Environment, Energy, and Economy: Impacts of Natural Gas Pipelines in 9 Watersheds of North-central Pennsylvania

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I. Abstract

While exploitation of the Marcellus Shale constitutes a major economic opportunity for leaseholders and the state of Pennsylvania, it also has brought persistent concerns over the environmental and economic impacts this may have on air and water quality, forest health, property values, and wildlife. This project examined 3 specific aspects of natural gas related activity in 9 watersheds of various drilling intensities in north-central Pennsylvania. The impacts of gathering pipeline in particular were examined, including their role in forest fragmentation, the energy return on investment (EROI) associated with their construction, and how this energy return was distributed over the well's lifetime to date. The results revealed that gathering pipelines likely caused minimal losses in forest cover from 2005 to 2010 in 4 of the 6 sites featuring drilling activity. Losses could be attributed to pipelines even in high intensity sites that initially had less forest cover than the low intensity sites. The EROI of pipelines included both their embodied energy and their construction costs, and was found to constitute less than 3% of the energy return, given three different scenarios of EROI analysis in which wells of a low (1.3 trillion Btu) or high (2.6 trillion Btu) lifetime productivity were compared to energy costs of pipeline lengths with three different diameters (12, 20, and 24 inches). Finally, reporting data obtained from the state Department of Environmental Protection was analyzed to produce decline curves for 54 wells in Susquehanna and Bradford counties. Fifty of the wells reached their maximum production within a year of being drilled, and by the wells' second reporting periods (an average of 546.98 days after completion), 31 of the 46 applicable wells were producing less than half of their maximum. The study revealed that drilling activity in the area is proceeding according to the high development scenario projected by The Nature Conservancy, but that space between pads and total pipeline lengths is smaller than initially predicted.

The results suggest that increasing the number of wells on a well pad is key to a number of improvements. Forest fragmentation as well as impacts on biological communities would be minimized with fewer disturbances and less pipeline. This would require drillers to consolidate leases, but would also result in a smaller investment of energy in pipelines. Municipalities should be aware that gathering lines may open up "highways" of drilling activity and should be allowed to maintain their zoning rights. Finally, multiple wells per pad would ameliorate the replication of impacts sacrificed for what could be a lifetime far less than the 40-50 years suggested by drilling advocates.

II. Introduction

The natural gas industry is experiencing rapid growth in north-central Pennsylvania as it expands production in the Marcellus Shale, an organically-rich geological formation that is estimated by the United States Geological Survey (USGS) to contain up to 84 trillion cubic feet of undiscovered, technically recoverable reserves (USGS, 9/23/11). The Nature Conservancy (TNC) estimates that up to 60,000 wells could be drilled in the state by 2030. Depending on the number of pads to accommodate these wells, there could be between 6,000 and 15,000 well pads cleared and constructed (Johnson, 2010). In light of such growth, there is much debate over the economic and ecological impacts of the drilling process and its supporting infrastructure, including concerns over water use, water contamination, roads, forest fragmentation, air pollution, and land subsidence. How to exploit the Marcellus Shale safely—indeed, whether it should be exploited at all—is a topic of contention that has pitted government officials, industries, and NGOs against one another, not least of all neighbors within small rural towns that face the direct consequences of denying or granting the permission of drillers in their midst (Phillips, 3/28/12).

While all of the above concerns are warranted and subject to study, this project focused on the relative impact of natural gas pipelines, including their embodied energy, their impacts on forest cover, and how their construction and placement may be related to a well's productive lifetime. The need to study pipelines has become more apparent with each approved well and pipe upgrade, as they are representative of high investments in the natural gas sector, the potential economic boosts their construction entails, and the controversy surrounding their routes through both public and private land. About 3 billion cubic feet per day (bcfd) flows from the Marcellus region, and as of August 2011, a dozen projects are underway to transport an additional 4 bcfd by pipe to markets as far away as New York and Boston. The Marc 1 Hub Line, for example, has been proposed in the Endless Mountains region of Pennsylvania, but the project has experienced turbulence in the form of concerned citizens wanting to protect their forests, waterways, and farms, and even from the EPA, which believes construction of the line would endanger the surrounding environment (Levy, 9/14/11). Yet this may only be the beginning of the tension; one study states that 10,000 to 25,000 miles of new natural gas pipelines may soon lie under the state (Tanfani and McCoy, 12/10/11).. The amount of pipeline laid will also be dependent on how many wells per pad, but the addition of these pipes raises concerns over habitat fragmentation, impacts on wetlands, emissions from machinery (e.g. compressors) alongside the pipes, maintenance and inspection for leaks, etc. (Levy, 9/14/11).

The region of north-central and north-eastern PA is feeling these development pressures acutely. To name just a few of the newest projects: the 120-mile Constitution Pipeline has been approved for construction and will transport 500 MMcfd from Cabot Oil and Gas wells in Susquehanna County along Williams Partners' gathering lines to the Iroquois Gas Transmission Line and the Tennessee Gas Pipeline. Williams Partners' capacity reached 750 MMcfd as of May 2011 with the commissioning of its new Springville line from Susquehanna County to the Transco interstate pipeline. (Smith, 2/21/12). Chief Gathering LLC also has begun work on a $150 million gathering line in Wyoming County (McCoy and Tanfani, 12/13/11). Laser Northeast Gathering Company, LLC, on the other hand, has seen some of its new assets swing into action in the fourth quarter of 2011, which consists of a number of new compressor stations and pipelines. Its "Susquehanna gathering system" transports gas through Wyoming and Susquehanna counties to both the Millennium interstate pipeline as well as the Tennessee Gas Pipeline (Northeast Gathering Company LLC). In 2010, the Tennessee Gas Pipeline Company's 300 line began a $700 million expansion of their interstate line, and are building 127 miles along their existing line just south of the study area (described below) and northern New Jersey (Levy, 9/14/11). These rapid expansions of construction are complemented by a confusing swirl of business transactions and takeovers in an attempt to capitalize on the huge profits flowing from the Marcellus wells. The decisive winner at this point in time is Williams Partners. In December 2011, Williams Partners bought the Laser Northeast Gathering System for $329 million and is poised to complete the Susquehanna Supply Hub, which is expected to supply 4 interstate pipelines with at least 3 bcfd of Marcellus gas by 2015 (Smith, 2/21/12).

What's more, gathering pipelines in Pennsylvania are subject to scant oversight by regulatory bodies. In fact, Alaska and Pennsylvania are the only 2 of the 31 natural gas producing states that do not have a state body dedicated to monitoring intrastate pipes (Phillips, 8/5/11). Unlike interstate pipelines which are regulated by the Federal Energy Regulatory Commission (FERC), intrastate pipes in rural areas fall into something of a no-man's land in terms of their monitoring and their inspection. Surprisingly, the state of Pennsylvania does not know where all of its pipelines are located. The state's governor, Tom Corbett, signed legislation in December that would require the Public Utility Commission (PUC) to take on this duty, but it is a slow process that an already overburdened regulatory body. However, in yet another gap, the PUC is charged with enforcing federal rules, but those federal rules, on procedures such as welding and pipe weight, do not apply to pipelines in rural areas such as those where many Marcellus wells are being drilled (McCoy and Tanfani, 2/12/11). The “Class 1” loophole, as it is called, refers to gathering lines that have 10 or less homes for every mile of pipe within a quarter-mile of the right-of-way. The Pipeline and Hazardous Materials Safety Administration (PHMSA) does not enforce state or federal regulations in Class 1 areas, although pipeline construction companies claim they are working to higher standards (McCoy and Tanfani, 2/11/11). For the miles upon miles of new gathering lines currently being built, permits are only required if they cross a wetland or a waterbody, or run through a tract of land that is home to an endangered species. These permits are granted by the Pennsylvania Department of Environmental Protection, with an additional county-level regulation perhaps coming into play (Phillips, 8/5/11).

The growth of pipelines will indeed be an enduring aspect of development of the Marcellus Shale, although there is much work to be undertaken before one can ascertain what their true impact may be. The project presented in this report offers an integrated approach to understanding the role of pipelines and quantifying their impacts and their values at a watershed value. As opposed to broad generalizations of phenomena in the Marcellus Shale, this study seeks to illuminate the changes over time in a geographically small area where drilling has taken place at different levels of intensity. In examining the ecology, energy, and economics of pipeline infrastructure and how it compares to well productivity, one can hope to establish the strengths and weaknesses of the current practices dominating pipeline procedures, and the best ways to address the shortcomings can be subsequently determined. Ultimately, the study hopes to shed light on the best land use options available for natural gas drilling with respect to pipeline placement, and to offer insight into how the lifetime of pipeline infrastructure correlates with the lifetime of wells. With heavy investment and high hopes in the Marcellus play, skeptics cannot help but think that the energy sector is betting higher and higher with each new high-pressure pipeline installed, and this study aims to clarify the basis for these hopes, and what inevitable trade-offs our society will face as the Marcellus boom stretches before us.

III. **Background**

a. Environment

The environmental impacts of the thousands of miles of new gathering lines that will be constructed in Pennsylvania have been largely uninvestigated. To focus exclusively on gathering lines becomes almost a question of semantics in the case of the Marcellus Shale: the working definition of a "gathering line" is the steel pipeline that transports gas directly from a well pad to larger pipes known as "transmission lines." But the implications of this definition quickly become murky when viewing the tangled landscape of pipes in Pennsylvania's Gasland, and in 2006 PHMSA left the delineating to the American Petroleum Institute (API). The API's guide did not solve matters, as its methodology would leave the same pipe classified several ways, leading to suspicions that that the industry is simply protecting its profits. Pipeline companies paid $70 million in 2011 to the government in user fees; this fee, along with additional compliance costs, is dependent upon the classification of the pipelines under their jurisdiction. Therefore, these companies have a vested interest in seeing their pipelines classified as gathering lines—even if it runs 76 miles from the well field (McCoy and Tanfani, 12/11/11).

Aside from this complication, the potential impacts of wellpads and pipelines in forested areas have already been the focus of much scrutiny by The Nature Conservancy (TNC). In a 2010 report, TNC estimated that under a medium development scenario, about 6,350 wells would be drilled in the forests of PA, of which 56,000 acres would have to be cleared with an accompanying 135,000 acres of forest impacted by defragmentation (Johnson, 5/20/11). In a follow-up report, TNC tackled the issue of gathering lines. It determined that the majority of pipelines that will be built in the Marcellus region in the next 20 years will be gathering lines, and that the amount would be anywhere from 4 to 12 times the lengths of gathering line presently buried. It noted that traditional gathering lines have a diameter of 2 to 6 inches, but due to the explosion in production in the Marcellus region, gathering lines are now anywhere from 6 to 24 inches in diameter. With a larger diameter comes a larger right-of-way (ROW) width, and TNC estimated that Marcellus gathering lines will occupy a ROW anywhere from 30-150 feet (with 50 feet being the typical width kept free of vegetation). In Bradford County, specifically, where TNC performed its analysis, the ROW was more likely to be 100 feet, which they found disturbs 12 acres of forest and creates 72 acres of forest edges.

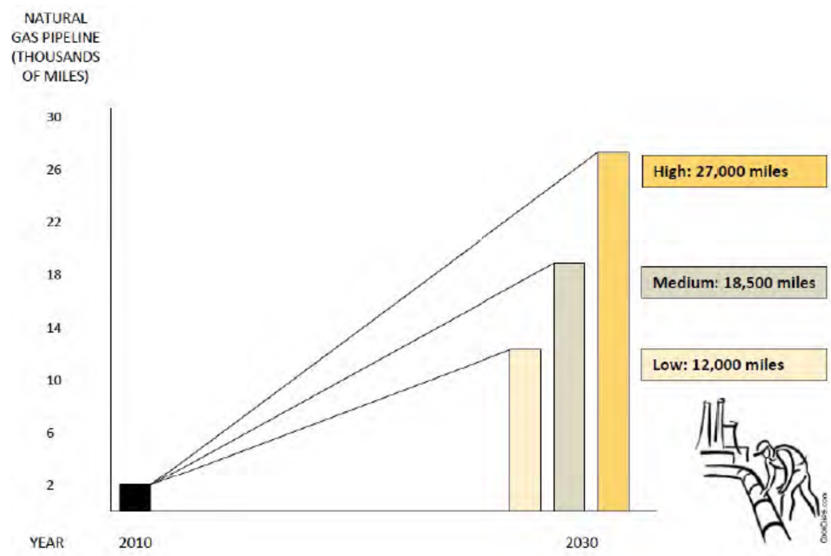


Figure 1: Miles of gathering line projected to 2030 dependent on development scenario: low (6,000), medium (10,000), and high (15,000) (Johnson et al., 1/9/12)

Extrapolating from data from Bradford County, approximately 16,500 miles of new gathering pipeline will be built, assuming a medium development scenario in which 10,000 pads are cleared and 1.65 miles of gathering line is used per pad. Applied at the statewide level, this implies 120,000 to 300,000 acres will be affected directly and indirectly by pipeline construction, and about half of this acreage will lie in forests (Johnson et al., 1/9/12). *(See Figure 1).* TNC additionally projected that approximately 3,500 well pads could be constructed within half a mile of state-designated High Quality or Exceptional Value streams, and that 113 of the 138 intact native brook trout watersheds will face possible impacts of Marcellus Shale development (Johnson, 5/20/11). The mitigation of pipeline impacts has been answered in part by the report issued by the Pennsylvania Marcellus Shale Commission in 2011, which included the expansion of current pipeline capacity and the sharing of ROW corridors to minimize surface impacts, maintain consistency in the siting regulations of new pipeline routes at the local, county, and state level, and take steps to better protect sensitive habitats (Governor’s Marcellus Shale Advisory Commission, 3/12/12).

While effects on biotic communities are sure to surface from the laying down of thousands upon thousands of new pipeline, other ecological impacts associated with natural gas drilling have also been investigated. One preliminary study of the effect of different drilling densities on small watersheds in the North Branch of the Susquehanna River was conducted by Frank Anderson in July 2010, which forms the basis for the study area of this project. His project design focused on three watersheds for each level of drilling intensity: none (reference watersheds), low (0.39-0.61 wells/km^2), and high (0.75-2.38 km^2). Watershed forest cover ranged from 34% in a high density site to 63% in a reference site. His results indicated a positive correlation with higher well density and higher levels of specific conductance and total dissolved solids, as well as a negative correlation with higher well density and lower levels of macroinvertebrate community richness. His study hints at the possibility of a drilling threshold, above which ecological impacts are quantifiable (ANSP, 5/2/11). In making his study area the subject of this project, I hope to discern if there may also be a threshold for pipeline impacts, or if my findings bolster or criticize an element of Anderson's preliminary study.

b. Energy

Just as understanding the environmental impacts of pipeline is crucial to the future of Marcellus exploitation, so is garnering an estimate of the energy expenditure on these pipelines as compared to the energy return from the natural gas wells which they serve. The calculating of an energy return on investment (EROI) is an acceptable strategy with several advantages, including: comparisons among different energy sources, insight into energy quality and net energy gain with large production chains, and how the energy quality of particular fuel or resource changes over time. An EROI may be defined as:

$$EROI = \frac{E_g}{E_c + E_{op} + E_d}$$

where E_g is the gross energy produced, E_c is energy for construction, E_{op} is the energy used for operation and maintenance, and E_d is the small amount of energy required for decommissioning. (Murphy et al., 2011). Creating an EROI for the embodied energy of the steel pipeline as well as the construction process adds insight into the net energy gained from Marcellus Shale exploitation, and may help balance the economical equation surrounding the question of fast-paced development in the play, especially in the case of environmental impacts.

An EROI has been calculated for natural gas by several different authors, and the ones of special prominence in regards to this study include analyses of conventional gas drilling by Charles Hall, and hydraulic fracturing by Michael Aucott in 2011. Hall estimated that as of 2005, natural gas production in the United States had an EROI of approximately 20:1 (Hall, 2008). *(See Figure 2 below)*. This value follows historic peaks of 36:1 in 1968 and 38:1 in 1973 in an overall trend of declining value (Hall et al., 1986). At this return, natural gas exploitation remains well below the return of approximately 80:1 for coal, and is far more competitive with both domestic and imported oil (Hall, 6/4/11).

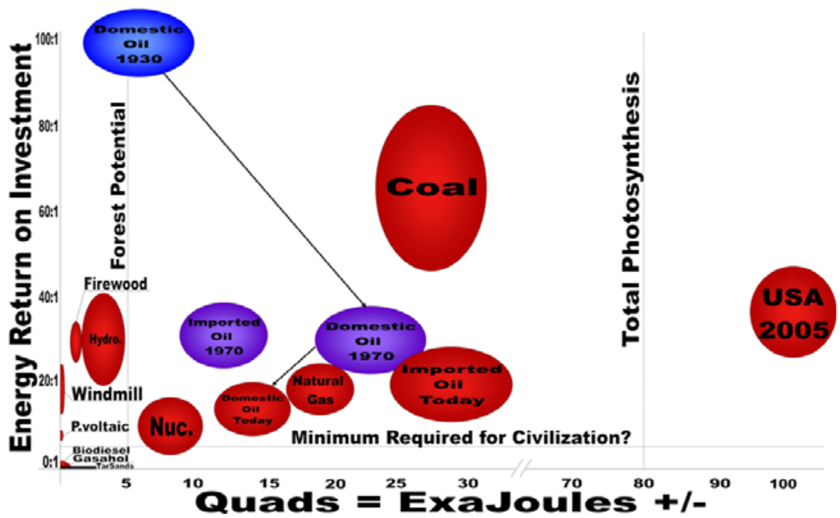


Figure 2: EROI of various domestic energy sources (Hall, 6/4/11).

Similarly, a 2008 study by Button and Sell on 100 conventional dry gas wells in Indiana County, Pennsylvania determined system boundaries of both direct energy expenditures (i.e. diesel fuel) and indirect (i.e. the energy used to create the steel, cement, sand, and water used in drilling) to conclude that natural gas had an EROI of approximately 10:1 in 2005 (Button and Sell, 9/25/11). This is to be expected following the rationale that the reserves easiest to reach require the least amount of energy, and that as the reserves become increasingly scarce or harder to acquire, the amount of energy consumed to extract a unit of energy will be greater (Hall et al, 1986). While new technologies are thought to give the extraction process a boost, Hall et al. claim that the "development of increasingly sophisticated technologies rarely offsets the increasing energy requirements for finding and extracting lower-quality fuel resources (29)." This historic precedent sets virtually all fossil fuels on such a trajectory of decline.

However, the onset of drilling in the Marcellus Shale, a so-called "unconventional" gas field, has seen technological updates coupled with what is viewed as a very productive play. Horizontal drilling and the use of hydraulic fracturing (also called "hydrofracking" or simply "fracking") has enabled industries to unlock large amounts of methane from the shale within a few days of drilling. Initial production rates can be as high as 1 million cubic feet (mmcf) per day (USGS).

Accordingly, the EROI of natural gas production is affected. While no official study has been published on the EROI of hydraulic fracturing in shale gas, Michael Aucott has put forth a preliminary study stating that it is 70:1 (9/23/11), which compares quite favorably to that of coal, which is 80:1 (Hall, 2008). There are several implications for this finding, including that natural gas in the Marcellus Shale is a precious energy source that will figure prominently into the future of this nation. On the other hand, if the return is indeed 70:1, economic and environmental concerns may be overshadowed by the more practical concerns governing our ability to transition to renewable energies while finding a cleaner substitute for coal and oil, which natural gas easily represents. However, Aucott's preliminary study offers several opportunities for improvement. This includes the energy expended in pipelines, as he did not account for construction costs and assumed 10 miles of 20 inch pipeline would service 10 wells. This project will refine his work by taking into account the construction costs of the pipelines, and also better illuminate the relationship between number of wells per well pad and pipelines that serve them, for which Aucott admitted there being "considerable uncertainty" (9/23/11).

