
Default	50	25	75	100	50	
PennEast	50	35	65	90	40	
Constitution	50	30	80	95	45	70
Looping:						
Default	25-40	0 - 15	75	100	50	

We used best professional judgment to determine on which side the spoil side and working side will fall, based on the route and location of other pipelines and infrastructure.

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In cases where pipeline documentation specified techniques to reduce pipeline impacts, we attempted to replicate these using mile markers and other notes on construction methods as a guide.[3]

To check the validity of these assumptions, we calculated the implied average width for several pipeline segments using length and disturbance area reported in the FERC or project proponent documentation [17, 27, 33, 37]. Table 4 displays the relevant average ROW width for six pipeline segments, which was computed simply by dividing reported disturbance area for various types of ROW by pipeline length.

Table 4. Average width of pipeline ROWs based on reported disturbance area and pipeline length

			Average ROW Width [ft]			
Pipeline Project	**Segment**	**Length** [mi]	New Perm.	Const. Temp.	Const. Total (new)	W/in Existing
East Side Expansion[a]	Loop 10345 NJ	7.41	26.5	50.2	76.8	~25
East Side Expansion[a]	Loop 1278 PA	8.93	25.5	56.2	81.7	~25
Leidy SE[a]	Franklin Loop	11.47	26.0	30.0	55.9	45.0
TEAM 2014[a]	Bernville Loop	5.60	24.0	75.3	99.3	63.2
Constitution[b]	Broome County	16.85	45.9	57.8	103.7	
PennEast[b]	Entire	110.60	58.6	71.5	130.2	

Sources: [17, 27, 33, 37]

a. Looping project, or adjacent to existing pipeline ROW.

b. New "greenfield" construction project.

Based on Table 4, our assumptions for right-of-way width seem reasonable. The average new permanent ROW ("New Perm.") width for the four looping projects is 25.5 feet, and the temporary construction ROW ("Const. Temp.") width is 52.9 feet, for a construction total ROW of 78.4 feet of new clearing. So in general it is valid to assume that looping projects save roughly 25 feet of clearing width by using existing ROW on the spoil side during construction and sharing permanent ROW.

The new construction projects average 52.3 feet for new permanent ROW width, and an additional 64.6 feet for temporary construction ROW. Although the PennEast

[3] For example, for horizontal directional drilling (HDD), we assumed a permanent ROW of 10 feet (to protect the pipeline) but no construction ROW over the drilled segment. We assumed a 250-by-200-foot drilling pad at the start and end of the HDD sections during construction.

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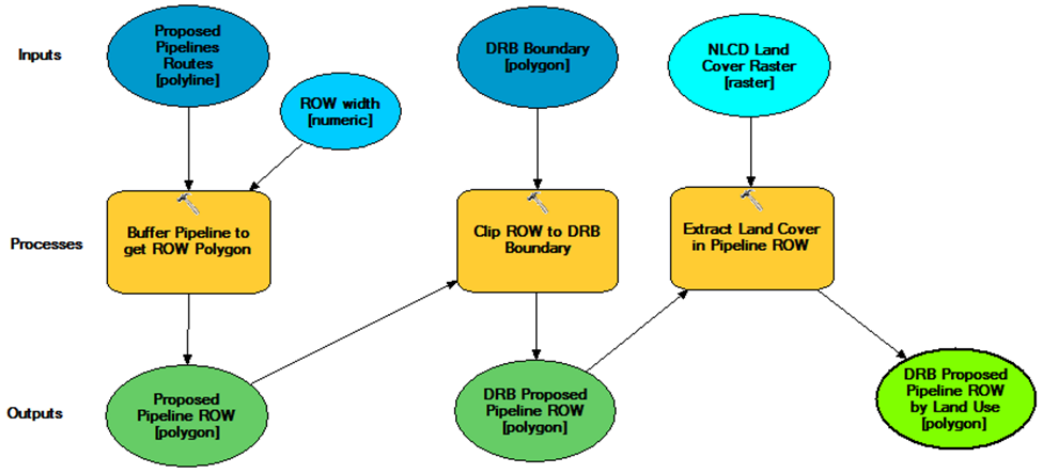
appears to run adjacent to several existing pipelines for portions of its length, the reported areas in the PennEast project documentation [27] (and the calculated average widths) seem to suggest that a full-width permanent easement will be needed along its entire length. This may reflect the fact that PennEast will have a different proponent than the adjacent pipelines, and therefore will need its own easement.

GIS Methods

The land cover analysis for pipelines involves two major steps: (1) converting pipeline route information (in line format) to right-of-way area (in polygon format), and (2) extracting land use types that fall within the right-of-way polygon. In Figure 3, we illustrate the general GIS methodology used for this analysis, including the inputs, processes, and outputs. The major inputs are the pipeline routes, DRB boundary, the NLCD 2011 raster, and the desired ROW width. GIS data types are shown in brackets. We performed additional post-processing as necessary to analyze the results at the county and watershed level.

Figure 3. Generalized GIS process for identifying land use breakdown within proposed pipeline right-of-way



Source: CNA, created with ESRI ArcGIS 10.2 ModelBuilder.

The actual process is slightly more complicated, and requires more steps to extract values from the NLCD raster over the correct domain and convert to a polygon data type. The process as shown can be used only for a symmetrical buffer about the pipeline, which is suitable for analyzing the permanent right-of-way, but not ideal for analyzing the construction ROW, which is typically asymmetric.

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As a result, we used two separate methodologies - asymmetric buffering and symmetric buffering - to estimate the new disturbance caused by pipelines. The asymmetric method cuts the pipelines into segments, and uses two fields of the attribute table to create independent buffers on the left side, and then the right side of the feature. This permits setting the left and right side buffers to different values, allowing for an asymmetric simulated ROW. We adjusted the relevant right or left buffer width for each segment to account for shared rights-of-way with existing pipelines. For example, for an existing pipeline located 25 feet to the topographic left of the proposed pipeline, we would set the left buffer distance to zero instead of the typical 25 feet because there would no 'new' clearing needed.

The symmetric method uses a single entered value (e.g., 25 feet) to buffer a constant distance from the pipeline, which results in a symmetric ROW with a width of twice the entered value. We excluded the rights-of-way for existing pipelines by creating buffers (assuming a 50-foot permanent ROW) around the existing pipelines, and "erased" that area from the proposed pipeline ROW.

We also performed a third analysis based on the symmetric methodology to determine the total land disturbance for full-width ROWs with no exclusions for existing pipelines. We did not erase the existing pipeline ROWs in this case.

Table 5 describes these three methodologies in more detail. Figure 4 shows an illustration of the differences between the methodologies, including differences in handling cases involving shared ROWs with existing pipeline projects. The figure illustrates how the ROW is computed for both greenfield construction (top), and construction adjacent to existing ROWs (bottom).

In all three cases, we performed the analysis twice; first, we used smaller buffers for the permanent ROW, and then larger buffers for the construction ROW. Table 3 displays the assumed widths for these ROW cases.

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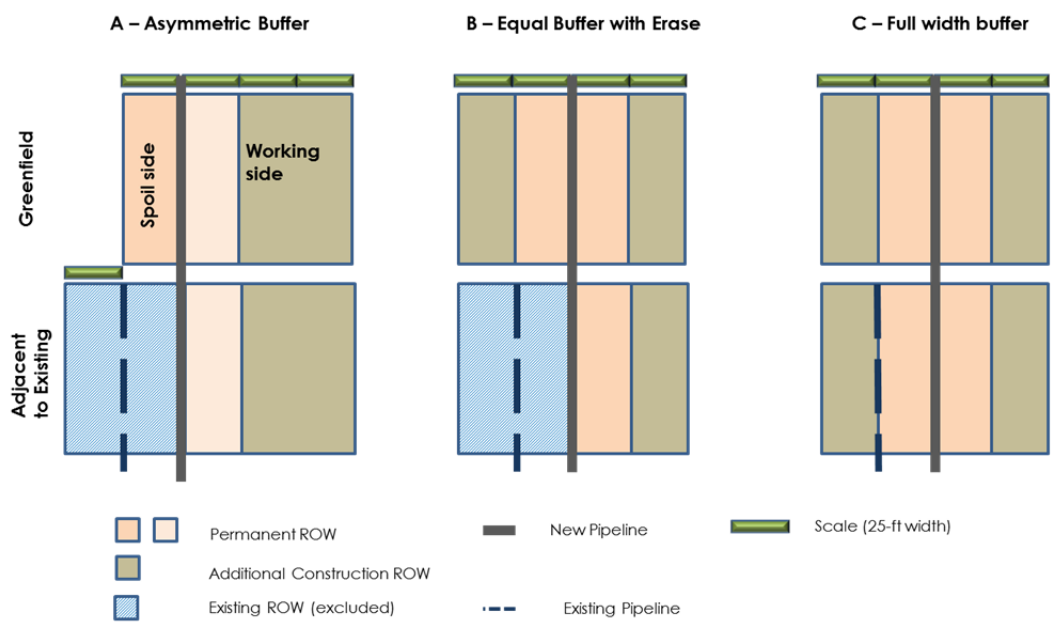
Table 5. Methods for estimating land use area impacts of proposed pipelines

Method	Name	Description
A	Asymmetric Buffer	Divide all pipelines into segments, and enter a buffer distance for the topographic left and right side of the feature. Adjust buffer width to account for different land use types and existing ROWs. In addition, account for special cases such as HDD and encroachments.
B	Equal Buffer with Erase	Buffer the proposed pipeline by a constant width (equating to either permanent or construction ROW), symmetric about the pipeline. In GIS, also buffer all existing pipeline features to account for a 50-ft permanent right-of-way. Use the Erase tool in GIS to remove the existing ROW area from the proposed ROW area.
C	Full-width buffer	Buffer the proposed pipeline by a constant width (equating to either permanent or construction ROW), symmetric about the pipeline.

Figure 4. GIS methodology illustration for the three area impact calculation methods for both greenfield construction (top), and construction adjacent to existing ROWs (bottom).



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Estimation of Total Forest Area Impact

While this study investigates land cover disturbance for the entire range of land cover types in the NLCD, a particular metric of interest is the total direct forest area impact for the entire Delaware River Basin. (This study does not examine indirect effects such as loss of core forest area due to new forest edges.) We first calculate the forest area impact based on the GIS methodology described, but we recognize some limitations posed by using the NLCD raster. Namely, the coarseness of the NLCD and issues with assignment of land cover types could lead to errors for an individual land use type such as forests. Specifically, we have observed that existing pipeline rights-of-way are often classified as forest (instead of grassland or developed/open space), which may slightly over-estimate forest area. To a lesser extent, low-density residential (or agricultural) land with some tree canopy may also be classified as forest. The 30-meter resolution (cell size) of the NLCD may also come into play, as each cell is slightly wider than the typical construction ROW, and the land cover type may not be completely homogenous within the cell.

In order to correct potential errors in forest area, we validate our GIS results against forest area impacts reported in the FERC or pipeline proponent documentation, which should be more accurate due to greater precision of right-of-way limits and possibly more precise land cover data. Through comparison of these two forest area estimates, we generate adjustment factors that can be used to compute a refined estimate of forest area impacts for the whole basin based on the GIS results. The next section, particularly Table 6, explains the validation process for the forest areas, and presents the adjustment factors we use to compute the best estimate of total forest area impact.

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Results

This section presents results of the land cover disturbance analysis. We first present a validation of the methodology. Then we present the total land disturbance area within the DRB for both permanent ROWs and construction ROWs, followed by more granular results by pipeline, by county, and by watershed. Finally, we present our own calculations of the total number of stream and waterbody crossings.

Validation

We validated our GIS methodology by comparing estimates of new pipeline impact by land use to similar estimates in the FERC documentation. All of the GIS estimates used for validation were generated using the "A – Asymmetric Buffer" methodology (see Table 5). We focused on pipelines with disturbance area broken out by land cover type in the documentation, and with pipeline segments within the DRB. Three pipeline projects had segments entirely within the DRB with detailed land cover impact estimates: the Leidy SE Franklin Loop, the TEAM 2014 Bernville Loop, and the two loops in the East Side expansion project. While these projects all fit these criteria, they are also primarily looping projects. Thus we also included the Broome County section of the Constitution pipeline, which is mostly within the DRB, in order to check the methodology on a primarily greenfield construction project.

For validation, we elected to compare the new area impacted for forest, and for all land cover types. Table 6 displays the validation results for forest area impact, and Table 7 for total area impact (all land cover types). The definitions of land cover class groupings for computation of area impact varied by pipeline project. In some cases, the existing right-of-way area was not separated from the total impact area. Generally, the "Open Space" land cover type included the existing pipeline ROW areas. In these cases, we left out the "Open Space" land cover type (where existing ROW area was included in the documentation) from the total. We have denoted the projects to which this assumption was applied with an asterisk. We analyzed the impacts using all the remaining land cover types.

Generally, our GIS estimates of forest disturbance are about 25 percent high for permanent ROW, and 13 percent high for construction ROW as compared to the pipeline documentation. By contrast, GIS estimates of total disturbance are about 5

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percent high for permanent ROW and 3 percent low for construction ROW, which amounts to an overall average error of 1.5 percent high.

Table 6. Validation of new forest disturbance [ac] from pipeline documentation ("Document") versus GIS estimates for the permanent and construction ROWs

	New Permanent ROW			Construction ROW		
Pipeline Project	Document [ac]	GIS [ac]	Error [%]	Document [ac]	GIS [ac]	Error [%}
Leidy SE - Franklin	14.9	21.9	47.5%	42.6	51.8	21.5%
TEAM 2014- Bernville	5.9	6.7	13.6%	22.6	26.3	16.6%
East Side - NJ				10.3	3.0	-70.8%
East Side - PA				21.4	25.0	16.9%
Constitution (Broome County)	47.5	56.6	19.1%	98.5	114.3	16.0%
Median			19.1%			16.6%
Weighted Average	**68.3**	**85.2**	**24.8%**	**195.5**	**220.5**	**12.8%**

Table 7. Validation of total new disturbance area [ac] from pipeline documentation ("Document") versus GIS estimates for the permanent and construction ROWs

	New Permanent ROW			Construction ROW		
Pipeline Project	Document [ac]	GIS [ac]	Error [%]	Document [ac]	GIS [ac]	Error [%]
Leidy SE - Franklin	36.1	33.9	-6.0%	77.7	75.6	-2.7%
TEAM 2014 - Bernville *	16.4	18.4	12.0%	69.7	61.5	-11.7%
East Side - NJ *				65.5	65.2	-0.3%
East Side - PA *				89.7	82.7	-19.4%
Constitution (Broome County)	93.4	100.9	8.0%	211.1	211.7	0.3%
Median			8.0%			-2.7%
Weighted Average	**145.9**	**153.2**	**5.0%**	**513.6**	**496.8**	**-3.3%**

* Open Space excluded from calculations because pipeline documentation does not distinguish open space in existing ROWs from new open space impacts.