The construction process for natural gas pipelines is discussed at length in *Natural Gas Pipeline Technology Overview* by Argonne National Laboratory. It describes the general procedures surrounding the creation of the pipe, the excavation of the trench and its depth requirements, the pipe stringing, bending, and welding, and finally, the hydrostatic testing that also occurs to ensure all pipes meet federal regulations (where they apply) and are functioning properly. It also has information on accompanying pipeline equipment, such as the compressor stations which are located every 40 to 100 miles along the pipeline route, and are situated on 15 to 22 acres of land. These facilities cleanse the gas (i.e. dehydrate it) and re-pressurize it with turbines that typically consume a percentage of the gas flowing through it. Other infrastructure includes valves located every 5 to 20 miles along the pipe, as well as metering stations and "pigging" facilities that are used to measure the flow of the gas and launch "pigs," devices that can clean the inside of the pipe (Folga, 10/1/11). Pipelines are no simple undertaking, and those in the Marcellus region are not only larger and more highly pressurized than their historic counterparts, but they are also being built at a higher rate than before (Johnson et al., 1/9/12).

c. <u>Economy</u>

While possible environmental consequences of natural gas drilling have been explored, the other side of the debate focuses on the economic longevity of developing the Marcellus Shale and its associated infrastructure, such as pipelines. Questions arise as to the true productivity of the wells, and their lifetime production curve. The industry claims that the life of a Marcellus well stretches as far into the future as 40-65 years from initial production. Other dissenting voices, such as that of petroleum geologist Arthur Berman, claim a well lifetime, and its total production, are much lower. Through his own analysis, he discovered that wells drilled over the past six or seven years in the Barnett Shale are now not producing enough gas to pay for the cost of compressing it along the transmission lines. Moreover, the decline curve associated with projected production rates of horizontal wells often uses a b-factor, which describes curvature, of greater than 0.5, which is recommended by the Society for Petroleum Engineers. Using a b-factor above 0.5 flattens the hyperbolic curve to draw out well life at a higher production rate and makes them appear more commercially valuable. However, as Berman found in his analysis, the majority of the net present value of the wells drilled by Chesapeake Energy in the Barnett Shale is during the first 5 years, and drops significantly after the first two decades (Berman, 9/20/11).

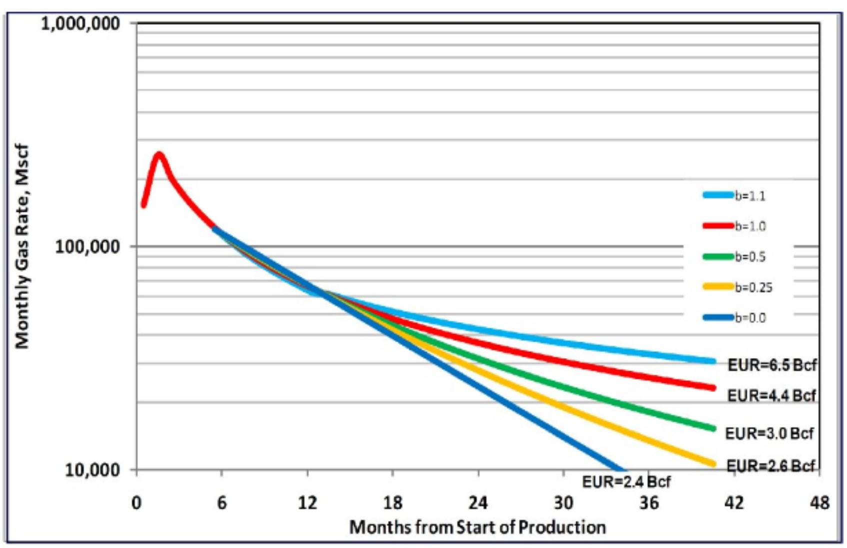


Figure 3: Normalized Haynesville Shale production decline rate using various b-factors. The differences in the lifetime of a well and its ultimate production changes dramatically depending upon the b-factor used. A b-factor of 0.5, recommended by the Society for Petroleum Engineers, would put lifetime production for a well at approximately 3.0 Bcf a month (Berman, 9/20/11).

Berman concludes the preceding analysis by arguing that the Marcellus Shale constitutes the latest stage in development of an industry that must heedlessly move to the next play with the next round of profits as a shield against revenue losses as well as the wider realization that natural gas development is not a long-term solution for anyone. He cites additional difficulties in developing the Marcellus Shale, such as concerns over water withdrawals, wastewater treatment, population density, lack of fractionation plants, and inadequate pipeline infrastructure (especially in northeastern PA) to deliver the gas to markets and/or storage (Berman, 9/20/11).

In taking into account the above debate, this project aimed to add to the discussion of well productivity by examining the decline curves of a select number of Marcellus wells. No attempt was made to project their productivity beyond the present. Important variations in horizontal wells that need to be examined include the number of wells per well pad, the days each well has been online and data is reported for it, and how quickly the well declines from peak production. The number of wells per well pad varies according to the location and lease, but an impact assessment report by TNC states that industry experts expect the normal development scenario to mean 6 wells per well pad, although it could be as low as 4, or as high as 10 (Johnson, 2010). The Pennsylvania Department of Environmental Protection (PADEP) publishes production data as compiled and submitted by the industries for every 6 month period since July 2010, and for the 12 month periods of January to December 2008 and 2009, and July 2009 to June 2010 (PA DEP Oil and Gas Reporting Website—Production Reports). This analysis contributed to the study of natural gas drilling in the Marcellus by viewing it as an economy of scale, and the relative factor of pipeline construction and maintenance that is necessitated by the industry. If more wells are drilled on a single well pad, this will have significant implications on the amount of pipeline that is needed to transport the gas to larger main pipes, and will have commensurably smaller impacts on land and water resources. On the other hand, the rapid decline of wells may signify a shorter lifetime production period. Instead of the industry's claims of 45-60 years of natural gas flowing, we may see that the majority of wells in the Marcellus play are not as generous in their output, and we are then faced with a tangled maze of high diameter, high pressure pipelines that have a lifetime of 50 years (Folga, 10/1/11) serving wells that peaked well before their warranties were up.

IV. Study Area

The study area consisted of 9 watersheds (35.11 km^2) that were sampled by Anderson in his pilot study on the impact of drilling densities on surface waters. Three of the watersheds are reference (R) and have no drilling, three are low density (LD) (0.39-0.61 wells/km^2), and three are high density (HD) (0.75-2.38 km^2) (ANSP, 5/2/11).

Watershed	Active wells (July 2010)	Watershed Area
LD1	2	3.3 km^2
LD2	1	1.75km^2
LD3	1	2.59 km^2
HD1	6	2.38 km^2
HD2	9	4.96 km^2
HD3	7	9.33 km^2
R1	0	1.84 km^2
R2	0	3.33 km^2
R3	0	5.63 km^2

Table 1

Eight of the watersheds are conjoined and in the vicinity of the town of Dimock in Susquehanna County. R3 is approximately 24 km south in Wyoming County. The area is depicted below. Twenty-two pads and their pipelines were later identified and marked (see Results section).

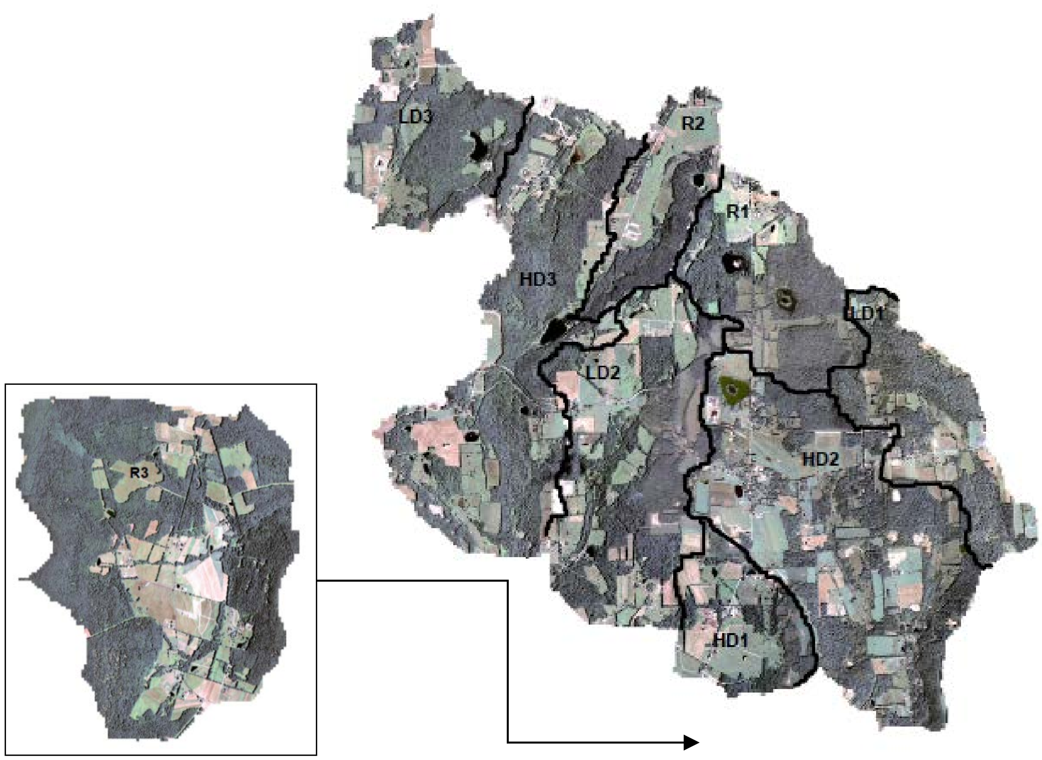


Figure 4: The study area

The interstate Tennessee Gas Pipeline (TGP) is also located approximately 1 kilometer south of HD2. The 300 line is experiencing upgrade construction as part of a regional project to transport an additional 1 bcfd of natural gas alongside its normal capacity (Tennessee Gas Pipeline: an El Paso Company, 4/2/12).

Figure 5: The TGP running across PA-29 (approximately 4 kilometers from Dimock on 29). (Tennessee Gas Pipeline: an El Paso Company, 4/2/12).

It is assumed that the gathering and transport lines in the vicinity of Dimock ultimately link to the TGP for transport out of the state.

V. <u>Methodology</u>

Many of the studies on natural gas drilling in the Marcellus Shale are generalized in scope and implications, but this project sought to contextualize the effects of drilling by focusing on data already gathered by Frank Anderson and the Academy of Natural Sciences in its pilot study of surface water impacts. The original project design included 3 reference sites, 3 sites with high density drilling, and 3 sites with low density drilling. The preliminary study suggests that high density drilling affects water chemistry as well as macroinvertebrate populations, and this project offers several opportunities to build off of this data while enriching it (ANSP, 5/2/11).

a. <u>Mapping of Pipelines</u>

The mapping of the pipelines and the pads throughout the watershed proved to be challenging due to the ambiguities associated with the satellite imagery. For the pads, a combination of techniques was used. In some cases, visual confirmation was enough. In others, suspected pads were marked as wells on ShaleNavigator ®. Finally, in pursuing the economy component of this project, other well pads in the study area were confirmed (e.g. Heitsman 4H in HD1). A spatial data layer of state wells and their spud date (the date on which the drilling begins), as found on

FracTracker ® and originally published by the PADEP, was also used to confirm well pad locations (Anderson, 3/26/12). It must be stressed that no single method provided a complete record of the well pads in this area. ShaleNavigator ® arguably did, but it took into account all well pads constructed into the present, while my project only wanted to focus on those that existed in 2010. All confirmed well pads were marked with a number according to their order (right to left, top to bottom).

In order to map the pipelines within the watersheds, as well as the pipes extending off the pads out of the combined area, two different strategies were utilized. One was the use of satellite imagery and GIS data, and the other was to physically go to the study area and confirm or deny the existence of pipelines. For the former method, three different services were used. The base layer of satellite imagery was downloaded from the United States Geological Survey (USGS) Seamless Server, which is taken from the National Agricultural Imagery Program (NAIP). The NAIP data is orthoimagery corresponding to Zone 18 of the state of Pennsylvania's Quarter Quadrangle. With a one meter ground sample distance and +/- 5 meter horizontal accuracy, the matching of watershed area to satellite imagery is believed to be competent. The date of the satellite imagery, July 2010, corresponds to the same month during which the samples for the pilot study by Anderson were collected. Additionally, Google Earth® and ShaleNavigator® were used to locate pads within the watersheds and compare terrain images, as suspected pipelines in the NAIP satellite imagery would sometimes be much more clearly delineated in the other two programs. Care was given to distinguish what looked to be a pipeline right-of-way from other structures such as powerlines or contours in agricultural land.

Additionally, the author traveled to Dimock, PA in order to confirm or deny the existence of several pipelines. According to the Argonne National Laboratory, many pipelines are built alongside roads or in other easily accessible places in order to allow for maintenance (Folga, 10/1/11). This statement guided efforts to locate pipelines while in the field. Before traveling there, the longitudes and latitudes of different points along roads in the area were marked to determine if a pipeline was running across it or alongside it. Maps of the watersheds from ShaleNavigator® also abetted the process, marking the probable location of each pipeline in order to have a visual with which to guide the investigation. GPS coordinates were mostly superfluous, as the overall area was quite small, and pipelines relatively easy to spot. By virtue of their bright yellow posts, many pipelines were identified just by driving through an area of interest. Other times, an above ground valve would belie the underground infrastructure. In driving by drilling pads, natural gas pipeline posts could often be spotted. The fieldwork was an excellent opportunity to differentiate between curves on the ground that could only be guessed to be pipelines from the satellite imagery. These included petroleum pipelines, fiber optic cables, powerlines, and simply contours in the land. Still, some pipelines remain unconfirmed; more likely, sections of a pipe remain unconfirmed while the rest of the length can be identified with confidence. This is due to a number of reasons, including absence of markers on the ground while they appear quite likely in the satellite, my inability to access much of the area not on the roads, as much of it was private property, and, in one instance, confirmation on the ground that does seem to match the satellite imagery. Unlike the strategy described above, this method was only used to confirm the pipelines within the watersheds. Due to an earlier error in the location of LD3, pipes within this watershed were not explicitly investigated. Likewise, there was an error in the locating of R2 as well, although it was found to lie within the area of the original HD3 watershed where no pipelines were found to exist, and so the analysis was not affected in this regard. Overall, the mapping of pipes within the designated watersheds is a conservative estimate of their total lengths.

Complications and error associated with the mapping of pipelines and this methodology include the obvious discrepancy between the July 2010 satellite imagery used for analysis and the later 2011 and 2012 dates of Google Earth® and ShaleNavigator®. If a drilling pad was recognizable, it was assumed that pipelines had been built for it. In some cases, it became clear upon observation that pipeline construction had not taken place yet, and only the ones in existence were marked. Some pipelines were especially hard to map since they are older and covered with vegetation, or they run alongside runs or bend around development. To resolve this issue, the timeline feature in Google Maps was used to set the satellite imagery date from 10/6/2011 to 10/16/2008. Many pipelines that were in question before were confirmed or denied based on whether they were seen to be in construction or healing over in the earlier 2008 date.

In the final mapping of pipelines, all watershed satellite imagery was analyzed with ArcGIS. For each watershed, lines demarcating pipeline segments as they ran from pad to pad were drawn across watersheds, and out of the watershed bounds. Confidence level of pipe segment path is signalized by color. Black pipelines denote the highest confidence level, while the blue pipelines denote locations that were not as obvious as the black. The light blue line, seen once in HD2, is the least certain pipeline section; while fieldwork confirmed a pipeline along this road, there could have been a mistake in recording. The pipeline crossing may actually be further south of its suggested location.

Another interesting aspect explored was the length of pipeline exclusive to each well pad in relation to its order in the gathering line system. For this, only Pads #3-16 were concentrated upon, as they constitute a hub of gathering line connections that ultimately ends after Pad #6 connects to a larger transport line, which then runs south to the Tennessee Gas Pipeline. Pad position was determined by measuring the length from the first well pad (i.e. one with no gathering lines running into it, and only ones running out of it) to the second well pad. Gathering line measurements were repeated from pad to pad until they inevitably came to end after Pad #6.

b. Environment

After the pipelines had been drawn, an assay of how pipelines could have impacted deforestation within each watershed was undertaken. To do so, the forest cover of the 2010 watersheds was compared to the 2005 forest cover of the same areas. The 2005 date was chosen because it is before the natural gas drilling boom began in the region in 2008 (Maykuth, 4/11/12). For the 2005 forest cover, NAIP satellite orthoimagery was again utilized, although the imagery from this year has a different pixel size. Whereas the 2010 images had a cell size of 1 meter by 1 meter, the 2005 images had a cell size of 2 meters by 2 meters. As is discussed in the Results section, it may have had an impact on accurate classification.

In determining forest cover, the Image Classification toolbar in ArcGIS was used, which allows users to delineate distinct land uses and land cover classifications where categories did not previously exist. Using the supervised method, 20-30 training points at a minimum for both forest cover and non-forest cover were identified. Due to the various shades of green in the imagery caused by trees as well as shrubbery and grass, there was typically a moderate degree of overlap between the resulting classification grid. To mitigate this, the Focal Statistics tool was utilized so that every pixel within the satellite image took on the value (i.e. forested or non-forested) of the majority of its 7 neighbors. This smoothed out much of the "noise," so that large patches of forest and cleared fields were rightly classified as forest and development, respectively. For those areas which still had a large number of forest pixels where non-forest pixels should exist, or vice-versa, polygons were created. Drawing polygons, rasterizing them, and classifying them according to their rightful forest or non-forest values enabled the further refinement of the grid, and in some instances, set off non-forested areas that would have otherwise been highly fragmented and not representative of a developed clearing.

Water was a third category factored into the image classification. This element did not usually have as many training points (a minimum of 4) due to smaller bodies of water in some watersheds. In the resulting classification grid, the black reflection of the waters also meant that shadows of trees and buildings were categorized similarly. Regardless of this result, whether it was water or shadows, it was ultimately factored into the non-forested ratio.

The forest cover to non-forest cover value was ultimately ascertained by opening the attribute table of the final grid and simply taking the percentage of the forested pixels as compared to the total. This process was first performed on the 2010 watersheds, and then repeated for the 2005 satellite images of the same watersheds. The end results of both were compared in order to observe the forest cover change over the 5 year period.

To get a final estimate of what percentage of this impact could be attributable to pipeline construction, the total length of the pipeline within each watershed *that was found only in forested areas* was multiplied by 2 or 3 different possible right-of-way widths. It was then ascertained what percentage of total non-forested area this pipeline area was for each watershed as of 2010. The different right-of-way lengths included 30 feet (9.144 meters), 50 feet (15.2 meters), and calculations of right-of-ways widths based upon total percentage of forest loss. These numbers were chosen for two reasons. First, The Nature Conservancy estimated that gathering lines for a Marcellus well are anywhere from 30-150 feet, and found that in Bradford County, a right-of-way of 100 feet was prevalent, and in other instances, at least a 50 foot right-of-way was kept free of vegetation (Johnson et al., 1/9/11). Second, measurements of two pipeline crossings in HD3 yielded right-of-way widths of 10.2 meters (33.46 feet) and 10 meters (32.81 feet). Results of these calculations were then compared to change in forest cover.

c. <u>Energy</u>

Completing the EROI for natural gas pipeline construction and its embodied energy was difficult. The best information and best numbers were sought, but by the nature of this endeavor, results could vary widely based on low and high end estimates of these inputs.