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Land Cover Distribution near Pipelines

Land cover disturbance area estimates could theoretically be sensitive to small errors or potential changes in pipeline route information. It is common that pipelines may have small shifts in routing all the way through construction. For instance, the PennEast pipeline has a 400-foot right-of-way "study area" to account for some of these potential shifts in the final route [26]. In addition, the GIS pipeline route data on which we based this analysis was of varying spatial accuracy (generally within 50 feet, but occasionally only within 300–500 feet).

Before investigating the new disturbance areas within the pipeline ROWs only, we investigated the sensitivity of the land cover impact area to uncertainty in pipeline route. To do so, we computed the land cover characteristics of the larger areas in successively wider 'corridors' around proposed pipeline routes. Here we assume a symmetric buffer and we don't exclude existing ROW, so the calculation method is method C (see Table 5).

We examined the land cover distribution as a function of distance from the proposed route by progressively increasing the buffer width from the pipeline. If the distribution does not change as the buffer distance increases, we can be reasonably confident that the errors associated with route uncertainty are relatively small. If the relative proportions of a given land use change as the buffer distance (i.e. ROW width) increases, then pipeline siting may be effectively avoiding (or targeting) certain types of land uses. Plotting the areas of disturbance versus pipeline ROW width also gives an idea of the general makeup of the land cover in the neighborhood of pipelines.

We first investigated the area very close to the pipeline at several ROW widths, including 10 feet (minimum in areas such as wetlands), 30 feet (typical cleared ROW width in the permanent easement), 50 feet (typical permanent easement), and 100 feet (typical construction easement).

Figure 5 displays these results, which do not exclude existing ROW, and so is not solely new disturbance area. Figure 6 displays the results for larger buffer distances (up to a width of 400 feet) on a continuous stacked area plot. For each land cover type, the increase is nearly linear.

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Figure 5. Land cover disturbance area for typical ROW widths for the 8 proposed pipeline projects

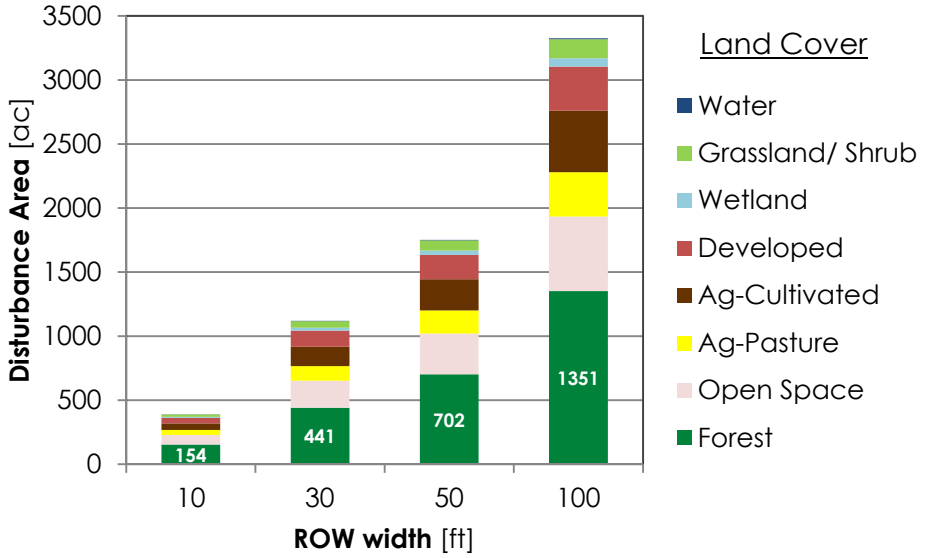
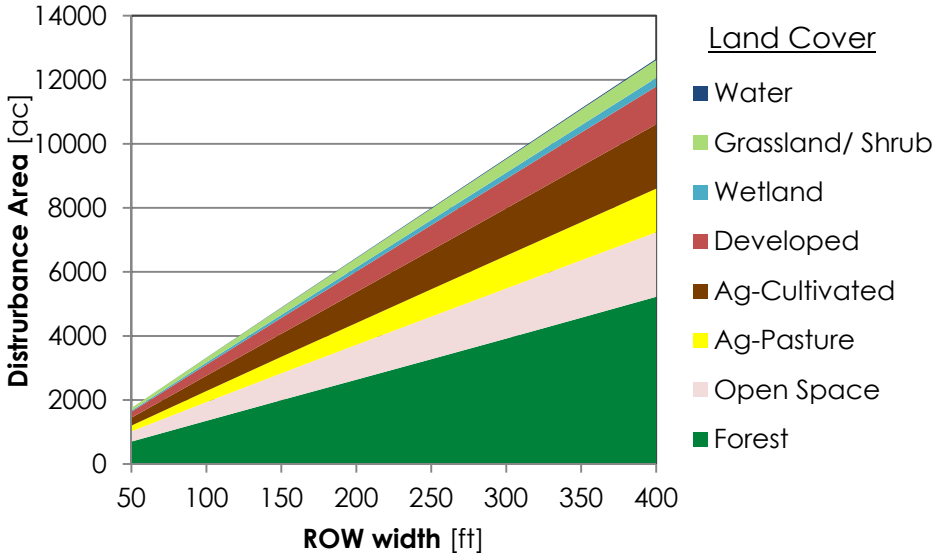


Figure 6. Disturbance area by land cover type versus theoretical ROW buffer width for the 8 pipelines examined in the DRB



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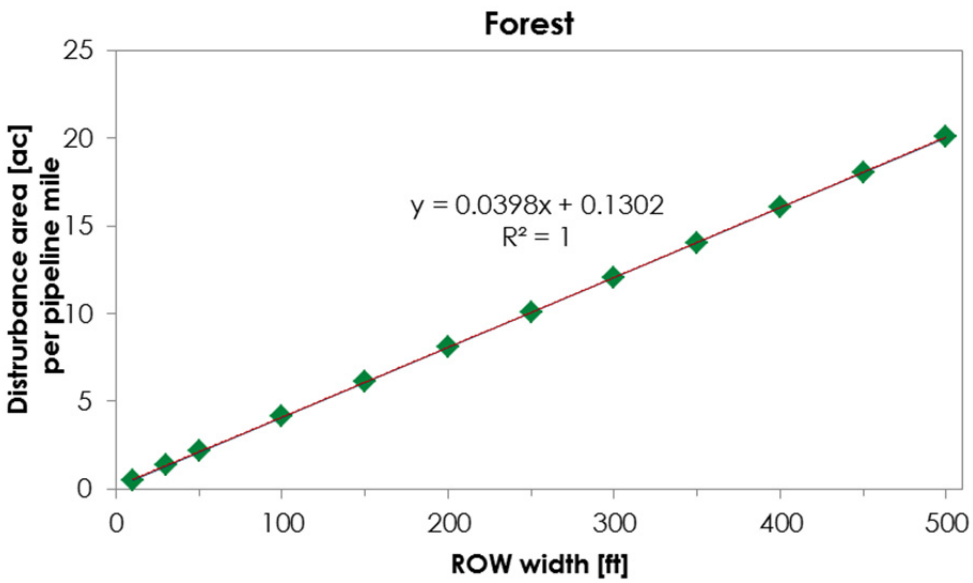
We can check these results to see whether the increase in area versus increase in ROW width for particular land use types is truly linear. First we analyze forest impacts. Figure 7 shows the amount of forest area affected versus pipeline ROW width. In this case, the forest area is normalized to the pipeline length, so the vertical axis shows impacted acreage per mile of pipeline. The figure demonstrates that the trend is very much linear. By fitting a trendline to the data, we generate a useful equation that gives the expected forest area impacted per mile for each additional foot of pipeline ROW width. In this case, the slope of the trendline indicates that, on average, each mile of new pipeline in the DRB will affect 0.04 acres of forest for each foot of ROW width. So a 50-foot ROW will affect roughly two acres of forest per mile.

Figure 7. As ROW width increases, forest area impacts increase in a linear fashion.



Many of the other land cover types show a similar pattern. For wetlands, the trend is nearly linear (see Figure 8). Based on this analysis, the slope of the trendline indicates that, on average, each mile of new pipeline in the DRB will affect 0.002 acres of wetland for each foot of ROW width. So, a 50-foot ROW will affect roughly 0.1 acres of wetland per mile on average.

The equations presented here can provide a useful means for generating an initial estimate of the potential impact from pipeline development in the DRB if no information is known about the specific route. Though we add the caveat that the relationships are based on the eight pipeline projects we examined. A more localized analysis would then be needed to generate more refined estimates of the impacts for a specific pipeline project once the route is known.

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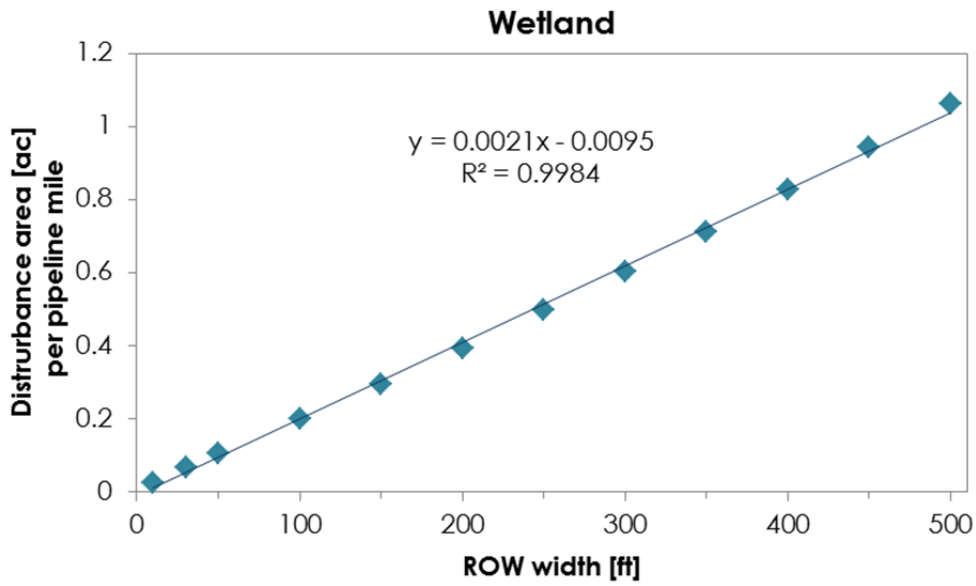
Figure 8. As ROW width increases, the increase in wetland impact area is nearly linear



Land Cover Impact in the DRB

Figure 9 displays the total new disturbance area in the DRB associated with ROW construction for the eight proposed pipelines projects. The results for the new permanent ROW are shown on the left, and the construction ROW on the right, each computed via three separate methodologies (refer to Table 5). Labels on the graph display the forest area impacted and total area impacted for each methodology.

Method A is the best estimate using asymmetric buffers, and excluding existing ROW. Method B is the symmetric buffer method excluding existing ROW. Method C is the symmetric buffer method with no exclusions. The forest impact area and total area in acres are labeled on the chart. We note that the computations for Methods A and B are very similar for the permanent ROW, but are different for the construction ROW. This is likely due to the fact that the asymmetric buffer used for Method A would create less overlap with existing ROW than the symmetric buffer method used in Method B. Method C does not exclude any existing ROW, and is unsurprisingly the highest estimate.

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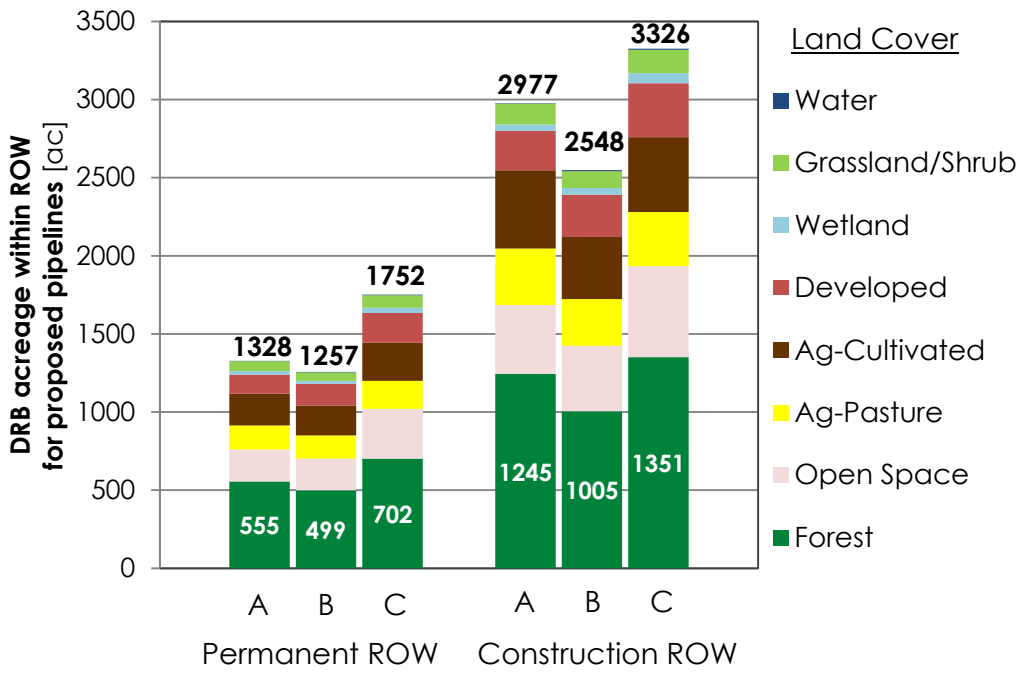
Figure 9. Total disturbance areas in the DRB for the permanent and construction ROWs for the proposed pipeline as generated by the three GIS methods (A,B, &C) used in this study



Impact by Pipeline

The total new disturbance area can be separated by pipeline only to a limited extent because some of the new pipelines share a ROW for part of their length: For instance, the Diamond East and Leidy SE projects (see Figure 1), which also have the same pipeline proponent. Or the Mariner East and East Side Expansion projects, which intersect each other.

Table 8 displays the estimated disturbance area by pipeline, broken down by land cover type for the new permanent ROW. Table 9 shows the same for the construction ROW. In both cases, the areas shown are the areas only within the DRB. The area calculations reflect the Method A methodology (see Table 5) applied for each pipeline. The total area disturbed by land cover type is shown at the bottom as the sum of the individual pipeline results. This total includes double-counting of some area where the proposed pipeline ROWs cross or are parallel. Hence, we also present the totals for all pipelines computed where all proposed pipeline ROWs are merged

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to avoid double-counting. We observe from the Method A total results (computed with the same methods as the sum of individual pipeline results) that the double-counted area is roughly 18 acres (1346 minus 1328). Results for Methods B and C (see Table 5) are shown for comparison.