In calculating the amount of energy used to construct the pipeline, the publication *Argonne Natural Gas Pipeline Technology Overview* was consulted. This had a chart which broke down the daily emissions (by pound) of the machinery utilized during pipeline segment construction. Construction equipment was broken down into several categories, including whether they were gasoline or diesel-powered, and carbon monoxide emissions were used for approximating fuel consumption. Two emission totals were tallied, one for diesel consumption and one for gasoline consumption. Fugitive emissions from disturbed acreage were not included in either total (Folga, 10/1/11). Standard conversion factors were used throughout, and came from the Units and Conversions Fact Sheet published online by the MIT Energy Club (1/7/12).

For the embodied energy of the pipeline steel, three different diameters were chosen, each with a different weight and thus yielding three different energy investments. The *Argonne Natural Gas Pipeline Technology Overview* states that gathering lines are typically 0.5 inches in diameter (Folga, 10/1/11)); however, with the highly productive Marcellus shale, gathering lines tend to be much larger. The Nature Conservancy estimates that gathering lines are more likely to be anywhere from 6-24 inches in diameter (Johnson et al., 1/9/11). During fieldwork, two pipes in an aboveground valve were measured, and it was found that both measured 1 meter in circumference. This circumference means the pipeline has a diameter of 0.31 meters. Therefore, the first diameter chosen was 12 inches. The second diameter of 20 inches was chosen to match the diameter of the pipe Aucott chose to use for his analysis. Finally, 24 inches was chosen simply for its large size, to determine the maximum energy investment possible. The weights of the pipes (in kilogram/meter) varied according to diameter, but were more easily obtained from a table of pipe sizes and their attributes based on American National Standards Institute Schedule 40 (The Engineering Toolbox, 3/3/12). Finally, for the energy embodied in a kilogram of steel, the 35 MJ/kg that Aucott used in his preliminary study to draw out a possible comparison was utilized (Aucott, 9/23/11).

Finding the conversion factor from carbon monoxide to fuel consumption was perhaps the most difficult aspect of the process. Ultimately, a British Petroleum news leaflet on diesel engine emissions that found a ratio of 1 kilogram (kg) of fuel for every 30 grams (g) of carbon monoxide (BP, 1/21/12) was discovered. Gasoline also proved difficult, and the number chosen was for light truck emission rates per mile by the Environmental Protection Agency (EPA, 2/13/12). According to the EPA, for every mile driven by light trucks, they consumed approximately 0.0581 gallons of gasoline and emitted approximately 27.7 grams of carbon monoxide. Altogether the daily construction of a pipeline segment had an energy investment of approximately 3.6 billion Btus. According to the *Argonne Natural Gas Pipeline Technology*

Overview, a pipeline crew can install about a mile of pipe per day, so if we accept this, about 3.6 billion Btus are expended for every mile of pipeline installed (Folga, 10/1/11).

The choice of the well's lifetime production was difficult, since this is a highly contentious subject in any case, and drilling in the Marcellus Shale is so recent that many wells are on the younger side and could continue to produce for up to possibly 50 years (Berman, 9/20/11). As has been the pattern throughout this project, two different estimates of well production were chosen. For the high range production, 2.6 trillion Btus was chosen, which is actually on the low range of Aucott's estimates for a well's lifetime (his high value is 5 trillion). Aucott stated his reasoning as such: now that enough information has been garnered from shale wells, the 10 year production of a typical Marcellus well is expected to be 2.11 billion cubic feet, which, when extrapolated over 25 years, is equal to 2.9 trillion Btus minus the 8% of energy used to move the gas through compressor stations (Aucott, 9/23/11). Aucott did not explicitly mention if by shale wells, he meant horizontal wells only, or if he is also taking into account the production after a second round of hydraulic fracturing, as could be the case. The second lifetime production number is exactly half of the first—1.3 trillion Btus. This is based on an analysis of well decline curves by Arthur Berman and Lynn Pittinger, which stated that the ultimate recoverable reserves per well is usually half of what operators claim. Drawing upon their results, they also stated that the average lifetime production of wells in the Barnett Shale is 1.3 billion cubic feet (Bcf) (Berman et al., 11/15/12). No estimates for Marcellus wells has been issued by them yet, although Berman states the need for caution in espousing the belief in their long lifetimes and high production numbers—areas where other shale plays have failed to deliver (Berman, 9/20/11).

Now that the embodied energy for the steel, the construction costs of the pipe in place, and the productive lifetime of a well to designate the energy return were calculated, three different "rounds" of EROI analysis proceeded. The first round was simply measuring the amount of pipeline within each watershed, totaling the lengths found in each watershed, and multiplying that length by the weight and the embodied energy according to the three different diameter scenarios. Energy of construction was added to every calculation, and was produced by converting the total length of pipeline from meters to miles, which signified how many days it had taken for the pipeline to be installed. The second round had the same exact procedure (using embodied energy for 12 inch, 20 inch, and 24 inch diameter pipelines plus energy expenditures for construction) except that the total length of pipeline not encompassed all of the gathering line going from the particular drilling pad to the 300 Line of the interstate Tennessee Gas Pipeline. To do this, the “thread” of pipe across the study area watersheds had to be followed in many cases, as most pipes serviced multiple wells. For pads whose pipes went out of the watershed boundaries, Google Earth® was used to complete the pipe route to my best abilities. For one of the pads in LD2, there did not appear to be any pipelines built yet, and for 5 other pads, pipe mapping also proved to be difficult. For two pads in HD3, only part of the pipeline route to the interstate line could be mapped, and so a straight line was drawn from the point where it could no longer be mapped to the interstate line. For 2 pads in HD3 and 1 pad in LD3, none of the pipes could be mapped, so again, straight lines were drawn.

For the third round of EROI, the total amount of pipeline between pads on each of the four designated “paths” at the heart of the study area was counted (see the chart on pages 25-26). Unlike the second round of EROI analysis, the length of the larger transport pipe that leads directly down to the TGP was not included because it is outside the study area where pipelines were not mapped. At least 6 other wells outside the study area that would feed directly into this transport pipe were identified, and excluding them while counting the transport pipe length would create bias towards a higher EROI. Thus, the distance was confined from Pad #6 to the transport line. After totaling the pipeline length by path, the number of wells per pad in each path together was added. There was some difficulty in establishing number of wells per pad within the study area, and the one pad in particular which I was uncertain of was Pad #15. Through a process of elimination, Pad #15 must have 2 wells. Because it is in HD1, HD1 has 6 wells, and the number of wells on the other pads was known, Pad #15 was analyzed with two wells. There is no confirmation of this otherwise. The total number of wells was multiplied by both the low and high estimates of well productivity (1.3 trillion and 2.6 trillion Btu, respectively), and EROI analysis proceeded as with the previous two rounds. This final round of EROI analysis was performed to create what is probably the most realistic estimate for a given pipeline length and the actual number of wells that may be found along it.

There are many difficulties associated with EROI analyses, and so troubles in this aspect of the problem were not unique. Overall, there are a wide variety of numbers and data that one must cobble together, and for my analyses, a scarcity of data on the equipment used was also encountered. Three different diameters of pipelines were taken as the basis for my embodied energy for the simple fact that there is no way of knowing which diameter pipeline was buried where, or at which point a smaller diameter pipeline was fitted to a larger diameter pipeline. The various calculations were meant to get a range of possible values for gathering lines in this region, and are not supposed to be exact estimates of pipelines known to be utilized in these watersheds explicitly. Other than the two measurements of 12 inch diameter pipelines, the typical pipe size for the watersheds were not known.

d. Economy

Lastly, the production data of 54 wells in Susquehanna and Bradford Counties was analyzed. Data on well production was obtained from the Pennsylvania Department of the Environment's Oil and Gas Reporting website (PADEP, 8/24/11). Originally, only 12 farms were going to be part of this analysis, and accordingly, the 12 farms with the longest production history were picked from the Susquehanna County production reports (horizontal wells reported from January-December 2009). Susquehanna County was chosen for the simple fact that the study area is found within this boundary. Later, 6 farms from Bradford County were added to provide more depth. Again, these farms had the longest production history of horizontal wells—two wells have the earliest reporting period available of January-December 2008 while the other four report from January-December 2009. The last four were selected because they were the first four farm names in the production report list of this period with horizontal wells. Data on the wells for each farm was added Excel spreadsheets up to and including the most recent round of production data (January-June 2011). Production data for individual wells (signified by a well permit number and another well number such as 1H or 2H) was conglomerated so that every available reporting period for the well was grouped together. The daily production per reporting period was calculated by dividing the total production per reporting period by the number of gas producing days.

The next step in the analysis required a check of the coordinate locations of each well in Google Earth® to identify which wells were on the same pad, and which wells were on their own pads. Once that was identified, production data for wells over the entire lifetime of wells on that pad began to be compared. To explain more fully, production of each well over each reporting period was broken down, but kept a running count of the number of days that elapsed since the first well of the pad began producing. For example, the first well begins producing on day 0, and the second well may begin producing day 14, meaning 2 weeks after the first well. To account for an overlap in the reporting periods of January-December 2009 and July 2009-June 2010, 183 days (representing January-June 2010) was subtracted from the July 2009-2010 day count, then subtracted that number from the January-December 2009 day count. This would give the number of days that production was only the January-December 2009 value, while all the other days were the July 2009-June 2010 production value. The results for each well were put into charts according to on which pad they resided.

To gain a broader perspective of decline trends, all wells were graphed over their productive lifetime until the last reporting period. The value for the x-axis, or days, was again dependent on how many days the well went online after the first well of its pad did, and if there was no other well on the pad, the well began at day 0. Another chart was created to depict at what day each well peaked in production, and what the decline of the well (by percentage of the maximum) looked like afterwards. Four of the original wells were excluded based on reaching their production maximum only in their last reporting period or having insufficient data. The initial decline percentage (i.e. the drop-off after the reporting period of maximum gas production) was also analyzed to develop insight into how steep the decline could be for the 50 wells. Tiers of decline were arranged so that wells were grouped according to if they were producing at 90% or above of their maximum, 80-90% of their maximum, 70%-80% of their maximum, 60-70% of their maximum, 50-60% of their maximum, and below 50% of their maximum. This step was repeated for the second, third, and fourth reporting periods. Additionally, the range of both the number of days it took each well to reach maximum production as well as within each reporting period was obtained.

Finally, in an attempt to illuminate what effect, if any, the number of wells per pad has on those wells' overall productivity, each well was fitted with an exponential trendline in Excel. No intercept value was ascribed to the trendlines, and only the production data from the reporting period after the well hit its peak production was used. Each of the wells was grouped by the pad that they were on, and further categorized them according to which pads had one well, which had two wells, three wells, and so on. The average of their exponents, as indicated by the individual well trendlines, was taken and organized into a chart for comparison.

Challenges associated with this part of the project are centered on questions of representativeness. Unfortunately, the PADEP data has been under fire for inaccuracies in reporting whether a well is horizontal or vertical, and for failing to report the production data, or existence, of 12% (495) of wells in the state (Hamil, 4/7/12). The information in their datasets is organized in a chaotic and un-user friendly format that makes it difficult to distinguish between relevant and extraneous information (Kelso, 4/19/12). Additionally, there is the risk that companies may not be divulging production information that is representative of their typical Marcellus well; data may be cherry-picked from the most productive wells. As an additional caveat, my calculations of daily production do not reflect the reality of natural gas extraction. A well's initial production (IP) is usually quite high and experiences an exponential decline, and an even daily distribution of gas extraction is simply an idealized and manageable way to work with the data provided.

VI. Results

a. Mapping of Pipelines

The mapping of the pipelines and the pads throughout the watershed proved to be challenging due to the ambiguities associated with the satellite imagery. For the pads, a combination of techniques was used: visual confirmation, ShaleNavigator ®, those well pads named in the economy side of the project that were within the study area, and the spatial data layer from the PADEP. It must be stressed that none of the tools above provided a complete record of the well pads in this area at this time.

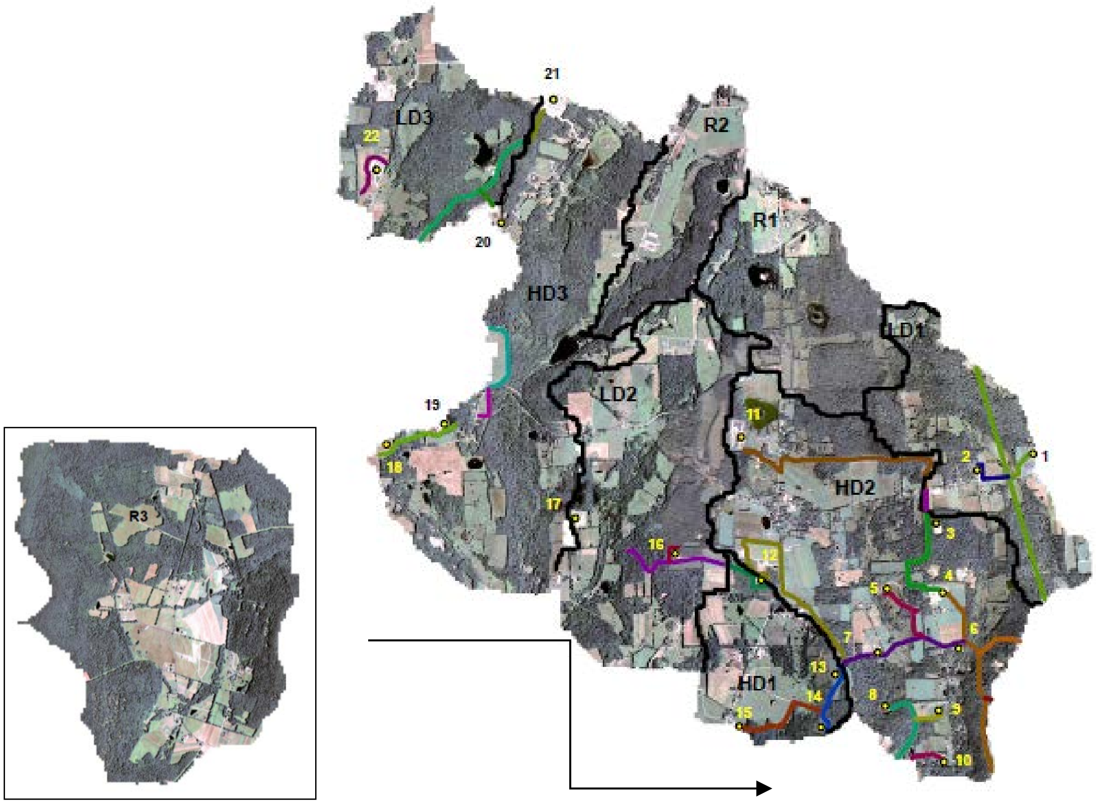


Figure 6: Study area with pads and pipelines drawn and marked.

As one can surmise after examining the image above, marking pads does not imply a pipe's locations. As in the case of Pad #17, no pipelines could be discerned, and it's not likely they had been built yet. Similar difficulties were encountered to some degree for other pads; however, confirming pipeline locations by driving through the areas in question put many suspicions to rest, as the posts warning passers-by of the pipelines are a bright yellow and easy to spot. The other method which made pipeline identification much easier was using the timeline feature on Google, which allowed me to view satellite imagery of the area in 2008. Many newly-constructed rights-of-way, still healing from their recent backfilling, appeared, and made the 2010 location of these pipes much more obvious. For depictions of the pipeline mapping in each watershed as drawn in ArcGIS, please see Appendix A on page 52.

The results are summarized in the table below. It is not surprising that the longest length of pipeline (approximately 12,000 meters) was recorded for HD2, since it has 9 well pads, each with an active well. In order to construct this entire pipeline, it would have taken crews about 7.5 days. For the rest of the watersheds with pipelines, the total was much lower, averaging 2,431 meters per watershed. It appears that total pipeline per watershed has little relation to number of active wells overall. LD1 has only 2 active wells but has more pipelines within its bounds than HD3, despite the 7 wells within the latter.

Watershed	Active wells (July 2010)	Area (km^2)	Total pipeline (m)	Construction days (1 mile per day)
R1	0	1.84	0	0
R2	0	3.33	0	0
R3	0	5.63	0	0
LD1	2	3.3	3,716.58	2.3094
LD2	1	1.75	1,368.53	0.8504
LD3	1	2.59	2,316.88	1.4396
HD1	6	2.38	2,302.00	1.4304
HD2	9	4.96	11,973.73	7.4401
HD3	7	9.33	2,453.04	1.5242

Table 2: Results for Pipeline Mapping

Another interesting aspect explored was the length of pipeline exclusive to each well pad in relation to its order in the gathering line system. For this, only Pads #3-#16 were examined, as they constitute a hub of gathering line connections that ultimately ends after Pad #6 connects to a larger transport line, which then runs south to the Tennessee Gas Pipeline. Pad position was determined by measuring the length from the first well pad (i.e. one with no gathering lines running into it, and only ones running out of it) to the second well pad. Gathering line measurements were repeated from well pad to well pad until they inevitably came to end after Pad #6. Pads #6 and #7 are repeated three and two times, respectively, in the chart below because there are three and two paths, respectively, that run through them, making them sit at a different position depending on the path. The results below reveal that the average amount of pipeline between pads decreases considerably as one moves from the outermost pad to the innermost pad (in relation to larger transport or interstate lines). Implications for land management decisions will be discussed below.

Pad's position	*Pad #	Description of gathering lines in relation to pads	Average (m)
	5	1067.52 m then hits pad 6	
	11	2,576.07 m then intersects with gathering line directly off 3	
	15	991.26 m then joins with gathering lines of 14	
1	16	1,334.66 m then hits pad 12	1492.38

	3	1238.12 m then hits pad 4	
	6	129.24 m then intersects with transport pipe	
	12	2643.32 m then hits pad 7	
2	14	723.24 m then hits gathering lines directly off 13	1183.48
	4	553.61 m then joins gathering lines directly off 6	
	7	826.79 m then hits pad 6	
3	13	465.046 m then hits pad 7	615.15
	6	129.24 m then intersects with transport pipe	
4	7	826.79 m then hits pad 6	478.02
5	6	129.24 m then intersects with transport pipe	129.24

Table 3: Results for pipeline length between pads

b. Environment:

The charts below summarize the results of the image classification for satellite images of each site in 2005 and 2010. For depictions of the results as captured in ArcGIS, please see Appendix B on page 55. The loss of forest cover was decidedly small for all watersheds, and 4 of them (R1, R2, LD2, and HD3) even experienced a slight rate of afforestation. This can be attributed to three things: 1) these are watersheds with development already present, and so the degree of forest loss over a 5 year period may be much smaller than, for example, a state forest watershed experiencing development associated with natural gas drilling; 2) the inconsistencies inherent to the image classification system in ArcGIS and a degree of subjectivity in my improvements upon them; and 3) the cell size of the 2005 NAIP imagery is 2 meters by 2 meters while the 2010 NAIP imagery is 1 meter by 1 meter, resulting in discrepancies in the sharpness and accuracy of the image classification grid results (i.e. the 2010 imagery has more pixels that could be classified incorrectly and the 2005 imagery can be classified into more rounded blocks of forest and non-forest than the 2010 imagery).

Forest Cover Classification Results				
Watershed	2005 NAIP	2010 NAIP	Change in forest cover	Forest loss attributable to pipelines (assuming 30 foot ROW)
R1	62.30%	65.60%	3.30%	0

R2	46.10%	46.50%	0.40%	0
R3	71.20%	70.60%	-0.60%	0 (no pipes)
LD1	69.40%	68.40%	-1.00%	1.50%
LD2	49.20%	50.50%	1.30%	0.47%
LD3*	63.70%	60.50%	-3.20%	1.27%, 2.12%, 3.2%
HD1**	36.00%	34.80%	-1.20%	0.41%, 0.68%, 1.2%
HD2	52.30%	50.60%	-1.70%	1.65%
HD3	60.80%	63.70%	2.90%	0.17%
*For right of way widths of 30, 50, and 76 feet respectively				
**For right of way widths of 30, 50, and 87 feet respectively				

Table 4: Image Classification Results

For all the watersheds, potential forest loss due to pipelines was calculated. A 30 foot ROW was the assumption, as it was the smallest likely width. As with LD3 and HD1, if there was more forest loss to be accounted for, 50 feet was assumed next. If there was still more forest loss, back-calculations from the total percentage loss were performed to obtain the likely ROW width. Of course, pipeline ROW does not have to be the main source of deforestation within these watersheds—one must also consider forest losses associated with housing, industries, and even natural gas drilling pads. However, all forest losses in the LD and HD sites could be attributed to pipeline presence in formerly forested areas, even with a ROW width that is well below the typical 100 feet described in Johnson et al (1/9/11). In the two watersheds that had a slight afforestation, LD2 and HD3, the percentage that could be attributed to pipelines was less than half a percent, supporting the idea that the presence of pipelines could be tied to forest losses.

c. Energy

The results of both rounds of EROI calculations indicate that natural gas pipelines do indeed constitute a very small percentage of overall energy investment. They are as follows, and take into account both my estimate for energy expenditure for construction (3,577,914,041.87 Btu/day) as well as embodied energy for the steel used in the pipes of different diameters. For more information on how these calculations were performed, please see Appendix C on page 64.

1) For pipelines within each watershed:

LD1

Total pipeline (m)	Days to build	Pipe size (in.)	Embodied Energy (Btu)	Construction costs (Btu)	Well productivity (Btu)	% of energy return
3,462.96	2.1518	12	9,163,892,822.98	7,698,955,435.30	2.6 trillion	0.65%
					1.3 trillion	1.30%
		20	21,028,589,460.27		2.6 trillion	1.10%
					1.3 trillion	2.21%
		24	29,234,391,946.74		2.6 trillion	1.42%
					1.3 trillion	2.84%

LD2

Total pipeline (m)	Days to build	Pipe size (in.)	Embodied Energy (Btu)	Construction costs (Btu)	Well productivity (Btu)	% of energy return
1,368.53	0.8504	12	6,664,149,417.40	3,042,658,101.21	2.6 trillion	0.26%
					1.3 trillion	0.51%
		20	11,352,975,080.40		2.6 trillion	0.44%
					1.3 trillion	0.87%
		24	14,595,837,368.42		2.6 trillion	0.56%
					1.3 trillion	1.12%

LD3

Total pipeline (m)	Days to build	Pipe size (in.)	Embodied Energy (Btu)	Construction costs (Btu)	Well productivity (Btu)	% of energy return
2,316.88	1.4396	12	11,281,826,454.26	3,042,658,101.21	2.6 trillion	0.43%
					1.3 trillion	0.87%
		20	19,219,848,534.60		2.6 trillion	0.74%
					1.3 trillion	1.48%
		24	24,709,903,890.91		2.6 trillion	0.95%
					1.3 trillion	1.90%

HD1

Total pipeline (m)	Days to build	Pipe size (in.)	Embodied Energy (Btu)	Construction costs (Btu)	Well productivity (Btu)	% of energy return
2,302.00	1.4304	12	11,209,530,076.50	3,042,658,101.21	2.6 trillion	0.43%
					1.3 trillion	0.86%
		20	19,096,566,550.20		2.6 trillion	0.73%

					1.3 trillion	1.47%
					2.6 trillion	0.94%
		24	24,551,359,494.78		1.3 trillion	1.89%

HD2

Total pipeline (m)	Days to build	Pipe size (in.)	Embodied Energy (Btu)	Construction costs (Btu)	Well productivity (Btu)	% of energy return
11,973.73	7.4401	12	58,305,618,304.73	3,042,658,101.21	2.6 trillion	2.24%
					1.3 trillion	4.49%
		20	99,329,646,218.96		2.6 trillion	3.82%
					1.3 trillion	7.64%
		24	127,702,480,397.06		2.6 trillion	4.91%
					1.3 trillion	9.82%

HD3

Total pipeline (m)	Days to build	Pipe size (in.)	Embodied Energy (Btu)	Construction costs (Btu)	Well productivity (Btu)	% of energy return
2,453.04	1.5242	12	11,944,825,671.78	3,042,658,101.21	2.6 trillion	0.46%
					1.3 trillion	0.92%
		20	20,349,346,162.30		2.6 trillion	0.78%
					1.3 trillion	1.57%
		24	26,162,038,829.20		2.6 trillion	1.01%
					1.3 trillion	2.01%

As can be surmised from the above graphs, the percent of energy invested in pipelines as compared to the percent return varies widely depending on the watershed. An obvious shortcoming of this method is that watershed boundaries are not in accordance with pipeline boundaries—pipes from other pads may streak through the watershed and those pipes coming off the pads that are indeed within the watersheds are not entirely contained within this small area. Another way to look at these results is to consider the amount of pipeline per pad. The Nature Conservancy undertook a study of pipelines in Bradford County, which resulted in an estimate of

1.65 miles (2655.4176 meters) per pad (Johnson et al., 2011). If we take this factor into consideration and compare it to the amount of pipelines within each watershed, we see:

Watershed	Number of pads based on TNC	Actual number of pads	Energy expenditure with single well	Active wells *	Energy expenditure incl. all active wells
LD1	1.427	2	0.71%-3.11%	2	0.36%-1.56%
LD2	0.5154	2	0.26%-1.12%	1	0.26%-1.12%
LD3	0.8725	1	0.43%-1.90%	1	0.43%-1.90%
HD1	0.8669	4	0.43%-1.89%	6	0.07%-0.32%
HD2	4.5092	9	2.24%-9.82%	9	0.25%-1.09%
HD3	0.9238	4	0.46%-2.01%	7	0.07%-0.29%

*Based on pilot study by Anderson (ANSP)

Table 5: Summary Table for First EROI

In examining the chart above, one can call special attention to several elements. LD3 presented perhaps the most accurate assessment of EROI that can be made when looking at watershed boundaries. According to the length of pipeline within its watershed, it has approximately one pad in its watershed, and does in fact, have one active well within its area. The percentage of energy invested as compared to energy returned is in the range of 0.43% to 1.90%. This fits squarely with the 1% estimate that Aucott made in his analysis, despite these calculations going further to include energy of construction. Results are especially low in HD1 and HD3, where the small lengths of pipelines within the watershed are complemented by a high number of active wells (6 and 7, respectively). HD2 also represents a special case where the amount of pipeline is quite high (enough for 4.5 well pads according to TNC) but the presence of 9 active wells continues nevertheless drives the relative energy expenditure down to a maximum of 1% of the energy flowing out of the watershed.

2) The average pipeline distance in each watershed to connect to interstate Tennessee Gas Pipeline

This distance is reflective of the pipeline length for each pad in each watershed so that it reaches the interstate Tennessee Gas Pipeline. In doing these calculations, the entire route was measured, even if the pad's pipeline connected with another pad's gathering line and the pipe was effectively transporting two pads' worth (i.e. however many wells were on those pads) of gas production.

LD1

Avg. pipeline length to TGP (m)	Days to build	Pipe size (in.)	Embodied Energy (Btu)	Construction costs (Btu)	Well productivity (Btu)	% of energy return
4605.75	2.86	12	12188001122.689	10232834159.7482	2.6 trillion	0.86%
					1.3 trillion	1.72%
		20	27968078293.947		2.6 trillion	1.47%
					1.3 trillion	2.94%
		24	38881816794.557		2.6 trillion	1.90%
					1.3 trillion	3.78%

LD2

Avg. pipeline length to TGP (m)	Days to build	Pipe size (in.)	Embodied Energy (Btu)	Construction costs (Btu)	Well productivity (Btu)	% of energy return
7718.2	4.8	12	20424345712.454	17173987400.9760	2.6 trillion	1.45%
					1.3 trillion	2.90%
		20	46868202114.388		2.6 trillion	2.46%
					1.3 trillion	4.92%
		24	65157170576.725		2.6 trillion	3.17%
					1.3 trillion	6.34%

LD3*

Avg. pipeline length to TGP (m)	Days to build	Pipe size (in.)	Embodied Energy (Btu)	Construction costs (Btu)	Well productivity (Btu)	% of energy return
7019.75	4.36	12	18576067064.212	15599705222.5532	2.6 trillion	1.31%
					1.3 trillion	2.62%
		20	42626915834.324		2.6 trillion	2.24%
					1.3 trillion	4.48%
		24	59260844258.501		2.6 trillion	2.88%
					1.3 trillion	5.76%

*No pipelines detectable for only pad within watershed. Instead, a straight line was drawn to TGP, and this distance was used instead

HD1

Avg. pipeline length to TGP (m)	Days to build	Pipe size (in.)	Embodied Energy (Btu)	Construction costs (Btu)	Well productivity (Btu)	% of energy return
5233.508	3.25	12	13849209202.757	11628220636.0775	2.6 trillion	0.98%
					1.3 trillion	1.96%
		20	31780089564.557		2.6 trillion	1.67%
					1.3 trillion	3.34%
		24	44181355872.104		2.6 trillion	2.15%
					1.3 trillion	4.30%

HD2

Avg. pipeline length to TGP (m)	Days to build	Pipe size (in.)	Embodied Energy (Btu)	Construction costs (Btu)	Well productivity (Btu)	% of energy return
3995.28	2.48	12	10572540221.561	8873226823.8376	2.6 trillion	0.75%
					1.3 trillion	1.50%
		20	24261044096.237		2.6 trillion	1.27%
					1.3 trillion	2.55%
		24	33728219074.626		2.6 trillion	1.64%
					1.3 trillion	3.28%

HD3**

Avg. pipeline length to TGP (m)	Days to build	Pipe size (in.)	Embodied Energy (Btu)	Construction costs (Btu)	Well productivity (Btu)	% of energy return
6484.39	4.03	12	17159366574.380	14418993588.7361	2.6 trillion	1.21%
					1.3 trillion	2.43%
		20	39375981590.075		2.6 trillion	2.07%
					1.3 trillion	4.14%
		24	54741326386.465		2.6 trillion	2.66%
					1.3 trillion	5.32%

**Of the 4 wells located in this watershed, the pipelines of 2 could not be mapped and a straight line was drawn to the TGP. For the other two, approximately 4.6 thousand meters were drawn with a straight line, as a percentage of the pipeline could be mapped but not all.

The table below summarizes the results as:

Avg. pipeline length to TGP (m)	Range of ROI with single well	Watershed	Number of wells in each watershed	Range of ROI with all wells in watershed
3995.28	0.75%-3.28%	HD2	9	0.083%-0.36%
4699.5	0.88%-3.86%	LD1	2	0.44%-1.93%
5233.5075	0.98%-4.30%	HD1	6	0.16%-0.72%
6484.39	1.21%-5.32%	HD3	7	0.17%-0.76%
7019.75	1.31%-5.76%	LD3	1	1.31%-5.76%
7718.2	1.45%-6.34%	LD2	1	1.45%-6.34%

Table 6: Summary Table for Second EROI

As can be surmised from the chart above, the average distance of a pad within each watershed from the Tennessee Gas Pipeline has a profound effect on the total energy invested in that pipeline versus the amount returned. Compared to the EROI of pipelines within watersheds, this second round illustrates how much energy ultimately gained from a well would need to be sacrificed through transport to an even larger pipeline. As with the previous EROI calculation, however, this measure is not a reflection of reality. Although a pipeline may run 76 miles from its well pad and still be classified as a "gathering line" (McCoy and Tanfani, 12/11/11), it is entirely common and likely that multiple other pads will be found along its length. Therefore, the energy invested in this same strip of pipe will be considerably lowered as more wells alongside it begin producing.

3) Inter-watershed pipeline routes, with all wells along pipeline route included

First Path (#5-#6; 2 wells)

Length of pipe to transport line (m)	Days to build	Pipe size (in.)	Embodied Energy (Btu)	Construction costs (Btu)	Well productivity (Btu)	% of energy return
1196.76	0.7436	12	3166935292.534	2660536881.5350	5.2 trillion	0.11%
					2.6 trillion	0.22%

		20	7267237122.958		5.2 trillion	0.19%
					2.6 trillion	0.38%
		24	10103067484.569		5.2 trillion	0.25%
					2.6 trillion	0.49%

Second Path (#11-#3-#4-#6; 4 wells)

Length of pipe to transport line (m)	Days to build	Pipe size (in.)	Embodied Energy (Btu)	Construction costs (Btu)	Well productivity (Btu)	% of energy return
4497.04	2.7943	12	11900326454.709	9997872544.6186	10.4 trillion	0.21%
					5.2 trillion	0.42%
		20	27307944810.511		10.4 trillion	0.36%
					5.2 trillion	0.72%
		24	37964085197.372		10.4 trillion	0.46%
					5.2 trillion	0.92%

Third Path (#15-#14-#13-#7-#6; 6 wells)

Length of pipe to transport line (m)	Days to build	Pipe size (in.)	Embodied Energy (Btu)	Construction costs (Btu)	Well productivity (Btu)	% of energy return
3135.576	1.9484	12	8297541943.934	6971053868.8757	15.6 trillion	0.10%
					7.8 trillion	0.20%
		20	19040554755.387		15.6 trillion	0.33%
					7.8 trillion	0.17%
		24	26470583852.230		15.6 trillion	0.21%
					7.8 trillion	0.43%

Fourth Path (#16-#12-#7-#6; 5 wells)

Length of pipe to transport line (m)	Days to build	Pipe size (in.)	Embodied Energy (Btu)	Construction costs (Btu)	Well productivity (Btu)	% of energy return
4934.01	3.0659	12	13056661655.400	10969347765.2671	13 trillion	0.18%
					6.5 trillion	0.37%
		20	24026009420.667		13 trillion	0.31%
					6.5 trillion	0.63%
		24	41652993080.934		13 trillion	0.40%
					6.5 trillion	0.81%

The above results show that, as was the case with the other two rounds, pipelines are a very small percentage of energy investment. The results are summarized below.

Path	Pipeline Length (m)	Number of pads	Number of wells	Range of return on investment
1	1196.76	2	2	0.11%-0.49%
2	4497.04	4	4	0.21%-0.92%
3	3135.576	5	6	0.10%-0.43%
4	4934.01	4	5	0.18%-0.81%

Table 7: Summary Table for Third EROI

The longest route in the study area was Path 4, which was 4934 meters, or approximately 3 miles, and yet its range on return was not the largest because it had 5 wells, constituting a total lifetime return of anywhere from 6.5 trillion to 13 trillion Btu. The well with the lowest return was Path 3. However, Path 3 did not have the shortest pipeline length; rather, it had the largest amount of wells. Indeed Path 3 had over two and a half times the amount of pipeline length as Path 1, and yet its range of return was still slightly lower than Path 1 since Path 1 had only 2 wells. It is clear from this third round that even if some definitive bounds of gathering pipe can be drawn and compared to the drilling activity along its length, the predominant factor in energy investment in pipeline is the number of wells.

d. Economy

Production data for 54 wells in Susquehanna and Bradford Counties was analyzed to better understand the relationship between both the production peak and the trends thereafter, as well as if the number of wells per pad has any effect on production over time. To see the charts for individual wells on their well pads, see Appendix D on page 65. The chart on page 50 depicts the decline curves of each well in the order in which they come online on their pad. Production does indeed sky rocket within the first several days or weeks, then drops (sometimes precipitously) over time. To further illuminate this trend for 50 of the wells, the number of days leading up to a well's max production were plotted, and their production in the days afterwards, against the percentage of max production they maintained in those latter days. This chart can be viewed on page 51. The number of wells that maintained a certain percentage of that maximum production were counted through four reporting periods, as well as the range of days within each reporting period and the average for each. The results are summarized in the tables below:

Max daily production of 50 wells	
Range of days to reach max production	3-365
Average for days	135.72

Table 8: Days to Max Production

For the 50 wells analyzed, it took an average of 136 days for them to reach their individual maximum daily production, although the range was very large, from only 3 days to exactly a year. However, this is in keeping with the accepted idea that natural gas wells, especially those that experience hydraulic fracturing, have exceptionally high initial production (IP) numbers, which may drop quite quickly.

First reporting period		
Maximum daily production maintained	Number of wells	
Greater than 90%	5	Range of days within reporting period: 76-614
Between 80-90%	3	
Between 70-80%	19	
Between 60-70%	9	Average: 358.98 days
Between 50-60%	9	
Less than 50%	5	
Total	50	

Table 9: Percent of max production at first reporting period

The largest number of wells (19) maintained a production level that was 70-80% of the maximum at the next reporting period, which took place an average of 359 days after the well began producing. The extremes were evenly split; 5 wells had greater than 90% of their max daily production, and 5 wells had less than 50% of their maximum. Almost half of the wells (24) had less than 70% of their maximum production.

Second reporting period		
Max daily production maintained	Number of wells	
Greater than 70%	4	Range of days within reporting period: 161-798
Between 60-70%	4	
Between 50-60%	8	
Between 40-50%	**18**	Average: 546.98 days
Between 30-40%	11	
Less than 30%	2	
Total	46	

Table 10: Percent of max production at second reporting period

For the second reporting period, 31 of the 46 wells analyzed were producing less than 50% of their daily maximum, after an average of 547 days since the well began producing. The largest number of wells (18) maintained an average daily production that was between 40-50% of the maximum, while an almost even number of wells (8 and 11) produced slightly more or slightly less than this range.

Third reporting period		
Max daily production maintained	Number of wells	
Greater than 60%	3	Range of days within reporting period: 545-947
Between 50-60%	5	
Between 40-50%	6	
Between 30-40%	**18**	Average: 692.05 days
Between 20-30%	6	
Less than 20%	1	
Total	39	

Table 11: Percent of max production at third reporting period

For the third reporting period, the percentage of max daily production continued to decline so that, again, the largest number of wells (18) were producing only 30-40% of what they were initially. As was also the case with the first and second reporting periods, the category in which the largest number of wells is found indicates the highest bound for the majority of the wells. For this reporting period, 25 of the 39 wells have a production of less than 40% of their maximum daily production. These production numbers are reflective of the well's value an average of 692 days, or almost 2 years, after the well began producing.

Fourth reporting period		
Max daily production maintained	Number of wells	
Above 50%	2 (53.77, 58.76)	Range of days within reporting period: 826-1006
Between 30-50%	3 (31.41, 33.71, 33.15)	
Between 20-30%	**4**	Average: 859 days
Total	9	

Table 12: Percent of max production at fourth reporting period

For the fourth reporting period, only 9 wells had sufficient data, and had an average lifetime of 859 days. Two wells maintained a daily production just slightly above half of their maximum, three hovered just over 30% of their maximum, and the most, four wells, had sunk to 20-30% of their maximum daily production. Thus, about 2 years and 4 months after the applicable 9 wells had come online, only 2 of them were producing half of their maximum daily production. Additionally, there was a fifth reporting period for only 2 wells: Olsyn 1H and Thomas 1H. Thomas 1H reported a production value of 25.11% of its maximum by Day 1,017, but Olysn 1H was reporting an astounding 72.06% of its maximum production by Day 826. This is after the latter had experienced a decline to approximately 59% of its maximum for the fourth reporting period, and represents a true anomaly compared to any other well.