Table 8. Estimated disturbance area [ac] within the DRB by pipeline and land cover type for the new permanent ROW

Pipeline	Forest	Wetland	Grassland/Shrub	Ag - Pasture	Ag- Cultivated	Open Land	Developed	Water	Total
Constitution Pipeline	40.7	0.9	1.3	29.0	4.9	3.8	0.1	0.0	**80.8**
Diamond East Project	96.7	6.3	3.7	9.2	23.7	26.6	3.9	0.6	**170.7**
Leidy SE Project	21.9	3.7	3.3	0.3	0.1	4.0	0.1	0.4	**33.9**
Mariner East 1&2	75.5	1.4	16.6	28.2	25.3	76.1	51.7	0.0	**274.9**
NJ Natural Gas Project	7.1	1.4	1.8	4.3	11.3	48.1	36.0	0.0	**110.0**
PennEast Pipeline	311.2	6.6	36.7	72.8	132.3	33.8	14.1	0.4	**607.9**
TEAM 2014 Expansion Proj.	6.7	0.1	0.4	2.5	2.5	2.7	3.3	0.1	**18.4**
East Side Expansion Project	8.6	2.5	2.0	6.8	4.2	12.0	12.9	0.0	**49.0**
NJ Loop 10345	*0.9*	*1.9*	*0.4*	*2.1*	*1.2*	*4.9*	*9.0*	*0.0*	**20.6**
PA Loop 1278	*7.7*	*0.6*	*1.6*	*4.7*	*3.0*	*7.1*	*3.8*	*0.0*	**28.5**
TOTALS - by method									
Sum of Pipeline Results [a]	568	23	66	153	204	207	122	1.5	**1346**
A - Asymmetric buffer	555	22	64	153	204	205	122	1.4	**1328**
B - Symmetric buffer	499	20.2	56.4	149	192	200	137	3.2	**1257**
C - Full symmetric buffer	702	34.3	79.8	180	244	319	189	4.1	**1752**

[a.] "Sum of Pipeline Results" includes some double counting of areas, notably for Mariner East 1 and 2, and Leidy SE, Diamond East, and PennEast.

NOTE: Pipeline results generated using Method A. Totals shown for other methodologies by comparison. Totals may not sum exactly due to rounding.

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Table 9. Estimated disturbance area [ac] within the DRB by pipeline and land cover type for the new construction ROW.

Pipeline	Forest	Wetland	Grassland/Shrub	Ag - Pasture	Ag- Cultivated	Open Land	Developed	Water	Total
Constitution Pipeline	80.8	1.5	2.4	65.0	11.1	8.1	0.4	0.0	**169.3**
Diamond East Project	295.7	15.1	8.0	28.8	71.5	74.4	11.7	2.2	**507.4**
Leidy SE Project	51.8	6.1	5.4	0.9	0.3	10.0	0.3	0.8	**75.6**
Mariner East 1&2	172.0	3.9	39.6	64.7	64.2	160.2	100.9	0.1	**605.7**
Southern Reliability Link	16.2	2.7	3.5	11.4	29.8	83.2	68.0	0.0	**214.7**
PennEast Pipeline	633.3	11.1	71.3	164.3	305.8	70.7	27.9	0.7	**1285.1**
TEAM 2014 Expansion Project	19.7	0.3	0.8	6.4	7.3	6.9	7.4	0.1	**48.9**
East Side Expansion Project	24.8	4.3	5.2	20.1	11.5	34.2	36.5	0.0	**136.6**
NJ Loop 10345	*2.5*	*3.1*	*1.3*	*6.8*	*3.8*	*13.8*	*24.8*	*0.0*	**56.2**
PA Loop 1278	*22.3*	*1.2*	*3.8*	*13.3*	*7.7*	*20.4*	*11.8*	*0.0*	**80.5**
TOTALS - by method									
Sum of Pipeline Results[a]	1294	45	136	362	501	448	253	3.9	**3043**
A - Asymmetric buffer	1245	41	133	361	501	440	253	3.3	**2977**
B - Symmetric buffer	1005	42	112	299	398	414	272	6.6	**2548**
C - Full width symmetric buffer	1351	65	149	344	479	582	344	8.1	**3324**

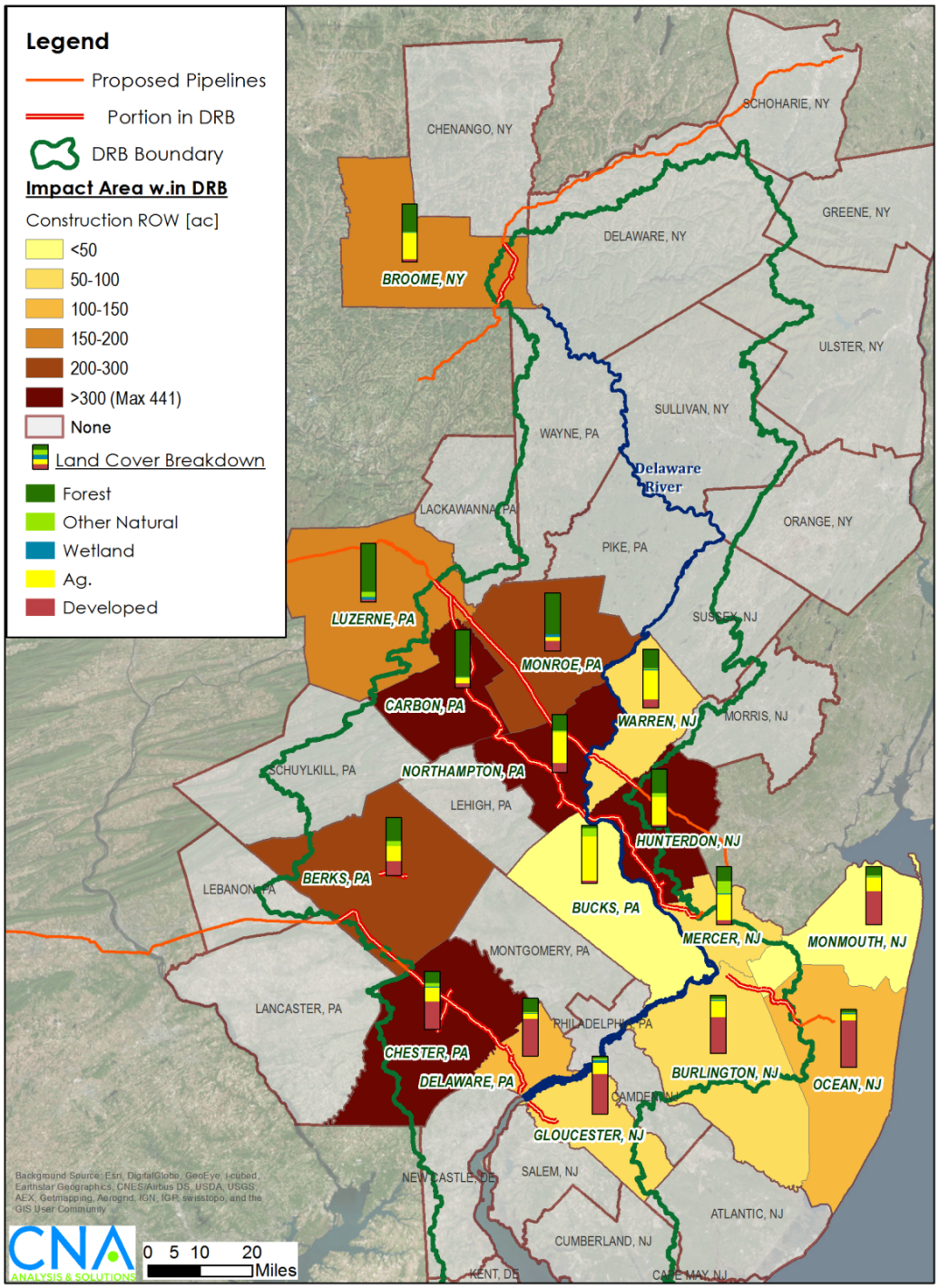
[a.] "Sum of Pipeline Results" includes some double counting of areas, notably for Mariner East 1 and 2, and Leidy SE, Diamond East, and Penn East.

NOTE: Pipeline results generated using Method A. Totals shown for other methodologies by comparison. Totals may not sum exactly due to rounding.

Impact by County

We computed the total area impact by county by intersecting the Method A total impact area in the DRB with county boundaries. Figure 10 maps the construction ROW impact by county. Shading shows the total area impacted by construction ROW within the DRB portion of each county. Stacked bars on the map show the breakdown of the impacted area by land cover type. See Appendix A for the results by county in tabular format. (Table 11 displays the county-level area impact for the new permanent ROW, and Table 12 does so for the construction ROW.)

Figure 10. Land area impacts of proposed pipeline construction within the Delaware River Basin (DRB), by county



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In Figure 9, it appears the impacts will be most concentrated in the central portion of the DRB. Carbon, Monroe, and Hunterdon counties all have in excess of 200 acres of land disturbance, while Northampton has the highest of any county, with 441. These counties also have the largest percentage of the impact affecting forests. For instance, over 75 percent of the total impact area in Luzerne and Carbon counties will be in forests.

The lower portion of the watershed also has a concentration of impacts. Chester and Berks Counties each have over 200 acres affected during construction. The land cover types impacted are distributed more across agriculture, developed land, and forests than in the middle portion of the basin.

Broome is the only county with impacts in the upper basin. The area of impact is roughly evenly divided between forest and agriculture.

Overall, the breakdown of land cover types affected by pipeline development follow the general land cover patterns of the DRB as a whole: predominantly forest in the Upper and Western portions of the basin, more agriculture in the middle and Eastern portions, and finally, much more developed land in the lower portion of the basin.

Impact by Watershed

In addition to analyzing the results by county, we also investigated the results by using hydrographic boundaries. We totaled the results by Hydrologic Unit Code–10 digit (HUC10) watershed using data from the USGS Watershed Boundary Dataset [40]. In Figure 11, we display the results for new permanent ROW area by HUC10 watershed as a stacked bar chart. Figure 12 shows similar results for the new construction ROW. On the left, the HUC10s are grouped by the larger HUC8 watershed subdivision, with the HUC8 names labeled. (Figure 13 shows the spatial location of both the HUC10 and HUC8 boundaries.) The bold number labels on the graph indicate total area impacted in acres. The breakdown of the area by land cover type is shown in a table format in Appendix A (see Table 13 and Table 14).

Figure 13 shows the total new construction ROW area impact on a map instead. (Shading denotes total new construction ROW area [ac] by HUC10 for the proposed pipeline projects.) It is clear from the map that the most area will be affected through the middle portion of the DRB, especially in the Lehigh and Middle Delaware HUC8 watersheds, and to a lesser extent the Schuylkill, Brandywine-Christina, and Lower Delaware watersheds. These areas, especially the Lehigh subbasin, also have the majority of the forest disturbance.

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Figure 11. New permanent ROW land cover breakdown by watershed (HUC10), with grouping by HUC8 watershed name (labels show total impact area)

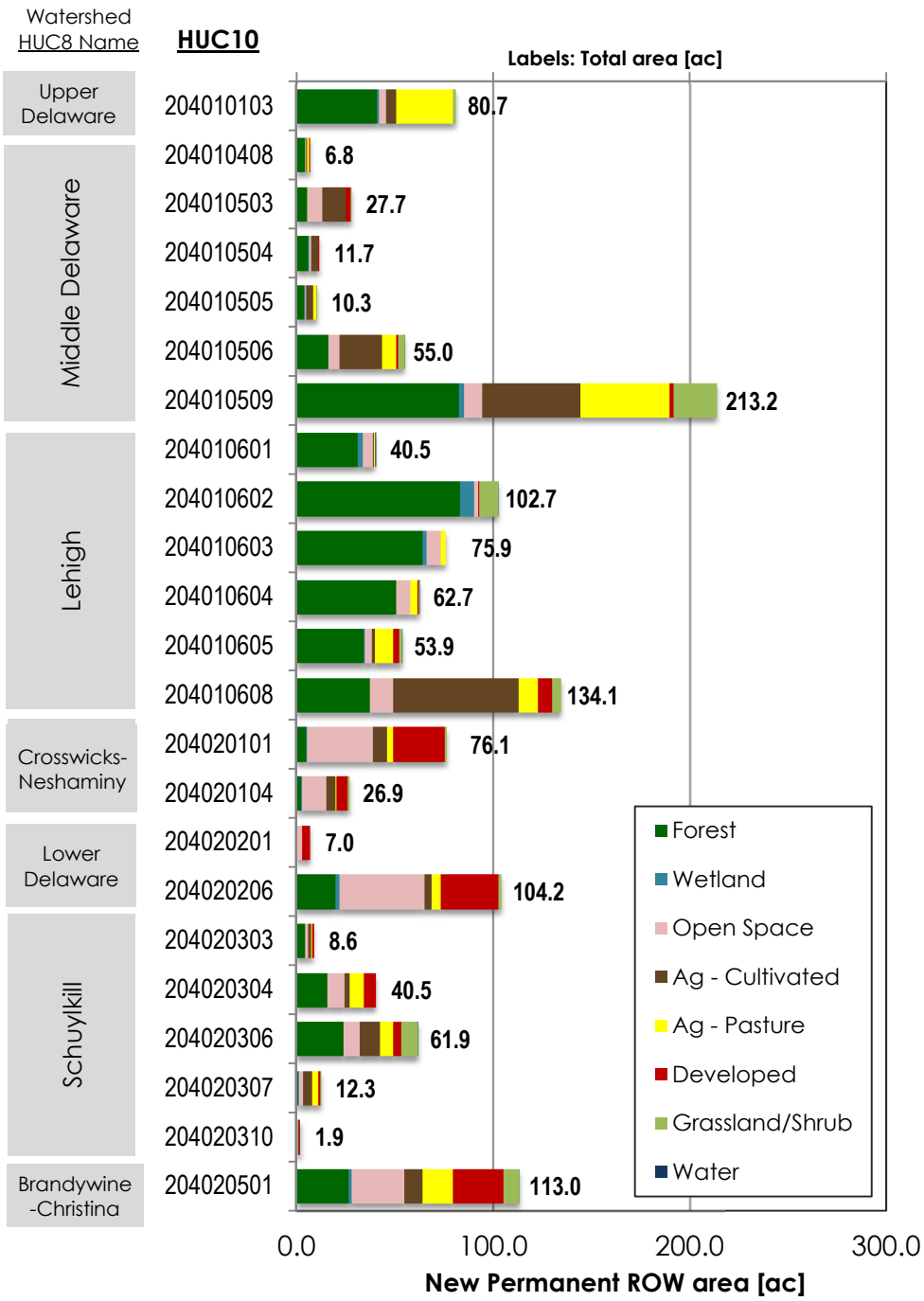

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Figure 12. New construction ROW land cover breakdown by watershed (HUC10), with grouping by HUC8 watershed name (labels show total impact area)