The results for the analysis of decline based on wells per pad are summarized in the chart and table below. No clear trend could be discerned in this data, as the average decay exponent for pads with 1,2,3,4, and 6 wells varied continuously. The results of this analysis again call to mind the question of representativeness. Two of the wells were excluded because an exponential trendline could not be fitted to them, and so the sample size was only 52 wells. Also, there was only one case each for 4 wells per pad (Thomas) and 6 wells per pad (Shedden), whereas there were 16 examples for 1 well per pad, 8 for two wells per pad, and 3 for 3 wells per pad. The wider question is inconclusive in its answer, as a wider sampling of wells may potentially reveal that the addition of wells to a pad does indeed decrease production. However, as the results demonstrate, no relationship is yet discernible. For a full listing of the wells and their individual decay exponents, please see Appendix E on page 92.

Wells	Average decay exponent
1	-0.00188
2	-0.00211
3	-0.00162
4	-0.00185
6	-0.00132

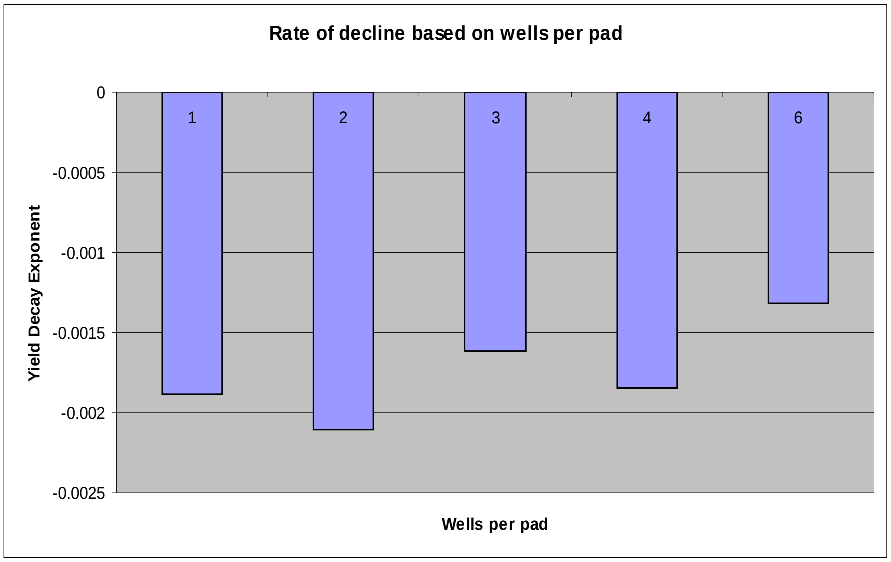


Figure 7: Bar graph depicting average decay exponents

VII. Discussion

This study was undertaken with the purpose of illuminating the role of pipelines in some of the most contentious topics of natural gas drilling—environmental impacts, energy return on energy invested, and economic longevity. The findings first suggest that neither the number of wells or well pads, nor even the size of the watersheds are good indicators of how much pipeline will be within a watershed's bounds. The watershed level is a solid unit and desirable for the study of many ecological factors, but in holding pipelines as the priority of this study, a better strategy would be to select an area along the interstate pipeline and map gathering line lengths that run into it.

The forest losses between 2005 and 2010 were less than 4% for any watershed, including the high density sites, which one could conclude means that the frenzy of natural gas drilling is having very little effect on the forested areas after all. However, the image classification technique employed is subject to inconsistencies based on the two different images (i.e. one from 2005, one from 2010) that it processed, and the cell sizes of the images were also different (2005 images were 2 meters by 2 meters and 2010 images were 1 meter by 1 meter), leading to differences in precision of landcover analysis. Regardless of the low percent of forest cover, pipelines within watershed could account for all forest losses given a ROW of less than 100 feet, which was the typical value found by TNC in its study of Bradford County (Johnson et al., 1/9/11). However, there was no marked relationship between the amount of pipeline per watershed and the degree of forest lost, as in the cases of LD1, which had a relatively long length of pipe (3,716.6 meters, or 8.9 meters per km^2) and the smallest loss of forest cover (-1%), and of LD3, which had only 2,316.88 meters of pipeline (0.001 meters per km^2) and the largest loss (3.2%) of forest. One critical reason for this disconnect is the fact that all of these watersheds have been developed to a certain extent, and so the amount of pipeline that criss-crosses through forest as opposed to fields, pastures, and other forms of private property, is proportionally smaller. This contrast between developed and non-developed can be viewed in the slight afforestation rates of both LD2 and HD3, which feature commensurably small possible impacts of pipeline (0.47% and 0.17%, respectively). LD2 had the lowest total length of pipeline for any watershed (1,368.5332 meters, or 0.001 meters per km^2) and only 448.34 meters of pipe was in forested areas. HD3 was the largest watershed at 9.33 km^2 with 2.5 thousand meters (0.004 meters per km^2) of gathering line, only 638.16 meters of which was in forested areas. Conclusively, gathering lines do contribute to forest losses in watersheds with various degrees of development, although their exact impacts depends upon the pipeline route, the pipeline ROW width, and other sources of deforestation.

At the same time, that there were very small forest losses in the 5 year period examined supports the preliminary study by Anderson suggesting that high drilling densities impact macroinvertebrate communities. Without a large loss in watershed forest, one can assume that riparian cover was not significantly damaged, and that any decrease in macroinvertebrate richness and biodiversity can be attributed to other events. With the onset of more intense drilling beginning in 2008 (Maykuth, 4/11/12), it is feasible that impacts associated with land disturbance and hydraulic fracturing had more effects on macroinvertebrate communities than loss of forest cover (ANSP, 5/2/11).

On the energy side, the results for pipeline EROI fall even lower than those of Michael Aucott in his preliminary study, even while my analysis added construction costs. The analysis in Aucott suggested the embodied energy of a portion of the pipeline needed to transport the gas from a well was approximately 10 billion Btu, and in doing so he assumed that 10 miles of pipeline (20 inches in diameter) would meet the transport demands of 10 wells. Accordingly, the energy expenditure for pipeline per well would be about 1 billion Btu, which constitutes 3% of the overall energy expenditure (30 billion Btu) to drill a well and get the gas to market (Aucott, 9/23/11). The watershed which probably best fits Aucott's scenario is HD2, whereby approximately 7.5 miles of gathering lines services 9 wells and constitutes 0.42% to 0.85% of energy returned on investment when a 20 inch diameter pipeline is installed. The total embodied energy of the watershed pipeline was 99.3 billion Btu, and the construction costs a slight 3 billion Btu; therefore the total energy invested in a pipeline needed to transport the gas from a well was approximately 11.4 billion Btu, which is indeed comparable to Aucott's 10 billion Btu. While Aucott's analysis went by pipeline per well, TNC was more interested in pipelines on the pad level. TNC found the average in Bradford County to be 1.65 miles per pad, and when examined from this perspective, this study's calculations for energy investment would actually be high if 1 well is on 1 pad. For example, LD2 has only one well and only half of the pipeline TNC dubs average, but a 20 inch diameter pipe in the watershed nevertheless accounted for 0.44% to 0.87% of the energy return. If the pipeline length were doubled to meet the TNC average, so too would the energy return estimate be doubled. While these calculations may have slightly increased the energy investment in pipelines, the degree of the increase depends upon many factors, including number of well pads, number of wells on each pad, the diameter of the pipe, and the lifetime productivity of the wells.

One perplexing aspect which Aucott did not address in his analysis was the number of wells per pad, but this data is crucial to understanding the EROI and larger questions of economy of scale within the Marcellus Shale. He assumed that 10 miles of pipeline would meet the transport demands of 10 wells, but he did not divulge how many of these wells would be occupying the same pad or if they would all be on different pads (Aucott, 9/23/11). For that reason, a second round of EROI analysis was conducted to determine the average pipeline length for each pad, regardless of how many wells were on it, within a watershed to the interstate Tennessee Gas Pipeline (TGP). Ten miles of pipeline is equivalent to approximately 16,093 meters, and in none of the study watersheds did pipeline lengths reach even half this amount, and so the energy return on investment for each watershed with a single well was at least 0.75% and even as high as 6.34%. However, the number of wells within the watershed was the ultimate factor in the energy return, revealing that all of the high density sites had return on investments of less than 1% even in the case of a 24 inch diameter pipeline, while the low density sites had returns as low as 0.44% all the way up to 6.34% (LD2 has only one well and is also the furthest from the TGP, so its return is especially high).

However, as has been mentioned, the watershed is not the best unit for the study of pipelines, so a third round of EROI was conducted to look at the relationship between pipes along a segment of a known length and the energy return of the wells along it. The third round of EROI was similar to the previous two rounds in that when all wells along the pipe route were factored in, the energy invested compared to the energy return was always quite small and less than 1%, regardless of how much pipeline was measured along the path. The second path was of special interest because it had approximately 1124.26 meters per well, the most of any of the four paths, and the maximum investment of energy was 0.92%. Meanwhile, the third path had the lowest amount of pipeline per well, which was approximately 523 meters. The maximum investment in this case was 0.43%. Of course, dwelling on these very small numbers may be quibbling--the overriding conclusion from this round as well as the previous two EROI rounds is that energy investment in pipelines for my study area is small (i.e. less than 10%) no matter which way one looks at it, and that investment decreases several times when an economy of scale emerges and more wells are added to pads along the route. It may be different for areas that are just beginning to experience drilling pressures, as their well pads may be further spaced apart, and longer lengths of pipes may need to be installed to reach more distant transport and interstate lines. However, if one assumes wells have a lifetime production over or within the range of the values on which these calculations were based, any further concentration in drilling activity will drive the EROI of even very lengthy pipeline routes down to a small percent.

Finally, the economy segment of the project revealed several interesting elements. One is that the wells used in this sample fall into line with the high development scenario TNC discussed, which is 4 wells to a pad. Of the 54 wells analyzed, 16 pads had single wells, 8 pads had 2 wells, 3 pads had 3 wells, only one pad had 4 wells and only one had 6 wells. TNC rationalized that this high development scenario would arise due to a lack of consolidation among leaseholders, and indeed these 54 wells constitute some of the earliest wells drilled in the area at the beginning of the Marcellus boom. The environmental implications for a low number of wells per pad include potentially significant loss of forest cover in undeveloped areas due to pad and pipeline construction (Johnson, 5/20/11).

TNC went further to suggest that in this high development scenario, well pads would be spaced 3,350 feet apart, which is equivalent to about 1,021 meters (Johnson, 5/20/11). While this prediction cannot be put to the test with the 54 wells selected due to their non-sequential nature, the study area lends itself to such an examination. As the chart on pages 25-26 displays, the average pipeline length between each pipe reveals a clear downward trend as the pads draw closer to a larger transport pipe. Whereas the average pipeline length for the pad that was furthest out was almost 1,500 meters, the length declined to less than half that amount between the third and fourth pads. Out of the four routes of pipeline traced in the central hub of wells in this study area, the smallest amount of pipeline (129.24 meters) belong to Pad #6, which was the absolute last pad before connecting to the larger transport line that goes directly south to the TGP. Two clear recommendations emerge from comparing TNC's high development scenario to my data. First, that leases should be consolidated wherever possible to eliminate the disturbance associated with creating new well pads and pipeline infrastructure. Secondly, spacing between pads does not have to be as high as the 1,021 meters suggested by TNC in order for a high development scenario to emerge, and therefore, the environmental and even social impacts of the siting of well pads and their associated infrastructure should be critically examined by the industry, municipal planners, and elected officials. Residents and environmentalists alike fear that major pipelines in particular create "superhighways" of development, such as the contentious Marc 1 Hub Line may inspire by connecting two interstate lines (McCoy and Tanfani, 12/22/12). This study suggests that the same phenomena could occur even at the gathering line level, as the pad furthest out could essentially invite the creation of others along its pipeline route. Currently, the legal underpinnings of Act 13, the state law calling for the imposition of impact fees on natural gas companies, is being hotly debated, as it takes away the right for municipalities to control their zoning laws in exchange for the potential windfall generated by the fees (Reed, 4/20/12). This loss in authority extends to pipeline ROW's, and so it may signal a new rush to secure leases, create well pads, and construct pipelines that encourage more drilling alongside it.

The analysis of the decline trends for the 54 wells over time suggests that while peak production is not a predictable value, a well will typically reach its maximum daily production by the end of its first reporting period, which could be as little as 3 days or as long as a year. By examining the percentage of this maximum lost over time, it was hoped to see how the debate over the longevity of wells holds up when compared to a small-scale analysis. As it turns out, the majority of those wells which have the lengthiest production data--equating to approximately two to two and a half years of actively producing days—are yielding between 20-35% of their maximum daily production. The majority of wells had declined to less than half of their maximum daily production by their second reporting period, which took place an average of 547 days after the well began producing. One noticeable trend is that while there were always above average wells with impressive production numbers, whichever category of relative decline had the most wells also marked the high end of production for the majority of the wells in that reporting period. For example, in the first reporting period, 19 wells were producing between 70-80% of their daily maximum, and the majority (42) of the 50 wells were producing anywhere from less than 50% to 80% of their daily max. For the second reporting period, 18 wells were producing between 40-50% of their daily max, and the majority (31) of the 42 wells were producing anywhere from less than 30% to 50% of their daily max. Finally for the third reporting period, 18 wells were producing between 30-40% of their daily max, and the majority (25) of the 39 wells were producing anywhere from less than 20% up to 40% of their daily max.

These results possibly suggest two things. One is that the decline of wells is fairly regular over time. This would be the case if we accepted the assumption that many of the wells constituting the largest totals and the majorities fall into the same categories as each other from reporting period to reporting period. Percent change from reporting period to reporting period for each individual well was not analyzed, and given the high variability in horizontal well production, the statement above can still be safely labeled an assumption until it is further investigated. The second assumption is that when given a number of wells and their production data, the largest total number of wells with a certain production value constitutes the upper threshold for the majority of the entire cohort examined. Thus, while the decrease may be considered precipitous, the largest number of wells favors the high end of the majority's decline.

However, a number of other factors must be considered as far as the methodology was concerned. One was the strategy for determining days. Because two reporting periods (January-December 2009 and July 2009-June 2010) overlapped, the number of days unique to each reporting period was isolated in order to continue the analysis and divide the total production by the number of days producing. As is described in my Methods section, it resulted in more days falling into the July 2009-June 2010 reporting period than the January-December 2009 one. This effects the daily production because production in general is higher in the first few days of the well's life, so by dividing higher production in the January-December 2009 reporting period by fewer days, the data reflected a huge burst in production in the first few days that dropped to the normally lower value once the July 2009-June 2010 reporting period began. As has been stated, dizzying highs in production in the first few days are not uncommon, but it must be stressed that production per day is not the reality of natural gas extraction but merely the best way to work with the data. On another note, these wells constitute a small snapshot of what is truly a wide degree of variance in production abilities. One extreme example of this is Ratzel 2H, which was not analyzed in the project because it reached its zenith in its last reporting period. According to its production data, it did not reach max productivity until Day 630, and was only at approximately 30% of this maximum at Day 36. Or, as in the case of data on Olysn 1H, production may fluctuate even as it declines so that even 382 days after reaching max productivity, it may still be producing 87% of that maximum.

Finally, there was no discernible relationship between the number of wells per pad and the productivity of those wells, as the average decay exponent increased with the addition of a well to a pad, decreased for 3 wells per pad, increased again with a 4 wells per pad scenario, and declined once more when a well pad had 6 wells. It would be harder to identify larger trends from such a small data set; additionally, that horizontal wells are often drilled at different angles from one another would suggest that well production would not suffer, at least not in the first few years of production. This analysis could still yield significant results if a larger dataset was utilized with wells that had an even longer production history and with pads that had a maximum well capacity of more than 6 (e.g. 10).

On a separate note, the decay exponents presented a puzzling piece of information in the case of the Shedden wells in Bradford County. Seven of the nine wells had the same exponent of -0.0014, which spanned two pads. The other two wells, which were on the pad with a total of 6 wells, had decay exponents of -0.0012 and -0.0011. While it was not completely unique to my dataset, as many wells had similar decay exponents, and three different sets of wells (two on Harris, and two sets of two on Thomas) had the same decay exponents, the uniformity across seven wells on two different pads on the same farm is striking. While production data may not be exact for all wells for each reporting period, it raises the question as to whether data specific to each well is purposely and meticulously recorded for each well, or if drilling companies sometimes base their production data for a well on the known production of a neighboring well.

The economy side of the project ultimately points to the potential breach between the longevity of the wells that are drilled and the pipelines that are designed to serve them. As was mentioned in the introduction, Arthur Berman discovered that wells drilled over the past six or seven years in the Barnett Shale are now not producing enough gas to pay for the cost of compressing it along the transmission lines, and that the majority of the net present value of the wells drilled there by Chesapeake Energy is during the first 5 years, and drops significantly after the first two decades (Berman, 9/20/11). This analysis suggests the same scenario could unfold in the Marcellus play as well. Meanwhile, the pipelines built for each pad have a lifetime of approximately 50 years (Folga, 10/1/11), and could remain as buried skeletons of the industry long after the gas has been extracted. The lifetime of the wells will ultimately impact the EROI so that pipelines may play a larger role in energy invested; however, their price cannot be measured in Btu alone, as forest fragmentation and impacts on biological communities may create more permanent damage than the burning of fossil fuels needed to create and lay the pipeline, and, of course, frack the well.

While this project has attempted to give a multi-faceted perspective on the environmental and economic issues facing stakeholders in the development of the Marcellus Shale, particularly the role that pipelines in it, full credit has not been assigned to the influence of the market and socio-politics that looms in the background of shale exploitation. At this moment, production is shifting from the very region in which the study area is located. In January 2012, the U.S. Department of Energy downgraded the estimates of total recoverable reserves in the Marcellus Shale from 410 trillion cubic feet to 141 trillion cubic feet, a 66% loss. At the same time in 2011 when Marcellus production grew twofold, the department was able to gather more information about the nature of the play as it was exploited, resulting in dismal news for Marcellus enthusiasts (Buurma, 1/25/12). Drilling companies received other blows in the form of a mild winter and lower demands from industries. If the Marcellus boom is considered an economic windfall for the massive bursts in production it has caused, the gas its released now gluts the energy market (D'Amico, 1/26/12). And there is no assurance that this trend will subside. The Energy Information Administration estimates that natural gas prices will be about $4 per billion Btu (or, million cubic feet) for the next two years, and that natural gas production will outpace consumption by 2021. Nevertheless, production is expected to grow in the years ahead; the CEO of Cabot Oil & Gas, for example, claims the company is still operating on a 55-60% financial return (Litvak, 1/24/12).

Yet the profitability margin in any shale play is slim, and it is a gamble the industry does not always take. In that same month, the price of natural gas dropped to $2.30 per thousand cubic feet, the lowest price in a decade, and the Energy Information Administration predicts this number will linger below $5 into 2023 (Schwartzel, 1/24/12). As of April 2012, natural gas prices have dropped below $2 per thousand cubic feet, a far cry from the $5 that energy analysts usually designate as the profitability point. Furthermore, glutted storage areas have triggered a new wave of flaring of natural gas that is not confined to the Marcellus play—up to one-third of all natural gas produced alongside oil in the Bakken Shale is now being flared (Henkel, 4/18/12). This is not a good price for which to do business, and has caused a perceptible shift in the strategy of many of the north-eastern shale's biggest producers. Chesapeake Energy, for example, plans to shift exploitation efforts to the southwestern portion of the Marcellus Shale, as well as the deeper Utica play, to extract its "wet gas." Wet gas contains ethane, butane, propane, and pentane in addition to methane, all of which can be separated from the natural gas flow to create plastics and chemicals such as ethylene. This wet gas is much more common in the southwestern portions of Pennsylvania and those areas of Ohio and West Virginia that are underlain by the shale. North-central and north-eastern PA, on the other hand, have mostly "dry" gas, which is composed of mostly methane and does not need much processing before it goes to market. In January, Chesapeake announced it would cut natural gas production by 8%, or 500 million cubic feet per day, and stall the fracking and pipeline construction of all dry gas wells already drilled. The company's prediction for the year was that over half its annual profits would come from its oil and natural gas liquids (i.e. wet gas) assets (Junkins, 1/24/12). Only 24 rigs out of a previous 47 will continue to operate in the dry gas region, and spending in the area will be cut by 70%, bringing it down to its 2005 level, when natural gas drilling had not even begun in earnest yet (Leonard and Puko, 1/25/12).

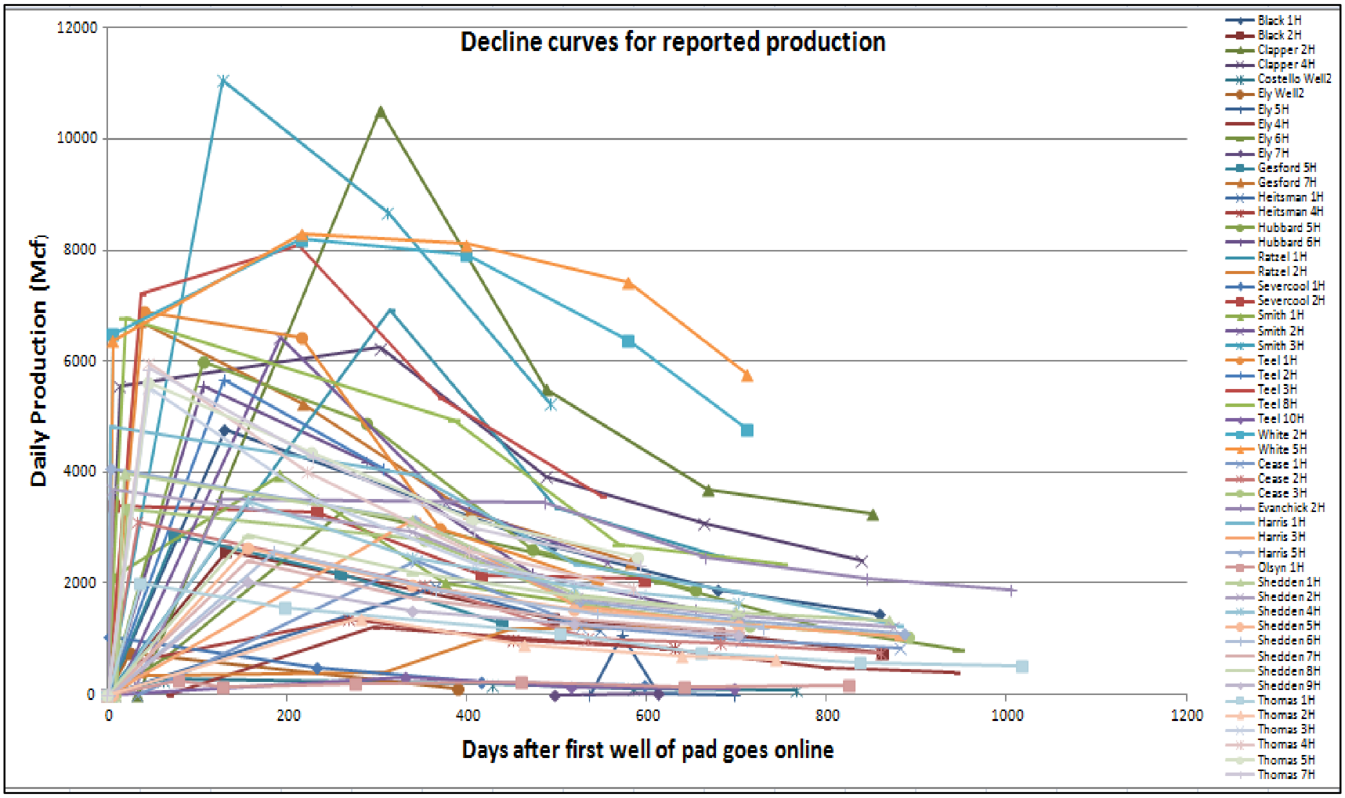
So we come to the tangle of politics, money, environment, and society that eludes any focused study such as this. Hundreds of wells in the Marcellus region have already been capped and are awaiting the transfer of their gas to markets that are already glutted, but their pipelines have not been built yet (Maykuth, 4/11/12). While companies wrangle with one another, seal deals to buy pipeline routes off another, and defend their businesses against the attacks of residents in small towns, environmentalists, and officials, thousands of miles of high-diameter, high pressure pipes, which are largely unregulated and uninspected in the state of Pennsylvania, will be laid down. These pipes will run through backyards, fields, and forests, and though hidden underground, they will cause forest edge effects and doubtlessly impact local wildlife populations. These pipes will serve wells that may see less than half of their maximum production within two and a half years, but the pipes themselves will most likely linger as underground skeletons long after the wells run dry. The lowest natural gas prices in a decade and the prospect of warmer winters mean there are already less dry gas wells being drilled, which means that the apportioned energy investment in pipelines per well may rise yet. By its nature, the natural gas industry operates on a thin profit margin and must follow the next investment opportunity, and so after a flurry of trucks, machinery, job fairs, and hysteria, the north-eastern half of Pennsylvania has come into its disfavor for being exploited so efficiently and so quickly. Time can only tell what additional changes will take place in the Marcellus Shale in general and this study area in particular, and while drilling will doubtlessly continue, there is still the chance to ensure it is done in both an environmentally and economically sound way.

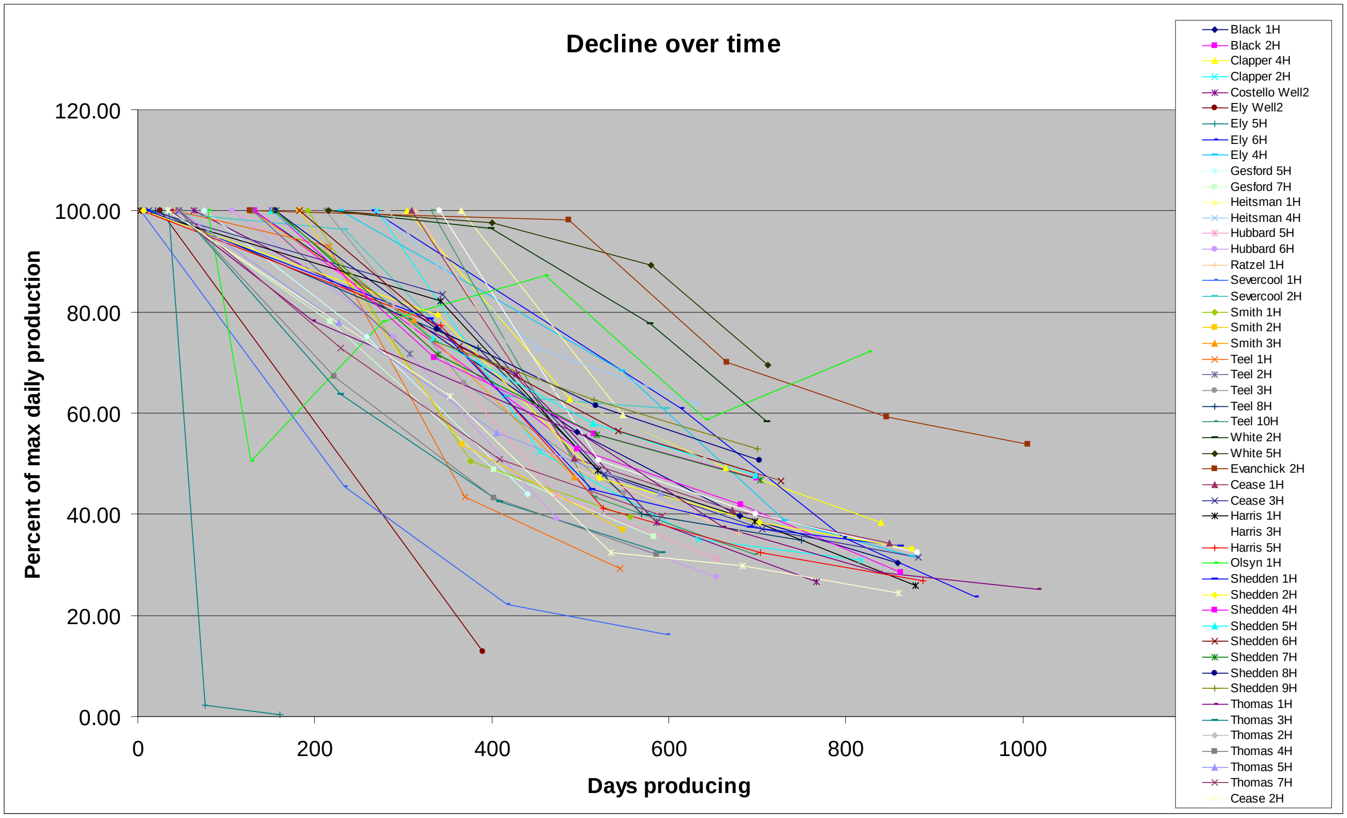
VIII. Conclusions

Forest fragmentation by pipelines is real and can continue to occur in watersheds with as little forest cover as 35%, as was the case with HD1. The high development scenario (4 wells to a pad) suggested by TNC is already unfolding according to my economy segment, but the spacing between pads within the study area is much smaller than what TNC envisioned. This implies the possibility of more concentrated impacts from creation of pads and bringing in the associated infrastructure and equipment, in addition to the actual drilling and hydraulic fracturing of the wells. This conclusion is supported by the Anderson study suggesting sites with high densities of wells had quantifiable surface water impacts and macroinvertebrate community losses (ANSP, 5/2/11).

In order to encourage wise land management practices, leases should be consolidated by the industry so that the explicit intention of well pad creation is to drill multiple wells. Not only will it exponentially decrease the energy expenditure for pipeline construction (a boon for industry), as well as the EROI for the drilling and fracking process, but it will also reduce the damages inflicted by pipelines through forest fragmentation. Municipalities and county-level officials should not be forced to renounce their right to zone well pads and pipelines through Act 13 if they feel it threatens their community’s well-being. By this, I specifically mean that the extensions of pipes in their midst could only exacerbate shale gas exploitation and result in the construction of more pads along gathering lines already in place. Multiple wells per pad would also ameliorate the negative consequences of what appears to be a steady decline for a large number of wells and a sharper decline for the majority of wells, as the surrounding environment and its organisms would not face so much land disturbance and potential damages in exchange for a short-term spike in fossil fuel extraction.

Areas for future research include a full EROI for hydraulic fracturing, as the preliminary analysis by Michael Aucott remains the only one undertaken to date. A larger and more involved study of well productivity over time would provide critics and supporters alike with a better understanding of relative costs and benefits associated with intense levels of drilling. For this study, it would be best if another source besides the PADEP reporting data could be utilized, but there does not appear to be a comparable database besides those which belong to the industries themselves. However, understanding the economy of scale in the Marcellus region will only prove to be more critical to its exploitation as time passes. More multi-faceted studies of select areas with determined boundaries should also be performed; while studies with a more generalist approach to the Marcellus question are also critical, the smaller-scale projects would eventually coalesce to give a more complete picture of the true variety we are dealing with in terms of gains, impacts, and the best strategies to maximize benefits while minimizing costs. Finally, an assessment of pipeline violations, including the location and type of violation, the responsible company, what type of pipe (i.e. interstate, transport, or perhaps gathering) was involved, and the environmental impacts would be quite revealing of yet another risk that has not yet been properly addressed in light of the Marcellus boom.

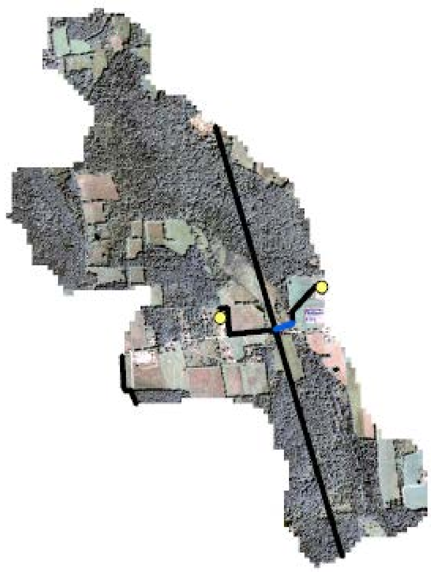

Decline curves for reported production
Daily Production (Mcf)
Days after first well of pad goes online
0
2000
4000
6000
8000
10000
12000
0
200
400
600
800
1000
1200
Black 1H
Black 2H
Clapper 2H
Clapper 4H
Costello Well2
Ely Well2
Ely 5H
Ely 4H
Ely 6H
Ely 7H
Gesford 5H
Gesford 7H
Heitsman 1H
Heitsman 4H
Hubbard 5H
Hubbard 6H
Ratzel 1H
Ratzel 2H
Severcool 1H
Severcool 2H
Smith 1H
Smith 2H
Smith 3H
Teel 1H
Teel 2H
Teel 3H
Teel 8H
Teel 10H
White 2H
White 5H
Cease 1H
Cease 2H
Cease 3H
Evanchick 2H
Harris 1H
Harris 3H
Harris 5H
Olsyn 1H
Shedden 1H
Shedden 2H
Shedden 4H
Shedden 5H
Shedden 6H
Shedden 7H
Shedden 8H
Shedden 9H
Thomas 1H
Thomas 2H
Thomas 3H
Thomas 4H
Thomas 5H
Thomas 7H


Decline over time
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Percent of max daily production
0
200
400
600
800
1000
Days producing
Black 1H
Black 2H
Clapper 4H
Clapper 2H
Costello Well2
Ely Well2
Ely 5H
Ely 6H
Ely 4H
Gesford 5H
Gesford 7H
Heitsman 1H
Heitsman 4H
Hubbard 5H
Hubbard 6H
Ratzel 1H
Severcool 1H
Severcool 2H
Smith 1H
Smith 2H
Smith 3H
Teel 1H
Teel 2H
Teel 3H
Teel 8H
Teel 10H
White 2H
White 5H
Evanchick 2H
Cease 1H
Cease 3H
Harris 1H
Harris 3H
Harris 5H
Olsyn 1H
Shedden 1H
Shedden 2H
Shedden 4H
Shedden 5H
Shedden 6H
Shedden 7H
Shedden 8H
Shedden 9H
Thomas 1H
Thomas 3H
Thomas 2H
Thomas 4H
Thomas 5H
Thomas 7H
Cease 2H

IX. Appendix A-Pipeline Mapping within Watersheds

Only the low density and high density sites are depicted because none of the reference sites had pipelines detected in them. As described in the Methodology, the highest confidence level is denoted by black, medium confidence level is dark blue, and least confidence level is light blue.