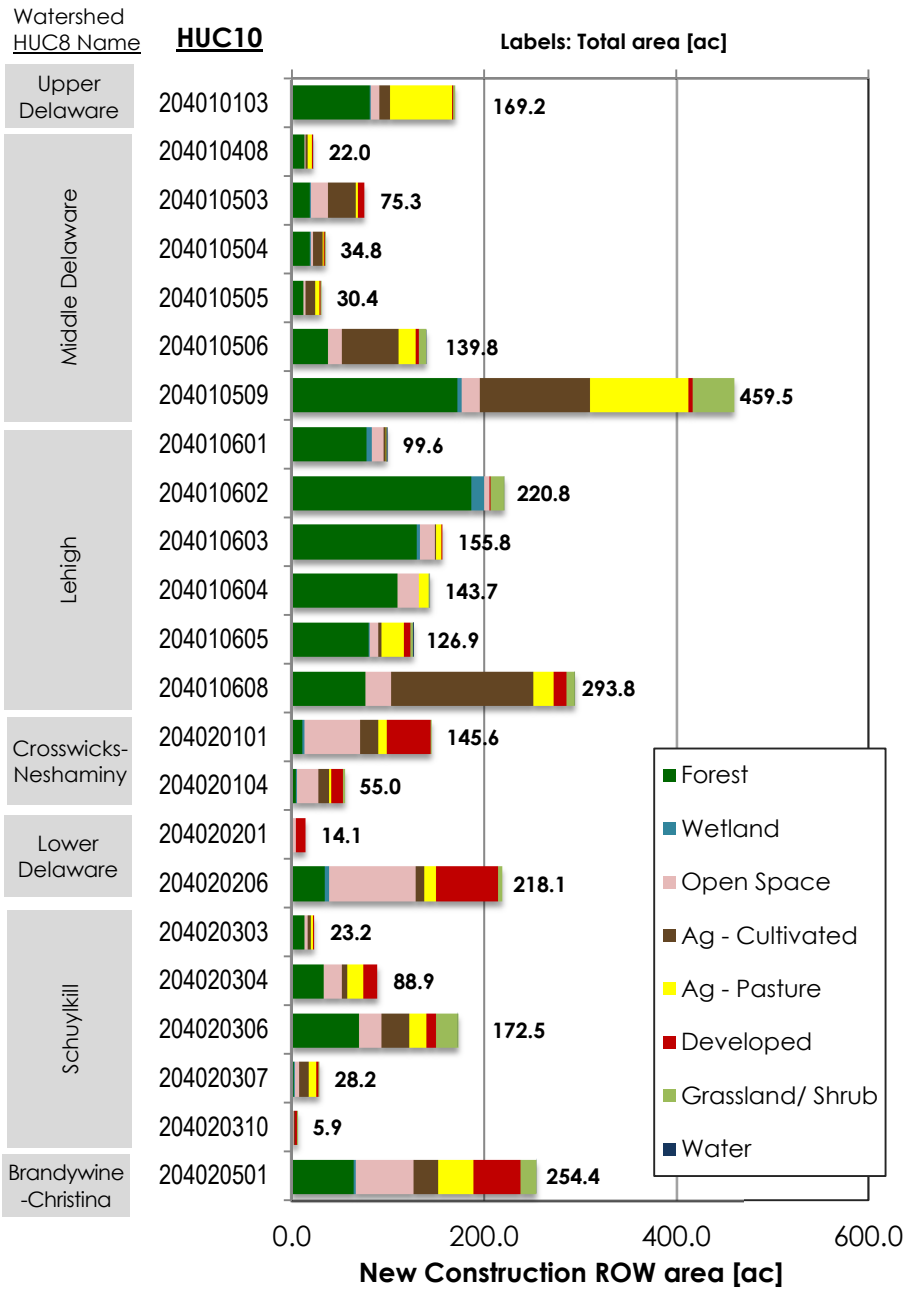

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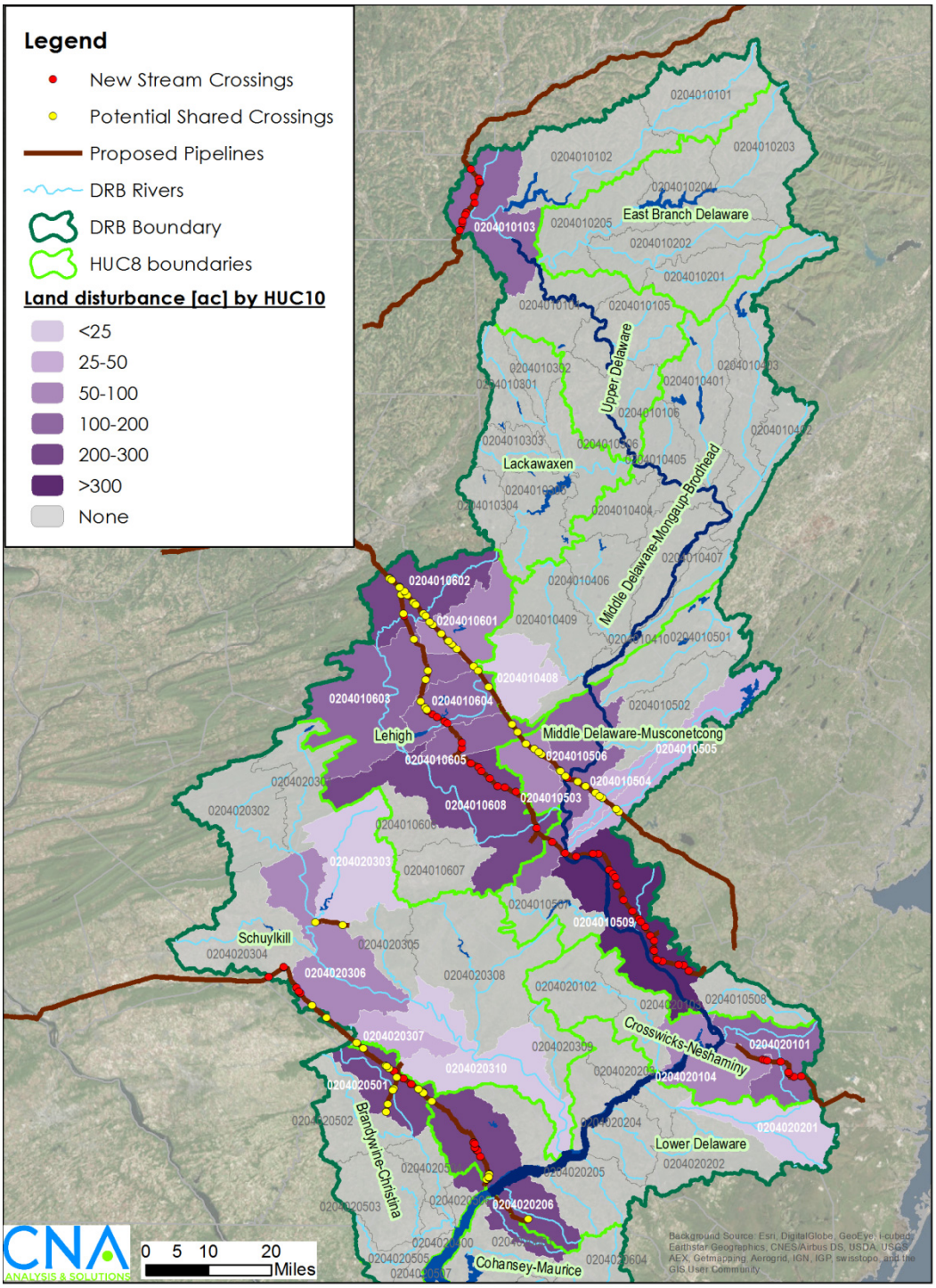
Figure 13. Watershed impacts of pipeline construction – land disturbance and stream crossings (labels show HUC10 numbers)



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Potential Stream Crossings

Stream crossings are a particular area of concern for pipeline development, as land in close proximity to waterways is at high risk for erosion, nutrient export, and potential pollutant export. In addition, any sediment or pollutants that enter the stream will be carried downstream in the waterway.

While the final EIS documents approved by FERC for pipeline projects contain listings of the proposed stream crossings, it is difficult to determine the total number of stream crossings for all eight projects for several reasons. Not all of the pipelines have final EIS documents, and the location of stream crossings is not in a consistent format across the different documents. In some cases, it is difficult to assess whether certain streams are within the Delaware River Basin. For these reasons, we assessed stream crossings using a consistent methodology for all of the proposed pipelines.

We computed the number of stream intersections[4] in GIS using the pipeline route information and the National Hydrography Dataset Plus Version 2 (NHDPlus v2) stream flowlines. The NHDPlus v2 dataset is fairly high resolution (stream segments drain less than one square mile on average in the Delaware River basin), but does not include most intermittent streams or ephemeral streams in the Eastern US.

We also accounted for the possibility that existing stream crossings could be used where proposed pipelines are parallel to existing pipelines. We assumed that when an existing pipeline intersected the stream within 250 feet[5] of the proposed pipeline's crossing, a shared crossing would be used.

Figure 13 shows these intersection points that indicate stream crossings. The yellow points indicate crossings that have some potential to share an existing crossing. The red points indicate "new" crossings that are not adjacent to existing pipeline crossings of streams. Table 15 (in Appendix A) tabulates the intersections by HUC10.

In total, we found 175 potential new crossings, of which 92 have the potential to be "shared" crossings with existing pipelines.

[4] We used the ArcGIS Intersect tool with the pipeline routes and NHDPlus flowlines as inputs (both are polyline datatype), which results in a point file with a point marking each location a stream and a proposed pipeline intersect.

[5] We generated a second set of intersection points using existing pipeline routes and NHDPlus flowlines. Then we computed the number of proposed intersection points falling within 250 feet of these intersections. We chose 250 feet as a generous buffer that can identify potential shared crossings even when the stream line is nearly parallel to the pipeline ROWs.

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This total counts only intersections with streams in the NHDPlus database, and likely dramatically undercounts the total number of stream crossings due to many intermittent and ephemeral streams not included in the database. We note that the environmental assessment documents issued by FERC and the pipeline proponents usually provide a more complete accounting of potential stream crossings, most likely gathered from local field and site analysis. As an example, a permit application to Delaware River Basin Commission for the Mariner East project found over 180 potential stream crossings, the great majority of which are intermittent or ephemeral [23]. Without the ability to do field investigation, or access to much more complete stream data for the entire basin, we were limited to identifying crossings of the predominantly perennial streams in the NHDPlus database.

Best Estimate of Impacts

Forest Area Impacts

The metrics presented in this report present an estimate of the land cover impacts of pipeline construction. The estimates for individual land cover type impacts depend heavily on the accuracy of the pipeline routes, and the accuracy of the NLCD data used. As mentioned previously, we observed that existing pipeline rights-of-way were often classified as forest in the NLCD, which may slightly overestimate forest impact area. To a lesser extent, pipeline routes running through or adjacent to low-density residential (or agricultural) land with some tree canopy may also be classified as forest.

In order to partially account for these potential discrepancies, we used our validation data (refer to Table 6) to develop adjustment factors for forest area impact. We report three key metrics in Table 10, computed in three ways: First, the GIS results for both the construction and permanent ROW areas, computed via the asymmetric method (A). The third metric is the permanently cleared forest area that would be within the permanent ROW, commonly estimated to be 30 feet wide (see, for example, [19]). This metric identifies the forest impact over the longer term, assuming some of the permanent ROW (outside 30 feet) is allowed to regrow, while still leaving the center of the ROW cleared.[6] Since our results show forest area impact scales linearly with ROW width (see Figure 6 and Figure 7), we calculate this

[6] This metric is almost certainly a low estimate of potential impact since many pipeline operators may elect to keep the entire permanent ROW clear. This also does not take into account looping projects where one side of the permanent ROW may be shared with an existing pipeline, and therefore would not be suitable for allowing forest regrowth.

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permanently cleared area by multiplying permanent ROW impact area by the ratio of widths (30/50), or 0.6.

The second and third data columns in Table 10 are computed using two adjustment factors computed from the validation data. The specific adjustment factor uses values specific to the construction and permanent ROWs. The permanent ROW specific adjustment factor used is 0.752, and the construction ROW specific factor is 0.872. The general adjustment factor uses an average, constant adjustment applied to both ROW types.[7] The resulting general adjustment factor used is 0.832, or a 16.8 percent reduction in forest area from GIS results. In all cases, the permanently cleared area estimate is computed by multiplying the permanent ROW estimate by 0.6.

Table 10. Estimated total forest area impact for pipeline ROWs in the DRB by ROW type for the eight proposed pipelines in this study

	DRB Forest Area Impact [ac]				
ROW Type (width)	GIS Results	Adjusted (Specific)	Adjusted (General)	**Adj. Factor** (Specific)	**Adj. Factor** (General)
Construction (~100 ft)	1,245	1,036	1,086	0.872	0.832
Permanent (~50 ft)	555	462	418	0.752	0.832
Permanently cleared (~30ft)	333	277	251	0.6[a]	0.6[a]

[a.] Adjusted by multiplying by Permanent ROW Forest Impact Area

So, in total, we estimate that within the DRB, the eight pipeline projects in this study will impact:

- Approximately 1,040–1,090 acres of forest within construction ROW during construction
- Approximately 420–460 acres of forest that will fall within the proposed pipelines' new permanent ROWs
- Approximately 250–280 acres of forest that will be permanently lost in the cleared area of the pipeline ROWs, if all pipeline projects keep only 30 feet of width in the permanent ROW cleared.

[7] Since we had an unequal number of pipeline validations for the construction and permanent ROW, we computed the general adjustment factor by weighted average of the construction and permanent factors, with the nominal ROW width as the weight. That is, the construction ROW factor had twice the weight as the permanent factor.

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We note that these estimates do not include all potential forest impacts for the pipelines' construction. Typically, pipeline construction requires additional area for pipeline facilities (compressors, pumps, valves, terminals), temporary workspace for equipment storage and staging, as well as access roads to bring equipment and materials to the working ROW. A spatial analysis of the location of these facilities and their associated impacts was beyond the scope of this study. However, based on pipeline documentation, the potential additional area associated with these facilities ranges from about 17 percent of total area impact for greenfield projects (e.g., Constitution [19]) to over 30 percent for looping projects (Leidy SE Franklin Loop [20], East Side Expansion [37]). Relative to the pipeline ROW area only (not the total impact area), these percentages are 20 percent for greenfield projects, and 45 percent for looping projects.

Wetland Area Impacts

For wetland impacts, developing reasonable adjustment factors is impractical because of the small areas involved for any individual pipeline. We report the results for our GIS analysis (Method A), which did take into account narrower ROWs when passing through wetland areas. In total, we estimate that within the DRB, the eight pipeline projects in this study will impact:

- 41 acres of wetlands within the construction ROW
- 22 acres of wetlands within the new permanent ROW.

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Discussion

This analysis computed the cumulative impacts of eight proposed natural gas transmission pipelines on existing land cover in the Delaware River Basin (DRB). The length of the new pipelines will total 322 miles within the DRB, a length roughly equivalent to the Delaware River itself. We found that the total area of new land disturbance is 2,977 acres (4.7 square miles) during construction and 1,328 acres (2.1 square miles) in the permanent right-of-way (ROW). These impacts only account for the ROWs directly, and not total impacts for associated activities such as road buildings, or equipment storage. Forests account for over one-third of the land area impacted (roughly 40 percent before adjustment). The basin-wide totals don't present the whole story, however. Our analysis showed that results vary significantly by pipeline, construction method, and watershed location.