LD1



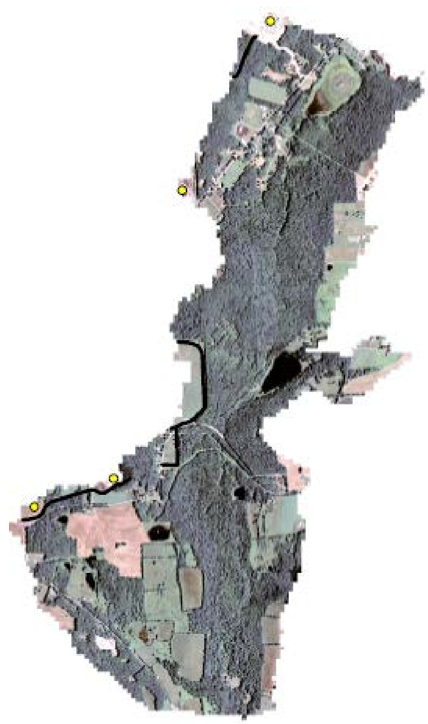
LD2

LD3

HD1

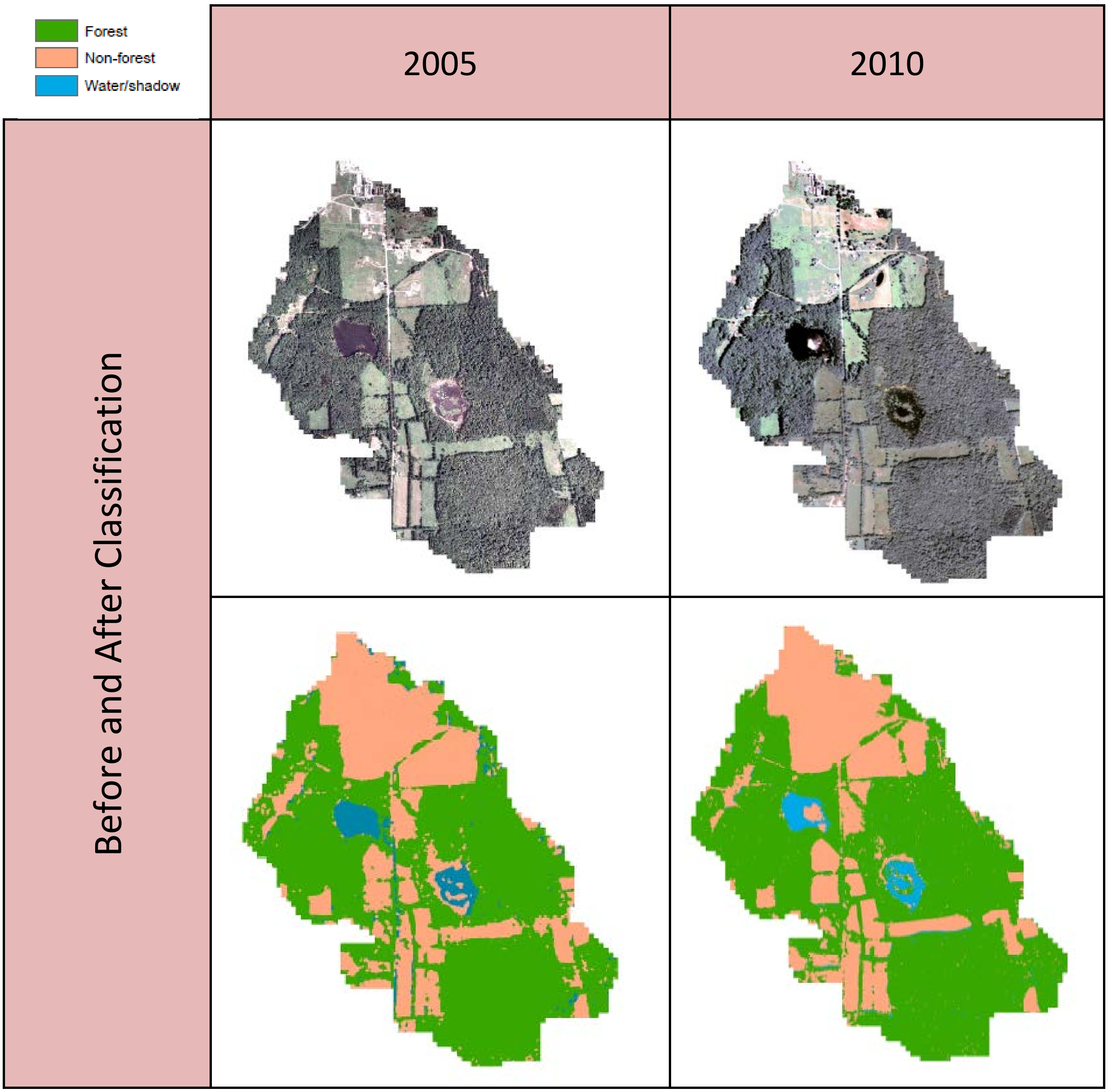
HD2

HD3

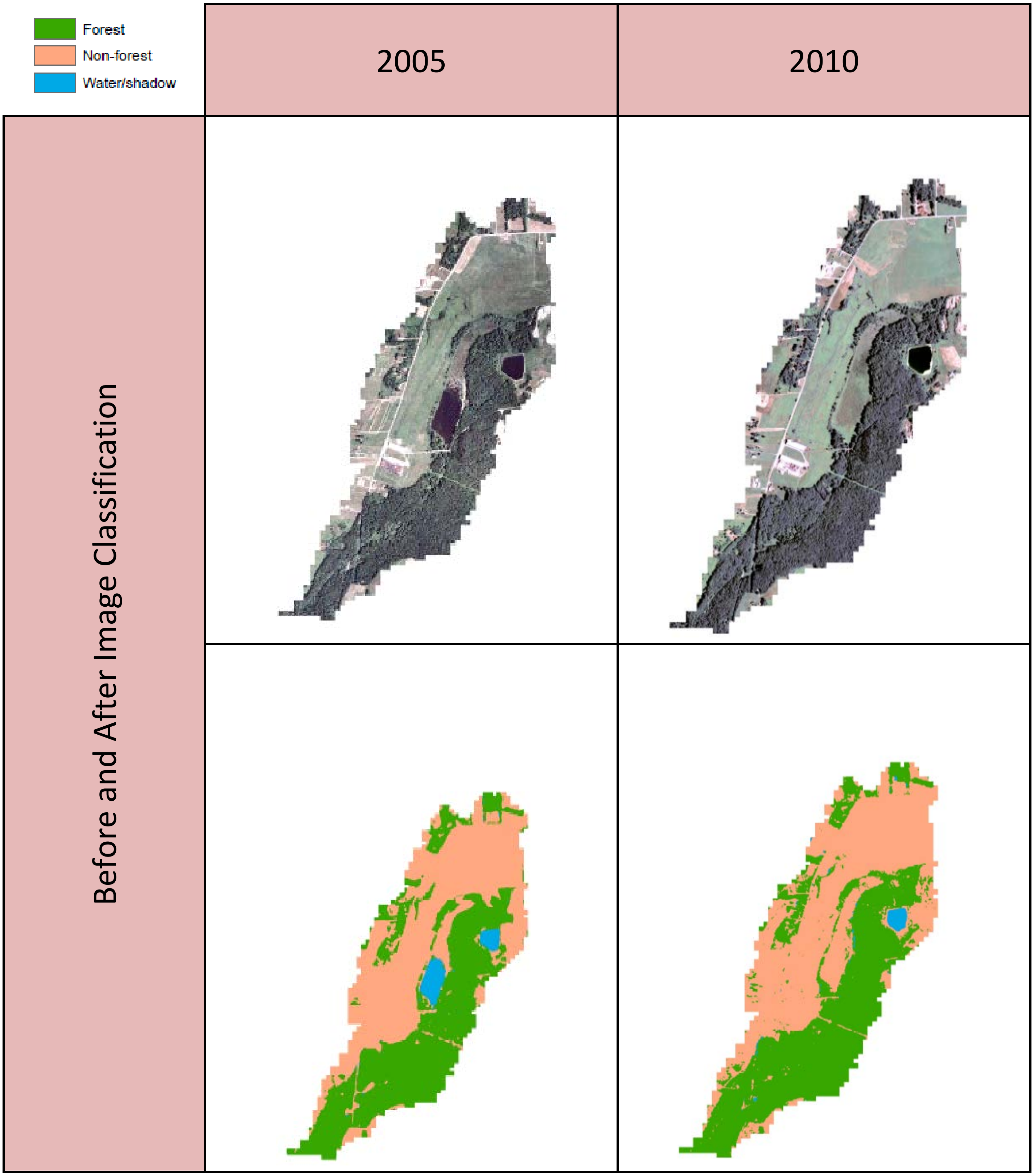


X. Appendix B: Image Classification Results

R1

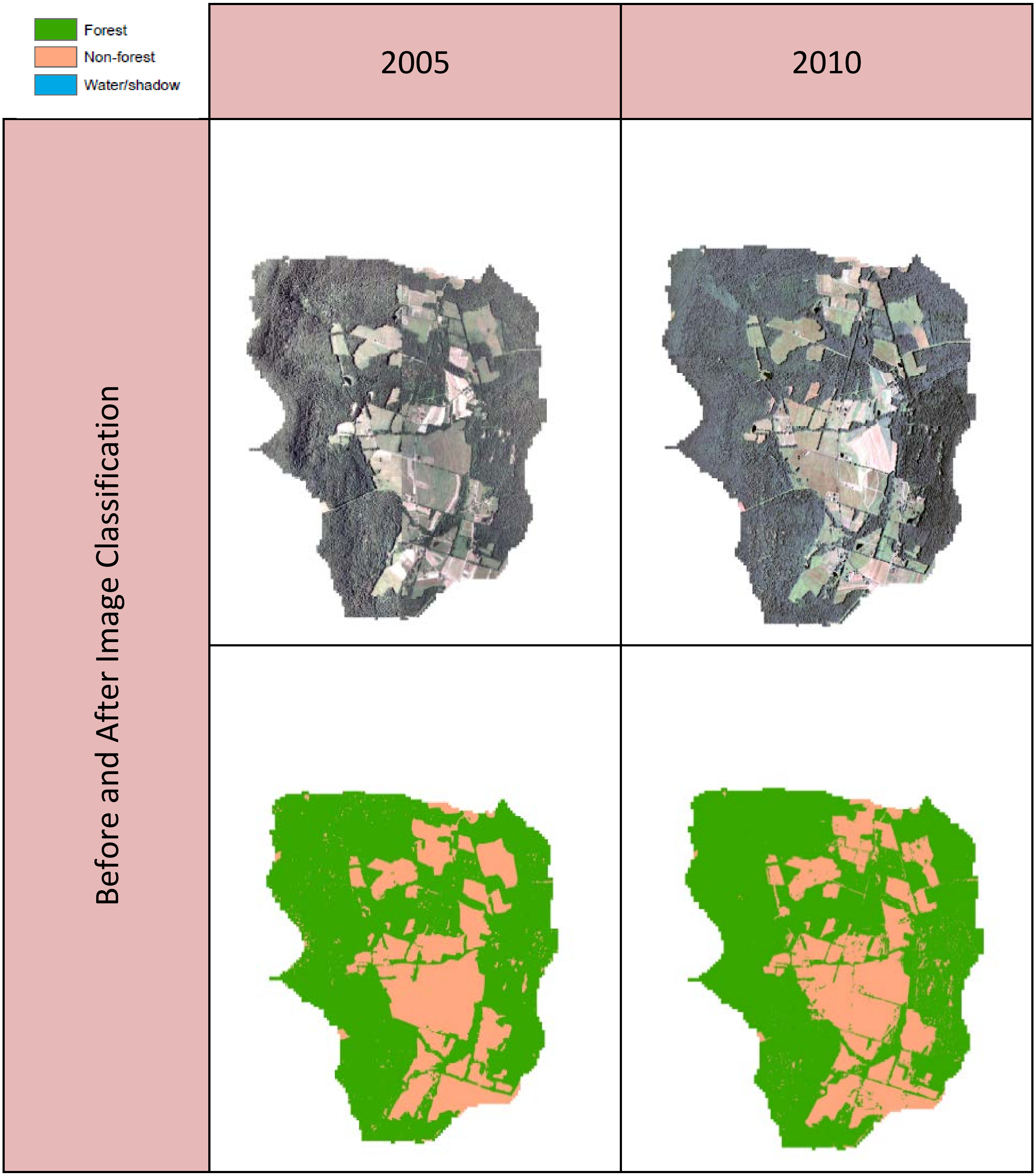


R2

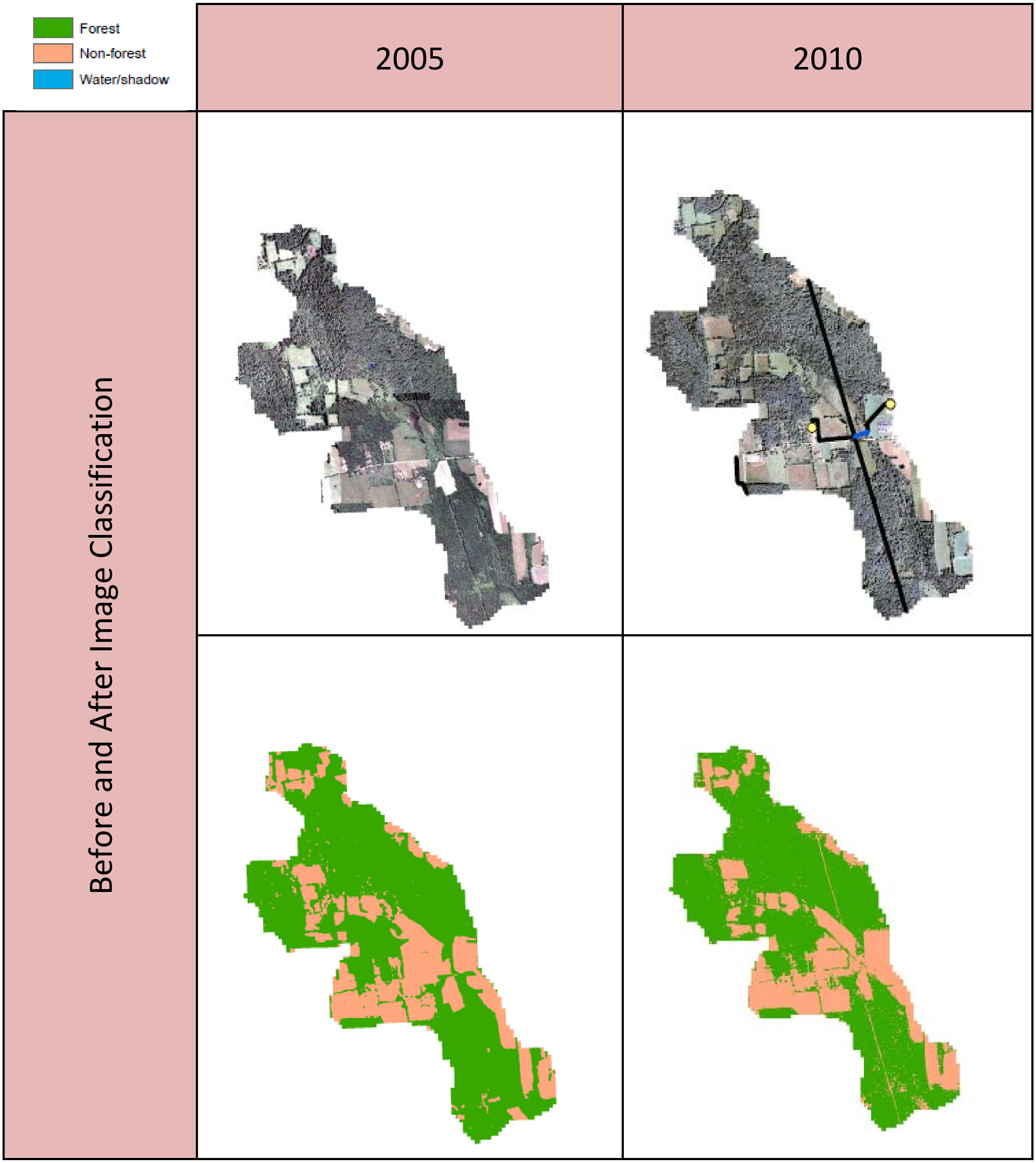


Forest
Non-forest
Water/shadow
2005
2010
Before and After Image Classification

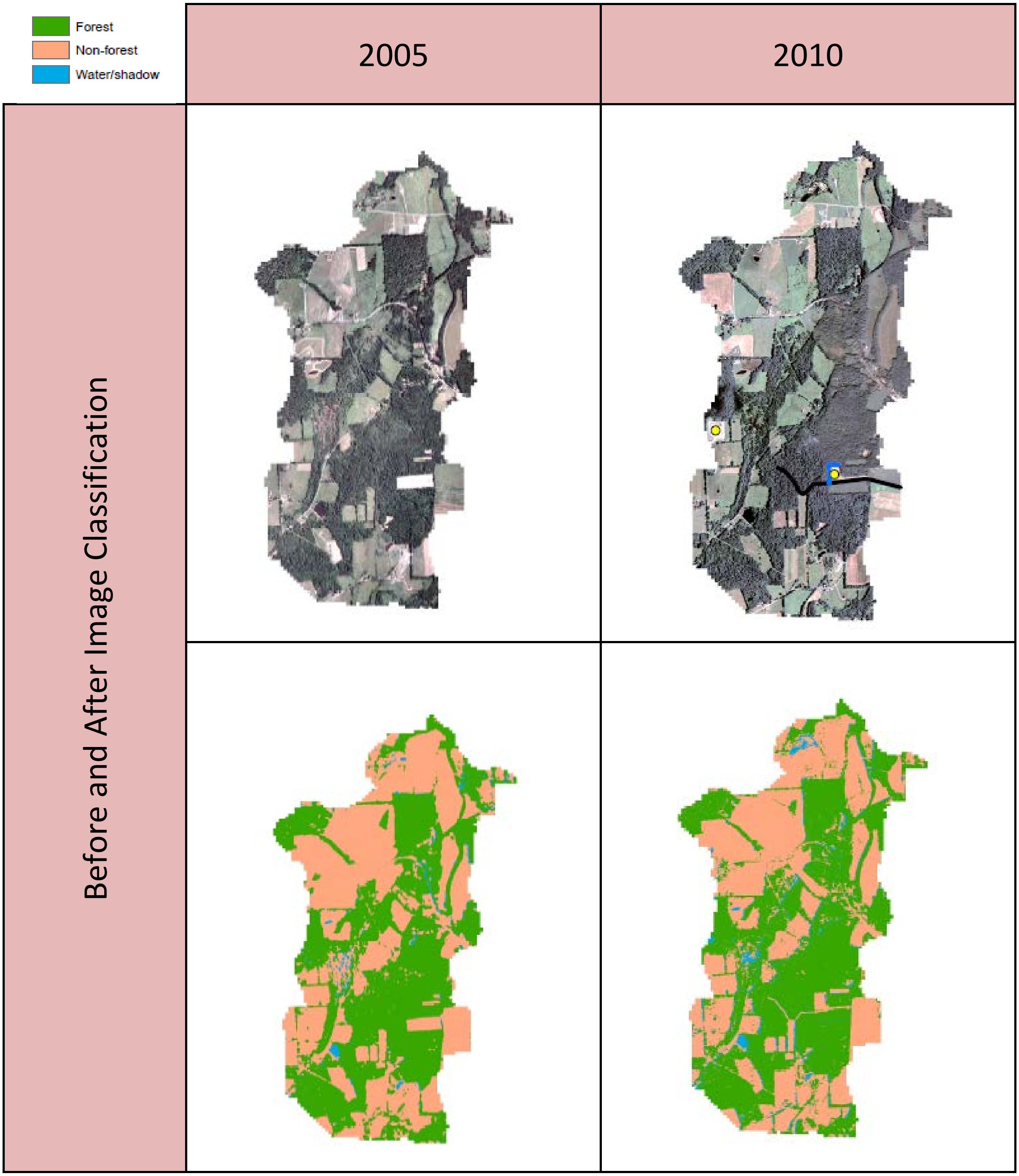
R3


Forest
Non-forest
Water/shadow
2005
2010
Before and After Image Classification

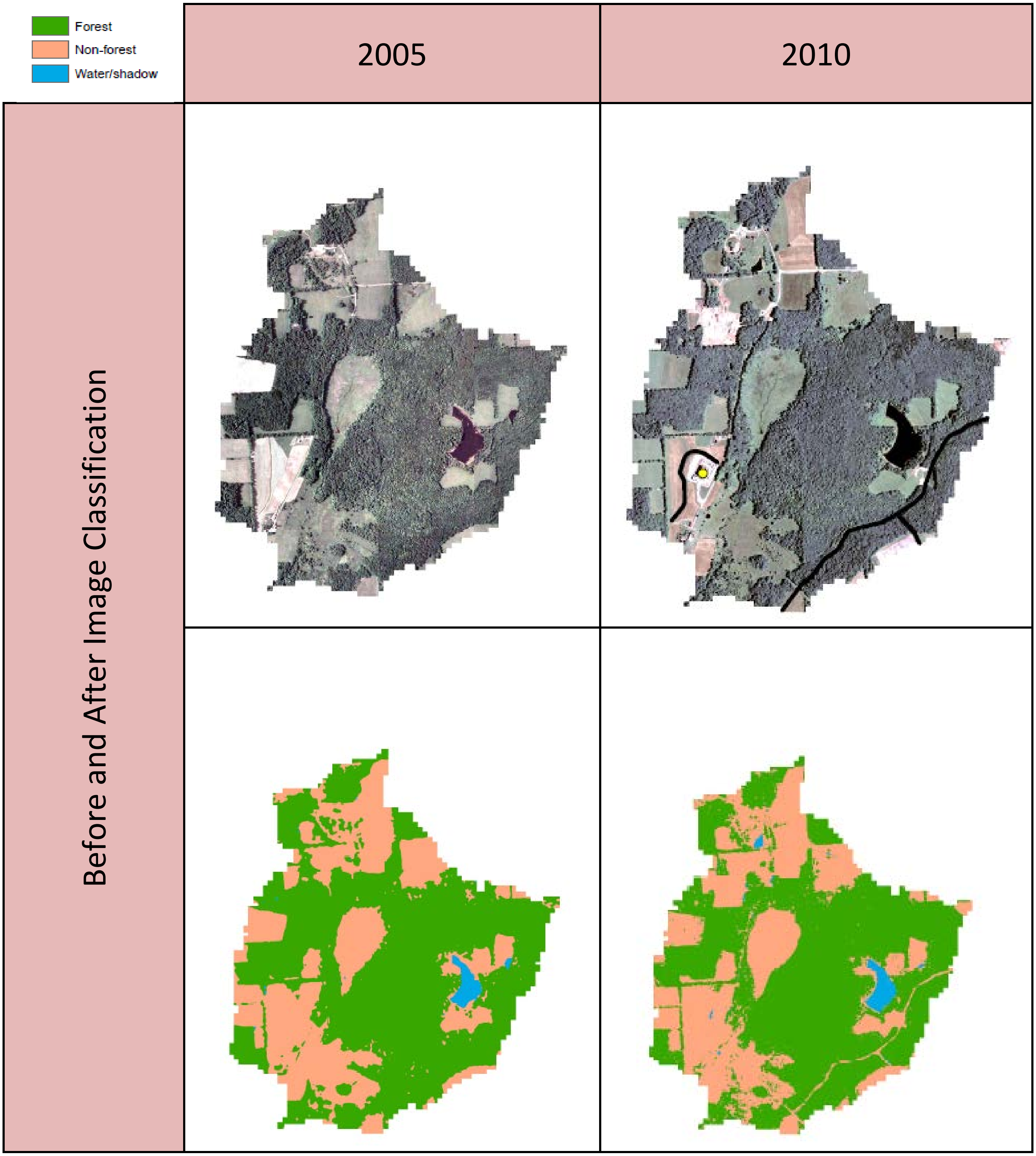
LD1


Forest
Non-forest
Water/shadow
2005
2010
Before and After Image Classification

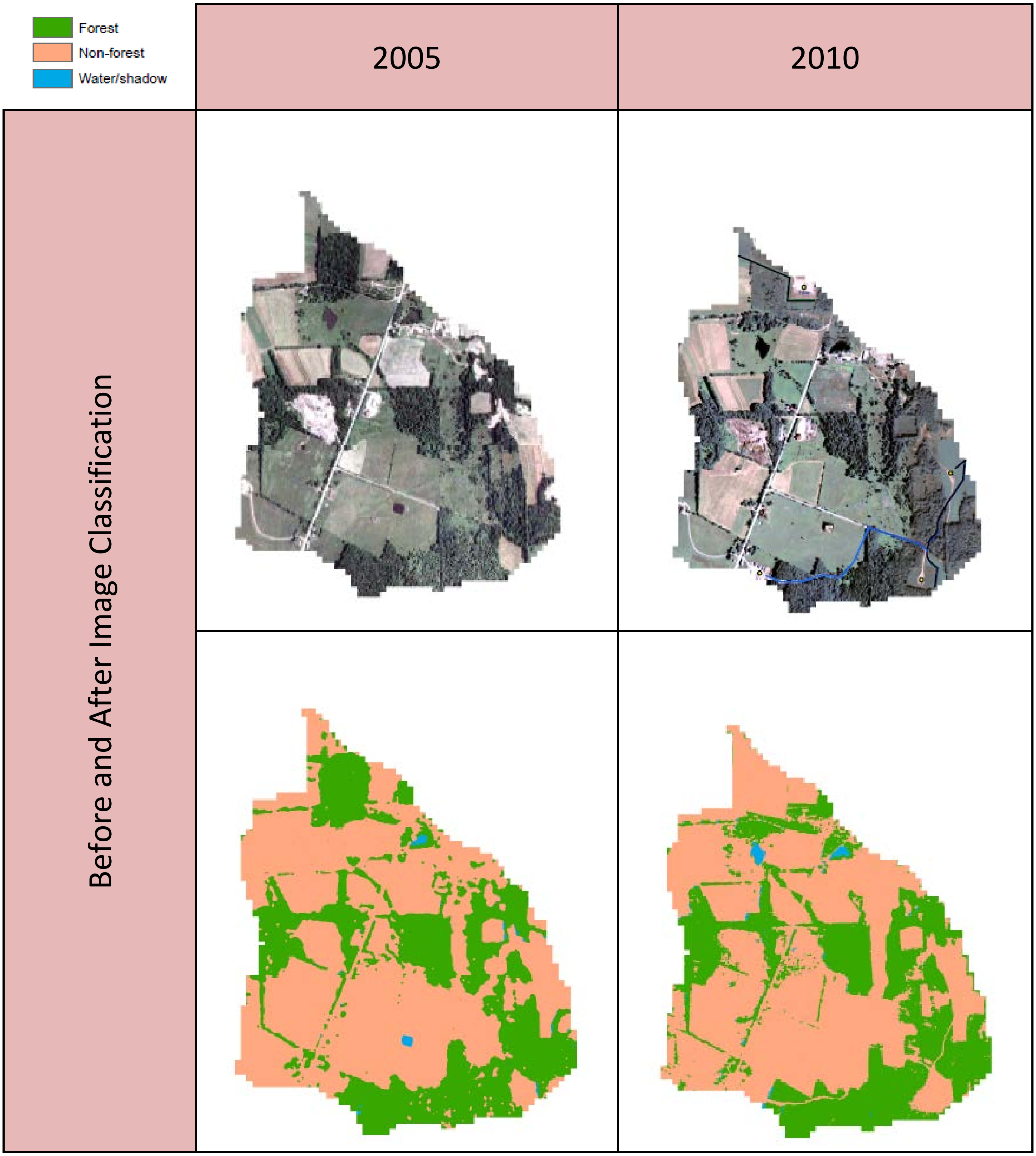
LD2


Forest
Non-forest
Water/shadow
2005
2010
Before and After Image Classification

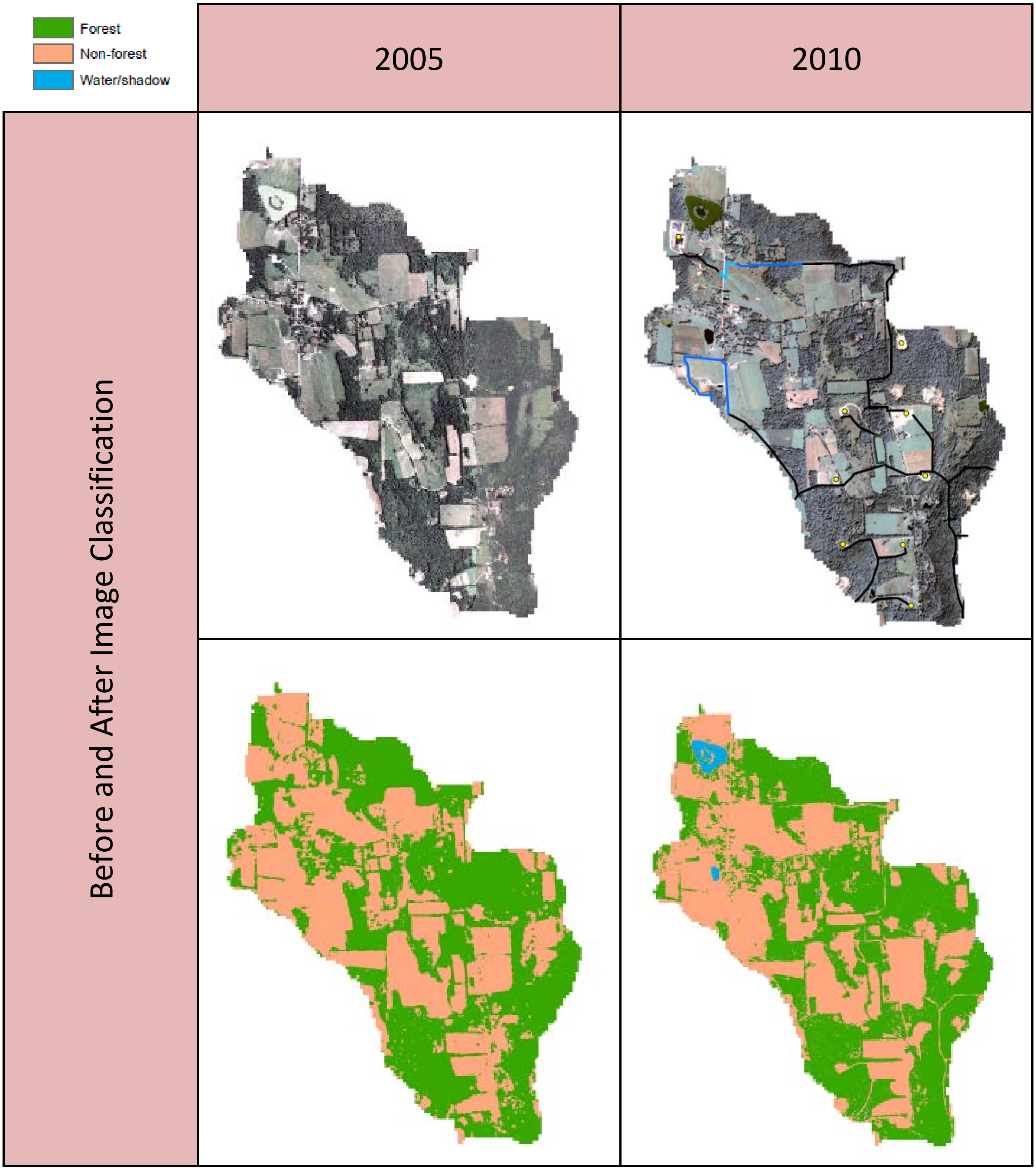
LD3


Forest
Non-forest
Water/shadow
2005
2010
Before and After Image Classification

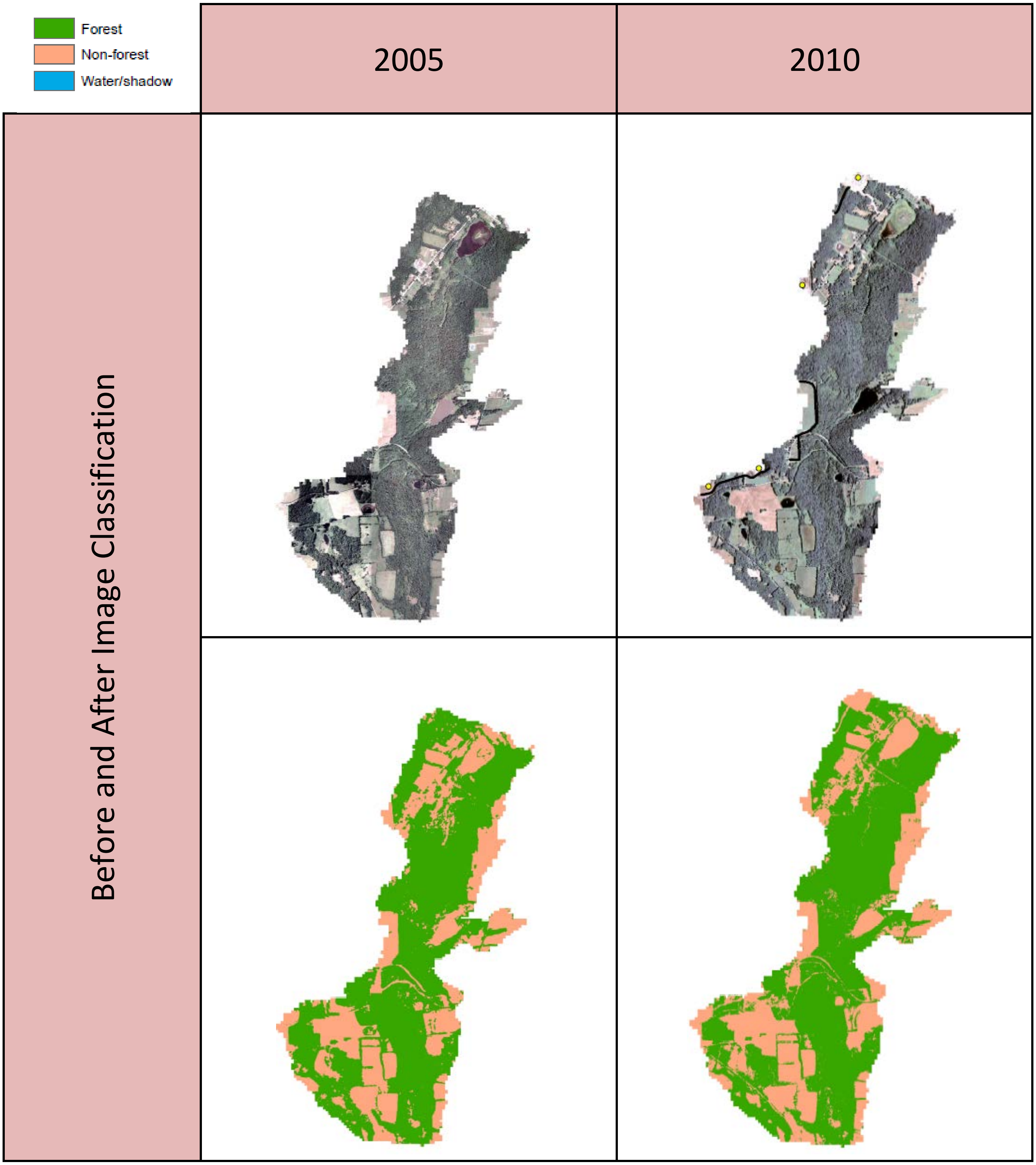
HD1


Forest
Non-forest
Water/shadow
2005
2010
Before and After Image Classification

HD2


Forest
Non-forest
Water/shadow
2005
2010
Before and After Image Classification

HD3



XI. Appendix C: Additional Information on EROI

The table below was taken directly from page 27 of *Argonne National Laboratory Natural Gas Pipeline Technology Overview* (Folga, 10/1/11).

TABLE 2.1-2 Typical Emissions from the Construction of a Pipeline Segment

	Pollutant Emissions (pounds [lb]/day)				
Type of Construction Equipment	CO	HC	NO_x	SO_2	TSP
Diesel track-type tractors	233.7	81.6	849.5	32.8	30.1
Diesel wheel-type tractors	396.7	20.8	140.2	3.5	6.0
Fugitive dust from disturbed acreage	51.6	11.6	129.4	3.9	4.2
Heavy-duty diesel vehicles	7,058.0	237.2	170.8	3.3	4.3
Heavy-duty gasoline vehicles	62.6	24.7	90.4	4.2	3.4
Light-duty diesel trucks	540.4	44.8	20.1	NA[a]	0.2