We found that the cumulative area of impact was far greater than for any individual pipeline project, but several of the projects do have disproportionate impacts compared to the others. In part, this depends on the pipeline route and construction methods. Unsurprisingly, our results indicate that greenfield pipeline projects result in more land disturbance and forest loss per mile than looping projects or those that parallel an existing ROW. Combined, the PennEast, Constitution, and NJ Natural Gas Southern Reliability Link projects, which are all predominantly greenfield projects, account for well over half of the total potential disturbance area. The PennEast pipeline project has the largest potential impact within the DRB. The Mariner East 1 and 2, and Diamond East projects would affect a large amount of acreage due to their length, but less than they otherwise would, as the majority of their length is adjacent to existing pipeline ROWs. This reduction in affected acreage is more evident in the permanent ROW results than the construction ROW results, possibly because the wider working side of the pipeline usually can't be shared with existing ROWs, and requires new clearing.

The pipeline results also indicate a few key portions of the watershed with disproportionate impacts. The PennEast, Diamond East, and Leidy SE projects cross through the middle portion of the basin, especially the Lehigh, and Middle Delaware subbasins in Carbon, Northampton, Hunterdon, Luzerne, Monroe, Mercer, and Warren counties. These projects in particular pass through heavily forested areas, and account for the largest impacts on forests in the basin. The Mariner East, East Side Expansion, and Southern Reliability Link projects substantially affect the Brandywine-Christina, Lower Delaware, and Crosswicks-Neshaminy subbasins in the

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lower portion of the watershed, where the land cover tends to be more agricultural or developed. Finally, the Constitution Pipeline is the only pipeline of the eight affecting the Upper portion of the watershed as it passes through Broome County, NY. The land cover along its route is split between agriculture and forest. Of course, additional pipeline proposals could change the distribution of impacts in the future.

This analysis also demonstrated how geospatial analysis can be used to determine a rough estimate of land disturbance area based only on pipeline route information. There is often a considerable delay between the initial route proposal for a pipeline and the environmental analysis or environmental impact statement that includes a full accounting of the land cover impacts using detailed ROW information. The pipeline proponent and FERC will have access to the most authoritative information on the project, and are in the best position to assess potential impacts with a high degree of certainty. The higher-resolution data for both the pipeline ROW and potentially, existing land cover (plus, likely field surveying) allow a higher degree of certainty than we could achieve in this analysis. Nonetheless, our methodology in this report demonstrates that a fairly accurate initial estimate of impacts can be generated using only proposed and existing pipeline route information and the National Land Cover Dataset (NLCD). We validated our results, and found that the error in total disturbance area was less than 5 percent compared to the FERC environmental analysis documents. The specification of forest area impacted requires an adjustment factor to account for uncertainty and coarse resolution in the NLCD.

We also determined that small errors in the pipeline route are not likely to be extremely consequential with respect to land cover breakdown. Changes in overall length due to altered routes will of course affect acreage of impact, but small perturbations or uncertainty in the proposed route may not greatly affect results. The overall breakdown of land cover disturbance is nearly constant as theoretical ROW width expands, even far beyond the construction ROW. This leads to some potentially useful rules of thumb for pipeline construction. For instance, a 50-foot ROW will affect, on average, four acres of forest per mile in the DRB (based on the routes of these eight pipelines).

There are several ways this analysis could be expanded in the future. First, the analysis method could be applied to other geographic areas such as the Susquehanna River Basin or the entire State of Pennsylvania. At present, this analysis considers only land cover changes due to development of the pipeline ROWs, and potential stream crossings, but no secondary impacts on land or water resources. The results from this study could feed into secondary impact analyses. For instance, the permanent pipeline ROWs could be used with existing land cover data to estimate secondary forest impacts such as fragmentation and loss of core forest as a result of the new forest edges along the ROWs. Or the total disturbance area and existing land

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cover distribution could be used as inputs in a water quality model to estimate potential changes in sediment loading to streams.

It is worth noting that in Pennsylvania, pipelines are a special topic of concern because of the rapid increase in shale gas development since 2007. Some estimate that 30,000 miles of additional pipelines may be constructed in Pennsylvania in the next 30 years [41]. The majority of those will likely be the smaller gathering lines to move gas from production wells to the existing distribution network, but new transmission lines will also be needed to handle the increased production. In 2015, Pennsylvania Governor Tom Wolf appointed a pipeline task force, managed by the PA Department of Environment Protection, to study pipeline impacts in Pennsylvania and come up with a list of recommendations [42]. Similar to the motivations of this study, the task force found that the pipeline approval and permitting review process may not always account for long term, cumulative impacts: "Chosen routes do not necessarily avoid sensitive lands, habitats, and natural features. . . . Impacts to natural and cultural resources, landowners, and communities along them not always avoided, minimized or mitigated. . . . Individual decisions can accumulate into a much broader and longer impact on the citizens and the lands of a community, county or watershed" [42].

The Pipeline Task Force's report included 12 top recommendations, and 184 overall recommendations for improving the pipeline infrastructure development process in Pennsylvania [43]. These recommendations may affect the permit and approval process in the future, and thus, pipeline routing and construction methods. (Note that no policy changes have been adopted, and these state level recommendations likely will not directly affect the FERC process.) Accordingly, the methodology used in this study would have to be adapted to account for potential changes where possible. Some of the most relevant recommendations relate to better information sharing about pipeline routes, planning routes to avoid or mitigate environmental impacts, and construction methods and offsets to reduce net environmental impacts. The recommendation for earlier information sharing about proposed pipeline routes (including GIS data) would make assessing impacts with a methodology like the one used in this study easier. Other recommendations might affect ROW routes or widths. For instance, the recommendation to "Reduce Forest Fragmentation in Pipeline Development" could discourage routes from going through core forest areas. The recommendation to "Minimize Impacts to Riparian Areas at Stream Crossings" could result in changing assumptions about ROW width near stream crossings. Finally, several recommendations include policies for either mitigation banking or net loss limits for certain land cover types such as wetlands, forests in headwater watersheds, riparian buffers [43]. These types of policies would require more clarification in order to be modeled, and the methodology would have to account for the policies' impact through adjustment factors or additional assumptions (e.g., assume forest area loss is replaced within the same watershed).

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In summary, the next several years and decades will witness much more pipeline development in Pennsylvania and the Delaware River Basin. The pipeline projects will result in some impacts to land resources, water resources, cultural resources, ecosystems, and air quality, among others, even after accounting for project-specific mitigation measures. Analyzing several projects at once can give a clearer picture of potential cumulative impacts, but it requires timely and accurate geospatial information on proposed pipeline routes. It appears likely that Pennsylvania will consider recommendations to change the pipeline infrastructure development process to further mitigate or avoid impacts, especially for particularly sensitive resources. These changes may complicate future analyses such as this one, but may ultimately result in lessened impacts over the landscape of development.

Analyzing the cumulative impacts of concurrent pipeline projects is likely to be an ongoing need in Pennsylvania, for FERC interstate transmission pipeline proposals, and wherever pipeline infrastructure is being expanded. Pipelines are necessary to move liquid fuels across the country; they are an efficient means of transport, but their development does have short-term and long-term impacts on the landscape over which they are built. Policymakers at various levels may find analyses such as that presented in this study useful for comprehending how new pipeline proposals add to the cumulative impacts in geographic areas of interest. They may then determine whether mitigation measures may be appropriate, based on cumulative landscape impacts rather than solely on project-specific impacts.

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Appendix A: County and Watershed Results Tables

Table 11 displays the county-level area impact for the new permanent ROW, and Table 12 does so for the construction ROW.

Table 13 shows the impact area for the permanent ROW, broken down by land cover type and HUC10 watershed. Table 14 shows the impact area for the construction ROW, broken down by land cover type and HUC10 watershed.

Table 15 shows the number of stream crossings in each HUC10 watershed. These crossings reflect points of intersection between proposed pipeline routes and NHDPlus v2 stream flowlines within the DRB. We used existing pipeline routes to identify where existing crossings are located. In situations where a proposed pipeline's crossing is within 250 feet of an existing crossing, there may be the potential for a shared crossing, which could reduce the impact of the stream crossing. It is certainly possible these potential shared crossings may require a new crossing. Nonetheless, we have identified the total number of crossings, potential "shared" crossings, and the remaining crossings—which, by default, will be "new" crossings. Many of the new crossings that occur are associated with greenfield construction, and the potential shared crossing locations are typical for looping projects.

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Table 11. Total land disturbance by county for new permanent ROWs[a]

County	Forest	Wetland	Grassland/Shrub	Ag - Pasture	Ag- Cultivated	Open Land	Developed	Water	Total
Burlington, NJ	2.8	0.6	0.8	2.4	6.3	18.6	10.4	0.0	**41.9**
Gloucester, NJ	0.9	1.9	0.4	2.1	1.2	4.9	9.0	0.0	**20.6**
Hunterdon, NJ	76.0	1.2	10.8	39.2	40.5	7.5	0.7	0.0	**175.9**
Mercer, NJ	10.5	1.4	11.6	8.4	9.9	2.5	1.2	0.0	**45.5**
Monmouth, NJ	2.0	0.1	0.4	1.6	2.4	7.6	1.9	0.0	**15.9**
Ocean, NJ	2.4	0.8	0.5	0.4	2.6	21.9	23.6	0.0	**52.2**
Warren, NJ	9.3	0.4	0.5	1.1	14.0	3.8	0.5	0.1	**29.6**
Broome, NY	40.7	0.9	1.3	29.0	4.9	3.8	0.1	0.0	**80.8**
Berks, PA	43.9	0.3	8.4	14.6	14.3	18.1	11.3	0.1	**111.0**
Bucks, PA	0.6	0.0	1.5	0.9	6.5	0.4	0.3	0.0	**10.3**
Carbon, PA	137.7	1.7	2.0	13.0	1.2	9.8	3.6	0.4	**169.5**
Chester, PA	27.7	1.4	8.7	18.6	14.0	41.5	35.5	0.0	**147.5**
Delaware, PA	18.4	0.4	1.4	2.2	2.5	26.5	12.0	0.0	**63.4**
Luzerne, PA	65.8	4.9	9.7	0.0	0.0	2.2	0.5	0.0	**83.1**
Monroe, PA	63.5	5.3	0.2	4.2	1.4	14.1	0.6	0.8	**90.1**
Northampton, PA	53.4	0.5	5.8	15.3	82.6	22.1	10.5	0.0	**190.3**
TOTALS - by State									
Subtotal - NJ	*104*	*6*	*25*	*55*	*77*	*67*	*47*	*0*	***382***
Subtotal - NY	*41*	*0.9*	*1.3*	*29*	*5*	*4*	*0*	*0.0*	***81***
Subtotal - PA	*411*	*15*	*38*	*69*	*123*	*135*	*74*	*1*	***865***
TOTAL - DRB	**555**	**22**	**64**	**153**	**204**	**205**	**122**	**1**	**1328**

[a.] Land disturbance estimate computed by Method A (see table 5). Totals may not sum exactly due to rounding.

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Table 12. Total land disturbance by county for construction ROWs[a]

County	Forest	Wetland	Grassland/Shrub	Ag - Pasture	Ag- Cultivated	Open Land	Developed	Water	Total
Burlington, NJ	5.4	1.2	1.6	6.9	16.3	31.2	19.4	0.0	**81.9**
Gloucester, NJ	2.5	2.9	1.3	6.8	3.8	13.8	24.8	0.0	**55.9**
Hunterdon, NJ	157.9	2.2	24.1	88.9	92.0	15.3	1.6	0.0	**382.1**
Mercer, NJ	24.2	2.4	20.5	19.2	24.0	4.8	2.9	0.0	**97.9**
Monmouth, NJ	4.7	0.3	0.7	3.3	4.1	14.2	3.7	0.0	**30.9**
Ocean, NJ	6.1	1.2	1.2	1.2	9.4	37.8	44.9	0.0	**101.9**
Warren, NJ	29.1	1.0	1.7	2.9	41.6	10.8	1.8	0.3	**89.2**
Broome, NY	80.8	1.0	2.4	65.0	11.1	8.1	0.4	0.0	**168.8**
Berks, PA	115.6	0.9	22.6	35.3	38.1	45.2	26.8	0.1	**284.6**
Bucks, PA	1.2	0.0	3.2	2.2	15.4	0.7	0.4	0.0	**23.0**
Carbon, PA	276.5	2.5	4.0	31.6	2.9	20.3	7.5	0.5	**345.7**
Chester, PA	67.2	3.4	19.0	44.2	35.3	86.1	67.4	0.1	**322.6**
Delaware, PA	31.3	1.1	2.7	4.9	5.8	56.0	25.8	0.0	**127.7**
Luzerne, PA	150.4	9.8	14.3	0.0	0.0	5.1	1.1	0.0	**180.7**
Monroe, PA	170.9	9.1	0.5	13.3	4.0	40.6	1.9	2.1	**242.5**
Northampton, PA	121.5	1.9	12.7	35.3	197.4	49.9	22.1	0.2	**441.0**
TOTALS - by State									
Subtotal - NJ	*230*	*11*	*51*	*129*	*191*	*128*	*99*	*0*	***840***
Subtotal - NY	*81*	*1.0*	*2.4*	*65*	*11*	*8*	*0.4*	*0.0*	***169***
Subtotal - PA	*935*	*29*	*79*	*167*	*299*	*304*	*153*	*3.0*	***1968***
TOTAL - DRB	**1245**	**41**	**133**	**361**	**501**	**440**	**253**	**3**	**2977**

[a.] Land disturbance estimate computed by Method A (see table 5). Totals may not sum exactly due to rounding.

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Table 13. Pipeline land area impact [acres] by watershed, Permanent ROW

Watershed (HUC)	Forest	Wetland	Grassland/Shrub	Ag - Pasture	Ag- Cultivated	Open Land	Developed	Water	Grand Total
Upper Delaware	40.7	0.9	3.8	4.9	29.0	0.1	1.3	0.0	**80.7**
204010103	*40.7*	*0.9*	*3.8*	*4.9*	*29.0*	*0.1*	*1.3*		***80.7***
Middle Delaware	117.4	3.5	24.9	90.0	56.3	6.4	26.0	0.1	**324.6**
204010408	*4.2*		*0.4*	*0.5*	*1.3*	*0.4*		*0.0*	***6.8***
204010503	*5.1*	*0.4*	*7.6*	*11.5*	*0.4*	*2.6*	*0.1*		***27.7***
204010504	*6.0*	*0.3*	*1.2*	*3.2*	*0.5*	*0.2*	*0.3*		***11.7***
204010505	*3.8*	*0.3*	*0.8*	*3.4*	*1.5*	*0.3*	*0.2*		***10.3***
204010506	*15.9*	*0.2*	*5.6*	*21.6*	*7.2*	*1.2*	*3.3*	*0.1*	***55.0***
204010509	*82.4*	*2.4*	*9.3*	*49.9*	*45.4*	*1.9*	*22.0*		***213.2***
Lehigh	299.4	12.1	37.6	66.0	25.8	11.5	16.2	1.1	**469.7**
204010601	*30.9*	*2.8*	*5.0*	*0.7*	*0.5*			*0.5*	***40.5***
204010602	*82.9*	*7.0*	*2.4*			*0.5*	*9.7*	*0.1*	***102.7***
204010603	*63.9*	*1.8*	*7.3*	*0.2*	*2.4*	*0.3*			***75.9***
204010604	*50.6*		*7.1*	*0.0*	*3.8*	*0.3*	*0.6*	*0.3*	***62.7***
204010605	*34.0*	*0.4*	*3.9*	*1.1*	*9.2*	*3.3*	*1.6*	*0.2*	***53.9***
204010608	*36.9*	*0.1*	*11.9*	*63.9*	*9.8*	*7.1*	*4.2*		***134.1***
Crosswicks-Neshaminy	7.1	1.4	45.5	11.3	4.3	31.7	1.7	0.0	**103.0**
204020101	*4.6*	*0.9*	*33.3*	*6.9*	*3.6*	*26.0*	*0.9*		***76.1***
204020104	*2.4*	*0.5*	*12.2*	*4.4*	*0.8*	*5.7*	*0.8*		***26.9***
Lower Delaware	19.5	2.3	45.8	3.7	4.5	33.4	2.0	0.0	**111.2**
204020201	*0.1*		*2.6*			*4.3*	*0.0*		***7.0***
204020206	*19.4*	*2.3*	*43.2*	*3.7*	*4.5*	*29.1*	*1.9*		***104.2***
Schuylkill	44.9	0.5	13.7	19.4	17.2	20.4	9.1	0.1	**125.2**
204020303	*4.5*		*1.5*	*1.2*	*0.6*	*0.8*	*0.0*		***8.6***
204020304	*15.7*			*7.1*	*2.5*	*8.7*	*6.5*		***40.5***
204020306	*69.2*	*0.9*	*25.6*	*16.7*	*30.1*	*24.7*	*5.2*	*0.1*	***172.5***
204020307	*0.9*	*0.2*	*2.2*	*4.5*	*2.9*	*1.3*	*0.3*		***12.3***
204020310	*0.1*		*0.6*	*0.3*		*0.6*	*0.4*		***1.9***
Brandywine-Christina	26.5	1.2	26.9	9.3	15.6	25.6	7.9	0.0	**113.0**
204020501	*26.5*	*1.2*	*26.9*	*9.3*	*15.6*	*25.6*	*7.9*	*0.0*	***113.0***
TOTAL - DRB	**555**	**22**	**198**	**205**	**153**	**129**	**64**	**1**	**1327**

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Table 14. Pipeline land area impact [acres] by watershed, Construction ROW.

Watershed (HUC)	Forest	Wetland	Grassland/Shrub	Ag - Pasture	Ag- Cultivated	Open Land	Developed	Water	Grand Total
Upper Delaware	80.7	1.5	8.1	11.1	65.0	0.4	2.4	0.0	**169.2**
204010103	*80.7*	*1.5*	*8.1*	*11.1*	*65.0*	*0.4*	*2.4*		***169.2***
Middle Delaware	271.6	7.0	56.4	223.9	133.0	16.1	53.6	0.3	**761.8**
204010408	*13.3*		*1.1*	*1.5*	*5.3*	*0.9*	*0.0*	*0.0*	***22.0***
204010503	*18.8*	*1.3*	*17.2*	*29.5*	*1.5*	*6.5*	*0.4*		***75.3***
204010504	*18.7*	*0.6*	*2.9*	*9.7*	*1.3*	*0.7*	*1.0*	*0.0*	***34.8***
204010505	*11.5*	*0.8*	*2.3*	*9.7*	*4.6*	*0.9*	*0.7*		***30.4***
204010506	*37.3*	*0.2*	*14.1*	*58.8*	*18.4*	*2.6*	*8.2*	*0.3*	***139.8***
204010509	*172.0*	*4.1*	*18.8*	*114.7*	*101.9*	*4.5*	*43.4*		***459.5***
Lehigh	660.0	22.3	91.3	153.4	60.1	23.3	27.4	2.8	**1040.6**
204010601	*77.8*	*5.0*	*12.4*	*1.8*	*1.3*		*0.0*	*1.3*	***99.6***
204010602	*186.6*	*13.2*	*5.5*			*1.1*	*14.3*	*0.1*	***220.8***
204010603	*130.1*	*2.8*	*16.0*	*0.4*	*5.6*	*1.0*	*0.0*		***155.8***
204010604	*109.9*		*21.4*	*0.2*	*10.0*	*0.6*	*1.3*	*0.3*	***143.7***
204010605	*79.7*	*0.7*	*9.7*	*2.9*	*22.7*	*7.0*	*3.2*	*0.9*	***126.9***
204010608	*76.0*	*0.6*	*26.3*	*148.1*	*20.5*	*13.6*	*8.6*	*0.2*	***293.8***
Crosswicks-Neshaminy	15.7	2.7	79.6	29.8	11.4	58.4	3.1	0.0	**200.6**
204020101	*11.1*	*1.5*	*57.9*	*18.7*	*8.9*	*45.8*	*1.6*		***145.6***
204020104	*4.5*	*1.2*	*21.6*	*11.1*	*2.5*	*12.6*	*1.6*		***55.0***
Lower Delaware	34.9	4.2	93.1	9.7	11.8	73.7	4.8	0.0	**232.2**
204020201	*0.5*		*3.6*			*9.6*	*0.4*		***14.1***
204020206	*34.3*	*4.2*	*89.4*	*9.7*	*11.8*	*64.1*	*4.5*		***218.1***
Schuylkill	118.4	1.6	35.5	46.4	44.6	50.4	21.6	0.1	**318.6**
204020303	*13.3*		*3.2*	*3.6*	*1.4*	*1.6*	*0.0*		***23.2***
204020304	*33.1*		*0.0*	*15.9*	*5.6*	*19.2*	*15.1*		***88.9***
204020306	*69.2*	*0.9*	*25.6*	*16.7*	*30.1*	*24.7*	*5.2*	*0.1*	***172.5***
204020307	*2.4*	*0.7*	*4.6*	*9.7*	*7.4*	*3.0*	*0.4*		***28.2***
204020310	*0.4*		*2.1*	*0.6*		*1.9*	*1.0*		***5.9***
Brandywine-Christina	63.9	2.7	59.8	25.0	36.7	49.0	17.2	0.1	**254.4**
204020501	*63.9*	*2.7*	*59.8*	*25.0*	*36.7*	*49.0*	*17.2*	*0.1*	***254.4***
TOTAL - DRB	**1245**	**41**	**424**	**499**	**363**	**271**	**130**	**3**	**2977**

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Table 15. Stream crossings by HUC-10 watershed: total, shared (potentially, with existing crossings), and new (=total – shared)

Watershed (HUC10 #)	Total	Shared	New
Upper Delaware	11	0	11
204010103	*11*		*11*
Middle Delaware	39	15	24
204010408[a]			*0*
204010503	*6*	*6*	*0*
204010504	*3*	*3*	*0*
204010505	*3*	*3*	*0*
204010506	*6*	*3*	*3*
204010509	*21*	*0*	*21*
Lehigh	58	42	16
204010601	*13*	*13*	*0*
204010602	*20*	*19*	*1*
204010603	*4*	*4*	*0*
204010604	*9*	*4*	*5*
204010605	*4*	*2*	*2*
204010608	*8*		*8*
Crosswicks-Neshaminy	8	0	8
204020101	*5*		*5*
204020104	*3*		*3*
Lower Delaware	15	7	8
204020201	*0*		*0*
204020206	*15*	*7*	*8*
Schuylkill	18	8	10
204020303	*2*		*2*
204020304	*2*		*2*
204020306	*12*	*6*	*6*
204020307	*2*	*2*	*0*
204020310			*0*
Brandywine-Christina	26	20	6
204020501	*26*	*20*	*6*
TOTAL - DRB	**175**	**92**	**83**

[a.] HUC10 numerical codes shown grouped by HUC8 name. This HUC10 is in the Middle Delaware-Mongaup-Brodhead HUC8. The remaining HUC10s in this grouping are in the Middle Delaware-Musconetcong HUC8.

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Exhibit C

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SOUTHWEST PENNSYLVANIA ENVIRONMENTAL HEALTH PROJECT

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Summary on Compressor Stations and Health Impacts
February 24, 2015

Compressor station emissions

Compressor station emissions fall into two categories: construction emissions and operational emissions. Within operational emissions there are three types that warrant individual attention – blowdowns, fugitives and accidents. This document provides perspective on the aptness of the method of estimation (in tons per year) and need for further detail about the VOC and PM estimated emissions to better consider health risk.

Compressor construction and operational phases are generally projected to produce emissions below the NAAQS standards. They are presented in *tons per year*. This measure of emissions is used for NAAQS purposes which determines the air quality designation over a region and over long periods of time. The problem posed by estimating tons of contaminants emitted per year is that over the course of a year emissions will vary, often greatly. As phases of construction and operation change so will emissions content and concentrations. For a resident living near a compressor station, the concern is not simply PM2.5 emissions over the course of a year, but is PM2.5 emissions during the peak construction time when it's at its most intense.

Even during normal operations compressor stations have been shown not to emit uniformly ("blowdown" and accident events will be discussed separately).[1] The measurement *tons per year*, while common in the industry and common in the environmental field where regional air quality is at issue, is not an appropriate measure to determine individuals' health risks which increase during episodes of high exposures.

Table 4 shows the day to day and morning to evening variability in emissions at one compressor station near Hickory, Pennsylvania. It comes from a Pennsylvania Department of Environmental Protection. We present this case to show documentation of fluctuations not captured by averages.[2] Note how much relevant emissions information is lost when relying on averages, even of just three days. When extending this logic across a year, there is little doubt that there will be times of high levels of contaminants released and these high levels can increase health risks to residents. It is also notable that the EPA inhalation reference concentration (RfC) for ethylbenzene is 1 mg/m3 (equivalent to 1,000 ug/m3).[3] Some of the reported emissions exceed this standard of health safety.

2001 Waterdam Plaza Drive, #201, McMurray, PA 15317
Office: 724.260.5504 • Cell: 724.249.7501

Table 1. Variation in ambient air measurements of five VOCs near a compressor station reported in ug/m^3 *[4]

Chemical	May 18		May 19		May 20		3 day average
	morning	evening	morning	evening	morning	evening	
Ethyl-benzene	No detect	No detect	964	2,015	10,553	27,088	6,770
n-Butane	385	490	326	696	12,925	915	2,623
n-Hexane	No detect	536	832	11,502	33,607	No detect	7,746

*The PA DEP collected data on many more chemicals than those listed above; the authors of this paper have chosen these chemicals specifically to highlight variation in emissions.

Documented compressor emissions

It is important to know, with more specificity, what chemicals will be emitted by a compressor facility so that a targeted assessment can be made about its potential health impacts.

There is a small but growing body of literature on emissions from shale gas extraction, processing and transport activities. In its early stages of inquiry, the focus was predominantly on drill pad activity, but there are now some reports on natural gas compressor station emissions. Below are examples of chemicals that have been found at or near compressor stations during operations. These emissions reports – whether from public databases or from a private sector firm or organization – do not provide relevant background levels of the chemicals detected. Without a "control" location it is not possible to say with certainty that the chemicals found are the result of the compressor station, although these facilities are often the only industrial activity in the areas where they are found.

Emissions from two compressor stations (Stewart and Energy Corps), published by the Pennsylvania Department of Environmental Protection (DEP)[5] are:

MTBE
CO
iso-Butane
methyl mercaptan
n-Butane
n-hexane
n-octane
nitrogen dioxide
nitrous-acidstyrene
2-methyl butane
2 methyl pentane
3 methyl pentane
ethyl benzene
benzene
ethane
propane
methanol
napthlelene

The Texas Commission on Environmental Quality (TCEQ), as part of its Barnett Shale Formation Area Monitoring Projects found the following chemicals downwind from two monitored compressor stations[6]:

- Downwind of Devon Energy Company LP's Justin compressor station the TCEQ reports propane, isobutene, n-butane, ethane, cyclohexane, benzene, n-octane, toluene, m+p-xylene, n-hexane.
- Downwind of Targa North Texas LP's Bryan Compressor Station the TCEQ reports: ethane, propane, isobutene, n-butane, cyclohexane, n-octane, toluene, isopentane, n-pentane + isoprene, benzene.[7]

Officials in DISH, TX commissioned a study of compressor station emissions in its vicinity. Wolf Eagle Consultants performed whole air emissions sampling for VOCs, HAPs as well as Tentatively Identified Compounds (TICs). Chemicals identified as *exceeding* Texas's ESLs include: [8]

benzene
dimethyl disulfide
methyl ethyl disulphide
ethyl-methylethyl disulfide
trimethyl benzene
diethyl benzene
methyl-methylethyl benzene
tettramethyl benzene
naphthalene 1,2,4-trimethyl benzene
m&p xylenes
carbonyl sulfide
carbon disulfide
methyl pyridine
dimethyl pyridine

In 2011 and 2013, Earthworks, a non-profit organization, collected air samples within 0.33 miles of two compressor stations: Springhill compressor in Fayette County and the Cumberland/Henderson compressor station in Greene County, Pennsylvania.[9] Results from samples collected include:

1,1,2-Trichloro-1,2,2-trifluoroethane,
1,2-dichlorobenzene
2-butanone
benzene
carbon tetrachloride
chloromethane
dichlorodifluoromethane
ethylbenzene
methane
methylene chloride
tetrachloroethylene
toluene
trichloroethylene
trichlorofluoromethane

Anecdotally, we know that people living near compressor stations report episodic strong odors as well as visible plumes during venting or blowdowns. Residents often report symptoms that they associate with odors such as burning eyes and throat, skin irritation, and headaches. These are simply anecdotes but they are fairly consistently reported. It should be noted that residents in southwest Pennsylvania where these anecdotes were collected, often live near drill pads and in some instances processing plants along with compressor stations.[10]

Emissions pathways

In addition to the emissions produced during the normal operations of a compressor station there are several other ways that emissions might be dispersed from the site. These include fugitive releases, blowdowns, and accidents. Trucks play a significant role in the emissions profile during construction but are not common once the facility is complete and on line.

Fugitive emissions

Fugitive emissions are uncontrolled or under-controlled releases. They occur from equipment leaks and evaporative sources. It has been suggested that fugitive emissions will increase over time as machinery begins to wear.[11]

There does not appear to be a central publically available source of information of these emissions. There are, however, many opportunities for fugitive emissions to be released from a compressor station. We were able to locate only one study on natural gas compressor station fugitive emissions. In that study, conducted in the Fort Worth, TX area, researchers evaluated compressor station emissions from eight sites, focusing in part on fugitive emissions. A total of 2,126 fugitive emission points were identified in the four month field study of 8 compressor stations: 192 of the emission points were valves; 644 were connectors (including flanges, threaded unions, tees, plugs, caps and open-ended lines where the plug or cap was missing); and 1,290 were classified as Other Equipment. The Other category consists of all remaining components such as tank thief hatches, pneumatic valve controllers, instrumentation, regulators, gauges, and vents. 1,330 emission points were detected with an IR camera (i.e. high level emissions) and 796 emission points were detected by Method 21 screening (i.e. low level emissions). Pneumatic Valve Controllers were the most frequent emission sources encountered at well pads and compressor stations.[12]

Blowdowns

The largest single emission at a compressor station is the compressor blowdown.[13] They can be scheduled or accidental. As the natural gas rushes through the blowdown valve, a gas plume extends upward of 30 to 60 meters. The most forceful rush of air occurs at the very beginning, then the flow gradually slows down. The first 30 to 60 minutes of the blowdown are the most intense, but the entire blowdown may last up to three hours.[14] One blowdown vents 15 MCf gas to atmosphere on average. Isolation valves leak about 1.4 Mcf/hr on average through open blowdown vents.[15]

It is not possible to know what exactly would be emitted in a given natural gas compressor station blowdown as there is no data available. We know that it will include whatever is in the pipeline when the blowdown occurs. This would undoubtedly include the constituents of natural gas: methane, ethane, etc., and various additional constituents would be present during different episodes. We are especially concerned about the presence of radioactive material during a blowdown. Anecdotally, there are reports of odors and burning eyes, headaches and coughing associated with the events.[16]

An exposure to blowdown concentrations of contaminants would have different health implications than a long-term lower level exposure (i.e. yearly average) to the same contaminants when the compressor is on line.

Accidents

In addition to planned emissions, fugitive emissions and blowdowns there is also the possibility of accidents at the compressor station. There are no central national or state inventories of compressor station accidents that we were able to locate. In their absence we turned to local news accounts of individual accidents (which are generally in the form of fires). Without knowing what precisely is in the pipeline nor what else (if anything) may be housed on the site, it is not possible to estimate emissions from a fire at the compressor station. The possibility, however, is very real. A gas compressor station exploded near Godley, TX. That fire destroyed the compressor station where it started and also the one next to it. The fire burned for several hours.[17] In a compressor station fire in Madison County, TX volunteer firefighters from four towns were dispatched to the site. First responders blocked roads near the site and evacuated three homes.[18] In Corpus Christi, TX a fire broke out at a compressor station which then spread to nearby brush before being extinguished.[19]

The possibility of fire or other accidents raises the concern over whether the localities surrounding a compressor station have the resources available to contain a fire or explosion adequately and whether first responders and hospitals are able to care for injured workers or others nearby or whether an evacuation plan could be implemented. In Wheeler County, TX four contractors were performing maintenance activities near a compressor station when a flash fire occurred. The workers were brought to a nearby hospital. Two were treated and released; the other two were transferred to a burn unit in Lubbock.[20] In Carbon County, UT an explosion and fire damaged a natural gas compressor station and other buildings on the site injuring two workers and engulfing the facility in flame. Firefighters from every city in the county responded to the emergency. Injured workers had to be evacuated by medical helicopters.[21]

Overall, there is little information on the division of responsibility between the company operating the facility and the locality. This should be clarified.

The question of radioactivity

A 2008 publication of the International Association of Oil & Gas Producers has laid out the discussion on radioactive material in the natural gas extraction and production process.

> During the production process, naturally occurring radioactive material (NORM) flows with the oil, gas and water mixture and accumulates in scale, sludge and scrapings. It can also form a thin film on the interior surfaces of gas processing equipment and vessels. The level of NORM accumulation can vary substantially from one facility to another depending on geological formation, operational and other factors.
>
> [R]adionuclides such as Lead-210 and Polonium-210 can … be found in pipelines scrapings as well as sludge accumulating in tank bottoms, gas/oil separators, dehydration vessels, liquid natural gas (LNG) storage tanks and in waste pits as well as in crude oil pipeline scrapings.[22]

The gas which flows through the pipeline likely carries gaseous radon with it, and as radon decays within the pipeline, the solid daughter elements, polonium and lead, accumulate along the interior of the pipes. There is a concern that the gas transiting, and being compressed and regulated, will have radioactivity levels which will put at risk not only the workers at these stations and along the pipeline, but potentially also to the residents.[23] Radon, a gas, has a short half-life (3.8 days) but its progeny are lead and polonium, and these are toxic and have relatively long half-lives of 22.6 years and 138 days respectively.[24] There is no data that we can turn to in order to assess the risk of radioactive exposures in our community.

Health risks from relevant air contaminants

Averages, peaks and health events

As stated previously, one of our primary concerns is the poor fit of a *tons per year* measurement to the assessment of risk to the public's health near a compressor station. Furthermore, the National Ambient Air Quality Standards (NAAQS) used as a benchmark for air quality were not created to assess the air quality and safety in a small geographic area with fluctuating emissions. NAAQS effectively address regional air quality concerns. But these standards do not adequately assess risk to human health for residents living in close proximity to polluting sources such as unconventional natural gas development (UNGD) sites, where emissions can be highly variable.

Generally, it has been shown that:

1. Current protocols used for assessing compliance with ambient air standards do not adequately determine the intensity, frequency or durations of the actual

human exposures to the mixtures of toxic materials released regularly at UNGD sites, including compressor stations.

2. The typically used periodic 24-hour average measures can underestimate actual exposures by an order of magnitude.
3. Reference standards are set in a form that inaccurately determines health risk because they do not fully consider the potential synergistic combinations of toxic air emissions.[25]

Thus estimates of yearly totals of contaminants released by a compressor station do not allow for an assessment of the physiological impact of those emissions on individuals.

NAAQS reflects what, over a region, over time, is deemed safe population-wide. This is very different than what is safe within for instance 1200 feet of this compressor station. As already stated, averaging over a year can wash out important higher spikes in emissions (thus exposures) that may occur at various points throughout the year. These high spikes can put residents at risk for illnesses caused by air toxics.

Toxicity and characterization of exposures

Toxicity of a chemical to the human body is determined by the concentration of the agent at the receptor where it acts. This concentration is determined by the intensity and duration of the exposure. All other physiological sequelae follow from the interaction between agent and receptor. Once a receptor is activated, a health event might be produced immediately or in as little as one to two hours.[26] [27] In some instances, where there is a high concentration of an agent, a single significant exposure can cause injury or illness. This is the case in the instance of an air contaminant induced asthma event. On the other hand, after an initial exposure, future exposures might compound the impact of the first one, in time, producing a health effect. Repeated exposures will increase, for instance, the risk for ischemic heart disease.[28]

Peak exposures

Researchers have demonstrated the wisdom of looking at peak exposures as compared to averages over longer periods of time. Darrow et al (2011) write that sometimes peak exposures better capture relevant biological processes. This is the case for health effects that are triggered by, short-term, high doses. They write, "Temporal metrics that reflect peak pollution levels (e.g., 1-hour maximum) may be the most biologically relevant if the health effect is triggered by a high, short-term dose rather than a steady dose throughout the day. Peak concentrations … are frequently associated with episodic, local emission events, resulting in spatially heterogeneous concentrations…."[29]

Delfino et al (2002) posited that maxima of hourly data, not 24-hour averages, better captured the risks to asthmatic children, stating, "it is expected that biologic responses may intensify with high peak excursions that overwhelm lung defense mechanisms."

Additionally, they suggest that "[o]ne-hour peaks may be more influenced by local point sources near the monitoring station that are not representative of regional exposures…."[30]

Because episodic high exposures are not typically documented and analyzed by researchers and public agencies, natural gas compressor stations emissions are rarely correlated with health effects in nearby residents. However, examination of published air emission measurements shows the very real potential for harm from industry emissions.[31] Reports of acute onset of respiratory, neurologic, dermal, vascular, abdominal, and gastrointestinal sequelae near natural gas facilities contrast with research that suggests there is limited risk posed by unconventional natural gas development.

Health Effects from exposures to VOCs

VOCs, present at compressor station construction and operation, are a varied group of compounds which can range from having no known health effects to being highly toxic. Short-term exposure can cause eye and respiratory tract irritation, headaches, dizziness, visual disorders, fatigue, loss of coordination, allergic skin reaction, nausea, and memory impairment. Long-term effects include loss of coordination and damage to the liver, kidney, and central nervous system. Some VOCs, such as benzene, formaldehyde, and styrene, are known or suspected carcinogens.[32] The case for elevated risk of cancer from UNGD VOC exposure has been made by McKenzie et al (2012) and others.[33]

The inhalation of the VOC, benzene, produces a number of risks including

> [acute (short-term)] drowsiness, dizziness, headaches, as well as eye, skin, and respiratory tract irritation, and, at high levels, unconsciousness. Chronic (long-term) inhalation exposure has caused various disorders in the blood, including reduced numbers of red blood cells and aplastic anemia, in occupational settings. Reproductive effects have been reported for women exposed by inhalation to high levels, and adverse effects on the developing fetus have been observed in animal tests. Increased incidence of leukemia (cancer of the tissues that form white blood cells) have been observed in humans occupationally exposed to benzene. EPA has classified benzene as known human carcinogen for all routes of exposure.[34]

Benzene, which is documented at compressor stations by the States of Pennsylvania and Texas, carries its own risk, including risk for cancer.[35] [36] There is growing evidence that benzene is associated with childhood leukemia. Benzene affects the blood-forming system at low levels of occupational exposures, and there is no evidence of a threshold. It has been argued in the literature that "[t]here is probably no safe level of exposure to benzene, and all exposures constitute some risk in a linear, if not supralinear, and additive fashion.[37]

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Another substance that is detected near compressor stations is methylene chloride.

According to the EPA:

> The acute (short-term) effects of methylene chloride inhalation in humans consist mainly of nervous system effects including decreased visual, auditory, and motor functions, but these effects are reversible once exposure ceases. The effects of chronic (long-term) exposure to methylene chloride suggest that the central nervous system (CNS) is a potential target in humans and animals. Human data are inconclusive regarding methylene chloride and cancer. Animal studies have shown increases in liver and lung cancer and benign mammary gland tumors following the inhalation of methylene chloride.[38]

The VOC formaldehyde is also considered a Hazardous Air Pollutant (HAP) by the US EPA (EPA).[39] It is one of the emissions chemicals that the natural gas development industry is required to report, for instance to the PA DEP. According to these reports, compressor stations are the highest UNGD source for formaldehyde.[40] For the year 2012, emissions of formaldehyde from compressor stations in Pennsylvania ranged from 0.0 TPY to 22.5 TPY. [41]

A recent study of air emissions in the Barnett shale region of Texas found concentrations of formaldehyde at sites with large compressor stations.[42] Some of these concentrations were greater than the Texas Commission on Environmental Quality's health protective levels (page 62). Formaldehyde was one of 101 chemicals found in association with methane in this study. The research showed that aromatics in particular were associated with compressor stations.

Air exposures to formaldehyde target the lungs and mucous membranes and in the short-term can cause asthma-like symptoms, coughing, wheezing, and shortness of breath. The EPA classifies it as a probable human carcinogen.[43] The World Health Organization classifies it as carcinogenic to humans.[44] It has also been associated with childhood asthma.[45] The California Office of Environmental Health Hazard assessment (OEHHA) has "identified formaldehyde as a Toxic Air Contaminant and gives it an inhalation Reference Exposure Level (REL) of 55 ug/m^3 for acute exposures and 9 ug/m^3 for both 8-hour and chronic exposures.[46] The acute REL is 74 ppb based on irritation of asthmatics.[47] It has also been linked with adverse pregnancy outcomes and reproductive and developmental toxicity.[48]

More recent investigations on formaldehyde near compressor stations are focused on the chemical reaction between methane and sunlight.[49] While it is well known that stationary compressor station engines emit formaldehyde, it is less well known that formaldehyde may also be formed at these sites through this chemical reaction. While the research is ongoing, it suggests that health hazards associated with formaldehyde

may be greater than previously thought. Because reported health symptoms near compressor stations, such as respiratory impacts and shortness of breath, can be caused by exposure to formaldehyde, targeted monitoring of this chemical at these sites would be recommended.

Effects from exposure to particulate matter

In addition to the VOC exposure presented above, PM2.5 also poses a significant health concern and interacts with the airborne VOCs increasing their impact. In fact, at a compressor station PM2.5 may pose the greatest threat to the health of nearby residents. Fine particles are expected to reach a total of 1.136 tons for 2015 and 2016.

The size of particles determines the depth of inhalation into the lung; the smaller the particles are, the more readily they reach the deep lung. Particulate matter (PM10, PM2.5 and ultrafine PM), in conjunction with other emissions, are at the core of concern over potential effects of UNGD.

High particulate concentrations are of grave concern because they absorb airborne chemicals in their midst. The more water soluble the chemical, the more likely it is to be absorbed onto a particle. Larger sized particles are trapped in the nose and moist upper respiratory tract thereby blocking or minimizing their absorption into the blood stream. The smaller PM2.5 however, is more readily brought into the deep lung with airborne chemicals and from there into the blood stream. As the particulates reach the deep lung alveoli the chemicals on their surface are released at higher concentrations than they would in the absence of particles. The combination of particles and chemicals serves, in effect, to increase in the dose of the chemical. The consequences are much greater than additivity would indicate; and the physiological response is intensified. Once in the body, the actions between particles and chemicals are synergistic, enhancing or altering the effects of chemicals in sometimes known and often unknown ways.[50]

Reported clinical actions resulting from PM2.5 inhalation affect both the respiratory and cardiovascular systems. Inhalation of PM2.5 can cause decreased lung function, aggravate asthma symptoms, cause nonfatal heart attacks and high blood pressure.[51] Research reviewing health effects from highway traffic, which, like UNGD, has especially high particulates, concludes, "[s]hort-term exposure to fine particulate pollution exacerbates existing pulmonary and cardiovascular disease and long-term repeated exposures increases the risk of cardiovascular disease and death."[52] PM2.5, it has been suggested, "appears to be a risk factor for cardiovascular disease via mechanisms that likely include pulmonary and systemic inflammation, accelerated atherosclerosis and altered cardiac autonomic function. Uptake of particles or particle constituents in the blood can affect the autonomic control of the heart and circulatory system."[53]

Ultrafine particles (<0.1) get less attention in the literature than PM2.5 but is found to have high toxic potency.[54] These particles readily deposit in the airways and centriacinar region of the lung.[55] Research suggests increases in ultrafine particles pose additional risk to asthmatic patients.[56] Ultrafine particles are generally produced by combustion processes. They, along with the larger PM2.5, are found in diesel exhaust.

Diesel is prevalent during the construction phase of compressor station site. High levels of diesel exhaust from construction machinery as well as trucks increase the level of respirable particles. Health consequences of diesel exposure have been widely studied and include immediate and long term health effects. Diesel emissions can irritate the eyes, nose, throat and lungs, and can cause coughs, headaches, lightheadedness and nausea. Short-term exposure to diesel exhaust also causes inflammation in the lungs, which may aggravate chronic respiratory symptoms and increase the frequency or intensity of asthma attacks. Long-term exposure can cause increased risk of lung cancer.[57]

PM2.5 acute effects

There is an abundance of research on the health effects of short term PM2.5 exposure. Mills et al demonstrate that one to two hours of a diesel exhaust exposure, which occurs during the construction phase of development, includes reduced brachial artery diameter and exacerbation of exercise-induced ST-segment depression in people with pre-existing coronary artery disease; ischemic and thrombotic effects in men with coronary heart disease;[58] and is associated with acute endothelial response and vasoconstriction of a conductance artery.[59] Fan He et al. suggest that health effects can occur within 6 hours of elevated PM2.5 exposures, the strongest effects occurring between 3 and 6 hours. Such an acute effect of PM2.5 may contribute to acute increase in the risk of cardiac disease, or trigger the onset of acute cardiac events, such as arrhythmia and sudden cardiac death.[60]

Numerous epidemiological studies have demonstrated a consistent link between particulate matter and increased cardiopulmonary morbidity and mortality (Brook et al. 2004; Mann et al. 2002; Pope et al. 2002; Samet et al. 2009; Schwartz 1999).[61] Previous studies have suggested that PM2.5 exposure is significantly associated with increased heart rate and decreased heart rate variability (HRV; Gold et al., 2000; He et al. 2010; Liao et al. 1999; Luttmann-Gibson et al. 2006; Magari et al. 2001; Park et al. 2005).

In addition to short term exposures and associated effects, there is evidence of health impacts from long-term exposures.[62] An HIA reviewing data from a number of European cities found that nearly 17,000 premature deaths from all causes, including cardiopulmonary deaths and lung-cancer deaths, could be prevented annually if long-term exposure to PM2.5 levels were reduced. Equivalently, this reduction would increase life expectancy at age 30 by a range between one month and more than two years in the study cities. A Canadian national cohort study found positive and

statistically significant associations between non-accidental mortality and estimates of PM2.5, the strongest association being with ischemic heart disease. Associations in this study were with concentrations of PM2.5 as low as only a few micrograms per cubic meter.[63] Research has also shown that there is an association between PM2.5 and hospitalization for COPD in elderly people.[64]

There is also a considerable literature on the health effects specifically from diesel emission that include PM2.5 along with chemical components. Mills et al conclude that even dilute diesel emissions can induce risk and point to ischemic and thrombotic mechanisms for the adverse cardiovascular events associated with diesel exposure.[65]

After an extensive review the EPA concluded that

> long-term inhalation exposure is likely to pose a lung cancer risk to humans. Estimation of cancer potency from available epidemiology studies was not attempted…. A noncancer chronic human health hazard is inferred from rodent studies showing dose-dependent inflammation and histopathology in rats. Short-term exposures were noted to cause irritation and inflammatory symptoms of a transient nature these being highly variable across an exposed population. The assessment also indicates that there is emerging evidence fro the exacerbation of existing allergies and asthma symptoms.[66]

Children, pregnant women and air contaminants

Children and pregnant women are especially sensitive to pollution. Many studies confirm a range of adverse effects of air pollution on children's lung function and respiratory symptoms, especially for asthmatics. Recent studies have found statistically significant associations between the prevalence of childhood asthma or wheezing and living very close to high volume vehicle roadways.[67] Other research aimed specifically at children's PM2.5 exposure has found that PM2.5 and several of its components have important effects on hospital admissions for respiratory disease, especially pneumonia. The authors count among the sources for this exposure diesel exhaust, motor vehicle emissions, and fuel combustion processes.[68]

Health effects have been found in pregnant women from high particulate highway pollution. Such particle pollution "may provoke oxidative stress and inflammation, cause endocrine disruption, and impair oxygen transport across the placenta, all of which can potentially lead to or may be implicated in some low birth weight … and preterm births." The consequences do not stop with low birth weight and preterm births because these conditions can negatively affect health throughout childhood and into adulthood.[69]

Mixtures and sequential exposures

Mixtures of pollutants are a critically important topic in addressing the public health implications of UNGD broadly and compressor stations in this case. While this report has focused primarily on three pollutants (VOCs, formaldehyde as one example, and PM2.5), in fact, a very large number of chemicals are released together. Medical reference values are not able to take the complex nature of the shale environment, its multiple emissions and interactions into full consideration.[70] Although the shale gas industry is not unique in emitting multiple pollutants simultaneously, this industry is unique in doing so as close as 500 feet from residences.

Chemicals that reach the body interfere with metabolism and the uptake and release of other chemicals, be they vitally important biochemical produced and needed by the body or other environmental chemicals with potentially toxic effects. Some chemicals attack the same or similar target sites creating an additive effect. This is the case with chemicals of similar structure such as many in the class of VOCs. Some mixtures like PM and VOC act synergistically to increase the toxicity of the chemicals. Other chemicals released environmentally are rapidly absorbed and slowly excreted. These slowly excreted chemicals will interfere with subsequent actions of chemicals because the body has not yet cleared the effects from the earlier exposure.

Noise

Excessive noise has been associated with an array of psychological and physical effects. A review article on noise exposure and health risk published in *Noise and Health* claims that the evidence for a causal relationship between community or transportation noise and cardiovascular risk has risen in recent years. In sum, the author finds limited evidence for a causal relationship between noise and biochemical effects; limited or sufficient evidence for hypertension; and sufficient evidence for ischemic heart disease.[71]

According to a World Health Organization assessment of research, excessive noise can also increase risk of cognitive impairment in children, sleep disturbance, tinnitus, and high levels of annoyance.[72] Researchers have found associations between elevated sound levels – including community sounds levels – and hearing loss, reduced performance and aggressive behavior.[73] Additionally some attention is being paid to the health effects of vibration exposure which is connected with but distinct from noise itself.[74]

Noise exposures are associated with construction activities and during blowdown episodes. As with air exposures, the periods of extreme exposures (in this case noise exposures) can cause different and sometimes more serious effects than low-level exposures.

Summary

In sum, we know that a number of different chemicals as well as PM2.5 are present during the construction phase of compressor stations and they are present in close

proximity to compressor stations that are on line. Some, although not all, have documented health effects on vulnerable populations and on the population at large. What we do not know is the precise mix and concentration of chemicals that will be released into the air. Without that information it is not possible to assess the compressor station's full impact on area residents.

Reported health effects specific to compressor stations

There is a growing body of research on emissions and health impacts from UNGD generally, though few studies specifically address health impacts from compressor stations. This is partly due to the fact that many compressors are sited in proximity to other UNGD sites such as well pads, impoundments, condensate tanks and processing stations. As the infrastructure for transporting natural gas continues to expand, more pipelines, metering stations and compressor stations will be sited away from other UNGD facilities.

Recent research that has been conducted near compressor stations in different parts of the country shows consistencies in the types of symptoms experienced by those living near these sites. These symptoms are associated with health impacts on respiratory, neurological and cardiovascular body systems. It should be noted that in each of the studies cited here health survey forms were filled out by residents and, as such, the findings are self-reported. To date there have been no epidemiological studies performed to identify health impacts from compressor stations.

A peer-reviewed article, *Investigating Links Between Shale Gas Development And Health Impacts Through A Community Survey Project In Pennsylvania* (2014) is one of the few publications that explicitly addresses health impacts from compressors.[75] The report states:

> In the Pennsylvania study, distance to industrial sites correlated with the prevalence of health symptoms. For example, when a gas well, compressor station, and/or impoundment pit were 1500-4000 feet away, 27 percent of participants reported throat irritation; this increased to 63 percent at 501-1500 feet and to 74 percent at less than 500 feet. At the farther distance, 37 percent reported sinus problems; this increased to 53 percent at the middle distance and 70 percent at the shortest distance. Severe headaches were reported by 30 percent of respondents at the farther distance, but by about 60 percent at the middle and short distances. [76] P.62

Age groups also responded differently in terms of health symptoms:

> Among the youngest respondents (1.5-16 years of age), for example, those within 1500 feet experienced higher rates of throat irritation (57% vs. 69%) and severe headaches (52% vs. 69%). It is also notable that the youngest group had the highest occurrence of frequent nosebleeds (perhaps reflective of the more

> sensitive mucosal membranes in the young), as well as experiencing conditions not typically associated with children, such as severe headaches, joint and lumbar pain, and forgetfulness.
>
> Among 20- to 40-year-olds, those living within 1500 feet of a facility reported higher rates of nearly all symptoms; for example, 44 percent complained of frequent nosebleeds, compared to 29 percent of the entire age group. The same pattern existed among 41- to 55-year-olds with regard to several symptoms (e.g., throat and nasal irritation and increased fatigue), although with smaller differences and greater variability than in the other age groups.
>
> The subset of participants in the oldest group (56- to 79-year-olds) living within 1500 feet of facilities had much higher rates of several symptoms, including throat irritation (67% vs. 47 %), sinus problems (72% vs. 56%), eye burning (83% vs. 56%), shortness of breath (78% vs. 64%), and skin rashes (50% vs. 33%).
>
> In sum, while these data do not prove that living closer to oil and gas facilities causes health problems, they do suggest a strong association since symptoms are more prevalent in those living closer to facilities than those living further away. Symptoms such as headaches, nausea, and pounding of the heart are known to be the first indications of excessive exposure to air pollutants such as VOCs [36], while the higher level of nosebleeds in the youngest age group is also consistent with patterns identified in health survey projects in other states [9, 10].” P.64

Earthworks, a non-profit organization, conducted the Pennsylvania study referred to above, (Gas Patch Roulette 2012) in which they surveyed residents about health symptoms and conducted air and water tests near residences in Pennsylvania and New York[77]. In their report, specific mention is given of a residence 800 feet from a compressor station. Health symptoms experienced by the residents (parents and children) were extreme tiredness, severe headaches, runny noses, sore throats and muscle aches, as well as dizziness and vomiting by one individual.

Earthworks also conducted a health survey in Dish, Texas in 2009.[78] The health symptoms reported to be associated with compressors were: burning eyes, nausea, headaches, running nose, sore throat, asthma, sinus problems and bronchitis. Odors experienced by residents near compressor stations were described as: sulfur smell, odorized natural gas, burnt wire, strong chemical-like smell and ether.

Wilma Subra[79], an environmental chemist and consultant who is on the Earthworks Board of Directors, has compiled information on health symptoms experienced near compressor stations based on her research with communities concerned about health impacts from UNGD[80]. Subra has served as Vice-Chair of the Environmental Protection Agency National Advisory Council for Environmental Policy and Technology (NACEPT),

and recently completed a five year term on the National Advisory Committee of the U.S. Representative to the Commission for Environmental Cooperation and a six year term on the EPA National Environmental Justice Advisory Council (NEJAC) where she served as a member of the Cumulative Risk and Impacts Working Group of the NEJAC Council. While her research on health impacts associated with compressor stations is reported back to communities, most of the data shown here have not been published in peer-reviewed journals (she is an author on the above-mentioned peer-reviewed article on Pennsylvania data).

Subra has reported the following health impacts in association with compressor stations:

Table 2. Most Prevalent Medical Conditions In Individuals Living in Close Proximity to Compressor Stations and Metering Stations

Medical Conditions:	% of Individuals (71)
Respiratory Impacts	58
Throat Irritation	55
Weakness and Fatigue	55
Nasal Irritation	55
Muscle Aches & Pains	52
Vision Impairment	48
Sleep Disturbances	45
Sinus Problems	42
Allergies	42
Eye Irritation	42
Joint Pain	39
Breathing Difficulties	39
Severe Headaches	39
Swollen & Painful Joints	32
Frequent irritation	32

The full list of health impacts "Reported by Community Members Living 50 feet to 2 miles from Compressor Stations and Gas Metering Stations Along Gas Transmission Pipelines" is available at the Luzerne County Citizens for Clean Air website[81]. It is notable that Subra reports that 61% of health impacts are associated with the chemicals present in the air that were in excess of short and long term effects screening levels.

Subra further reports that the following units at compressor stations and gas metering stations release emissions into the air:

Compressor Engines

Compressor Blowdowns

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Condensate Tanks
Storage Tanks
Truck Loading Racks
Glycol Dehydration Units
Amine Units
Separators
Fugitive Emission Sources

She reports that 90% of individuals surveyed reported experiencing odor events from these facilities. Based on her analysis, the following health symptoms are associated with the chemicals detected in the air at compressor stations:

Allergies
Persistent Cough
Shortness of Breath
Frequent Nose Bleeds
Sleep Disturbances
Joint Pain
Difficulty in Concentrating
Nervous System Impacts
Forgetfulness
Sores and Ulcers in Mouth
Thyroid Problems

Subra reports that both the construction and production phases of compressor stations can cause acute and chronic impacts. In the construction phase impacts come from diesel truck emissions and from dust particles. In the production phase impacts are derived from constant emissions, venting, blowdowns, accidents/malfunctions and from the effects of noise, light and stress. She considers respiratory health impacts of particular concern, and vulnerable groups such as pregnant women, children, the elderly and sensitive individuals to be at greatest risk. Acute and chronic health impacts that Subra has documented are listed below.

Acute Health Impacts Experienced by Individuals Living and Working near Compressor Stations

Tense and nervous
Joint and muscle aches and pains
Vision Impairment
Personality changes
Depression, Anxiety
Irritability
Confusion
Drowsiness
Weakness
Irregular Heartbeat
Irritates skin, eyes, nose, throat and lungs
Respiratory impacts
Sinus problems
Allergic reactions
Headaches
Dizziness, Light headedness
Nausea, Vomiting
Skin rashes
Fatigue
Weakness

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Chronic Health Impacts Experienced by Individuals Living and Working near Compressor Stations

- Damage to Liver and Kidneys
- Damage to Lungs
- Damage to Cardiovascular System
- Damage to Developing Fetus
- Reproductive Damage
- Mutagenic Impacts
- Developmental Malformations
- Damage to Nervous System
- Brain Impacts
- Leukemia
- Aplastic Anemia
- Changes in Blood Cells
- Impacts to Blood Clotting Ability

Radioactive elements: a long-term health threat

The possibility of exposure to radiation from natural gas pipelines and compressor stations is also a concern, especially for long-term health effects. The New York public health group, Concerned Health Professionals of New York, describes the problem in their report, Compendium Of Scientific, Medical, And Media Findings Demonstrating Risks And Harms Of Fracking (Unconventional Gas And Oil Extraction) (July 10, 2014): "Unsafe levels of radon and its decay products in natural gas produced from the Marcellus Shale, known to have particularly high radon content, may also contaminate pipelines and compressor stations, as well as pose risks to end-users when allowed to travel into homes."(P.5). Health impacts from exposure to radioactive materials in compressor station emissions have not been documented, but the risk of exposure to these carcinogens are a serious public health concern.

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