Light-duty gasoline trucks	33.3	18.3	29.8	3.7	3.7
Light-duty gasoline vehicles	10.1	1.8	1.8	NA	<0.1
Miscellaneous equipment–gasoline	437.9	55.0	29.8	NA	0.1
Miscellaneous equipment–diesel	NA	NA	NA	NA	773.0
Total	8,824.3	495.8	1,461.8	51.4	825.1

[a] NA = not applicable.

Source: EPA (2000).

The units that were used in my calculation are taken from the conversion sheet of the MIT Energy Club (1/7/12).

<u>Energy Content</u>: Gasoline=115mBtu/gallon

Diesel=128 mBtu/gallon

<u>Density of Diesel</u>=0.837 kg/L

<u>Weight</u>: 1 kilogram=2.205 pounds

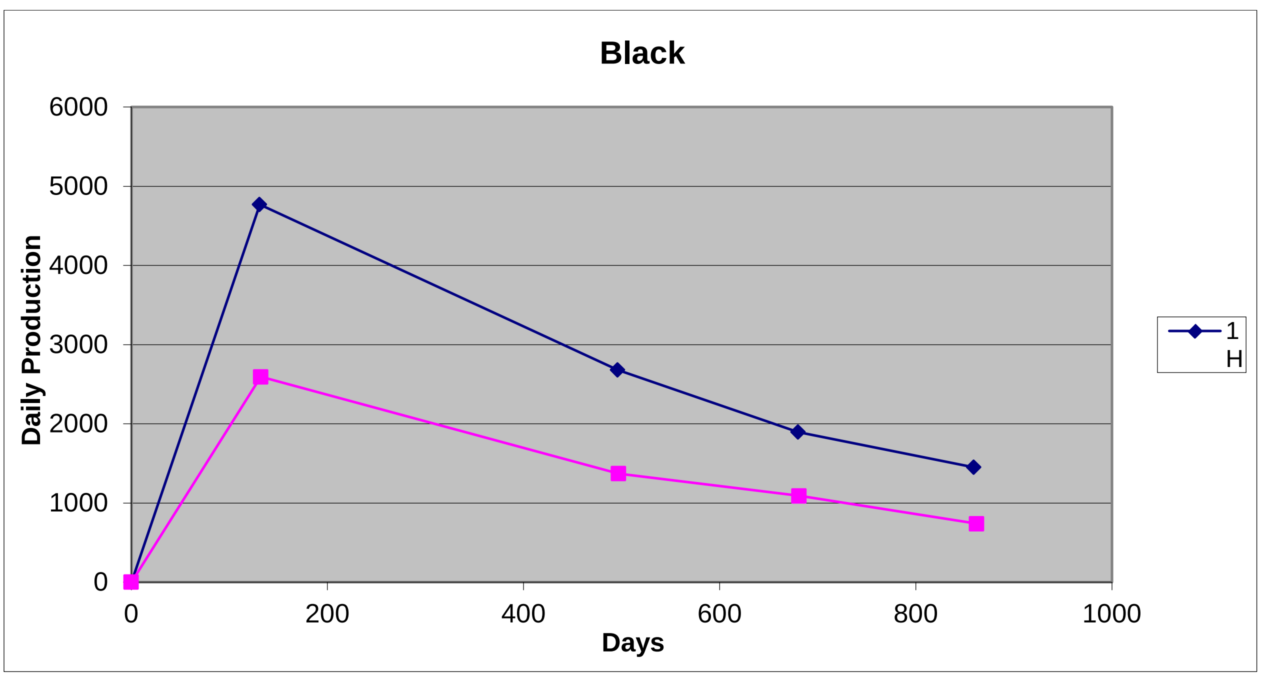
<u>Volume</u>: 1 L=0.264 gallons

XII. Appendix D: Production Data and Decline Curves

Susquehanna Wells

Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
BLACK	1H	1497453	314	**4768.959**	CABOT OIL & GAS CORP	Jan - Dec 2009 (Annual O&G, with Marcellus)
		*131 days before second reporting period (add numbers from here)				
BLACK	1H	978632	365	**2681.184**	CABOT OIL & GAS CORP	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
BLACK	1H	349005	184	**1896.766**	CABOT OIL & GAS CORP	Jul - Dec 2010 (Marcellus Only, 6 months)
BLACK	1H	259979.4	179	**1452.399**	CABOT OIL & GAS CORP	Jan - Jun 2011 (Marcellus Only, 6 months)

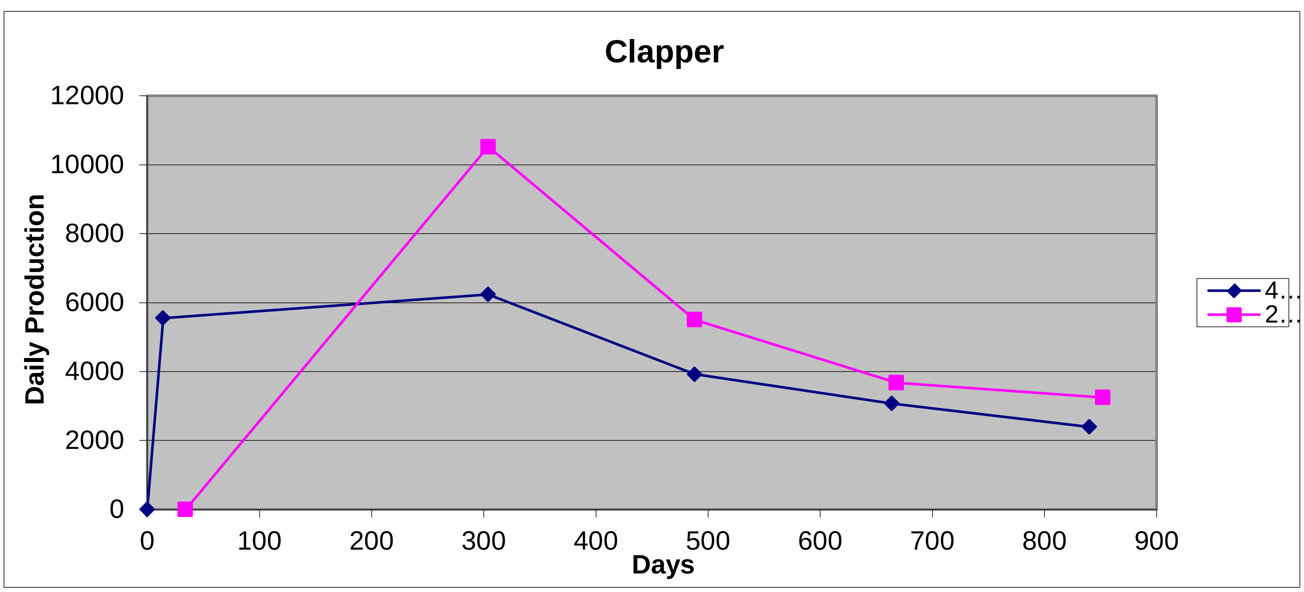
Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
BLACK	2H	817147	315	**2594.117**	CABOT OIL & GAS CORP	Jan - Dec 2009 (Annual O&G, with Marcellus)
		*132 days before second reporting period				
BLACK	2H	500537	365	**1371.334**	CABOT OIL & GAS CORP	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
BLACK	2H	200541	184	**1089.897**	CABOT OIL & GAS CORP	Jul - Dec 2010 (Marcellus Only, 6 months)
BLACK	2H	133597	181	**738.105**	CABOT OIL & GAS CORP	Jan - Jun 2011 (Marcellus Only, 6 months)



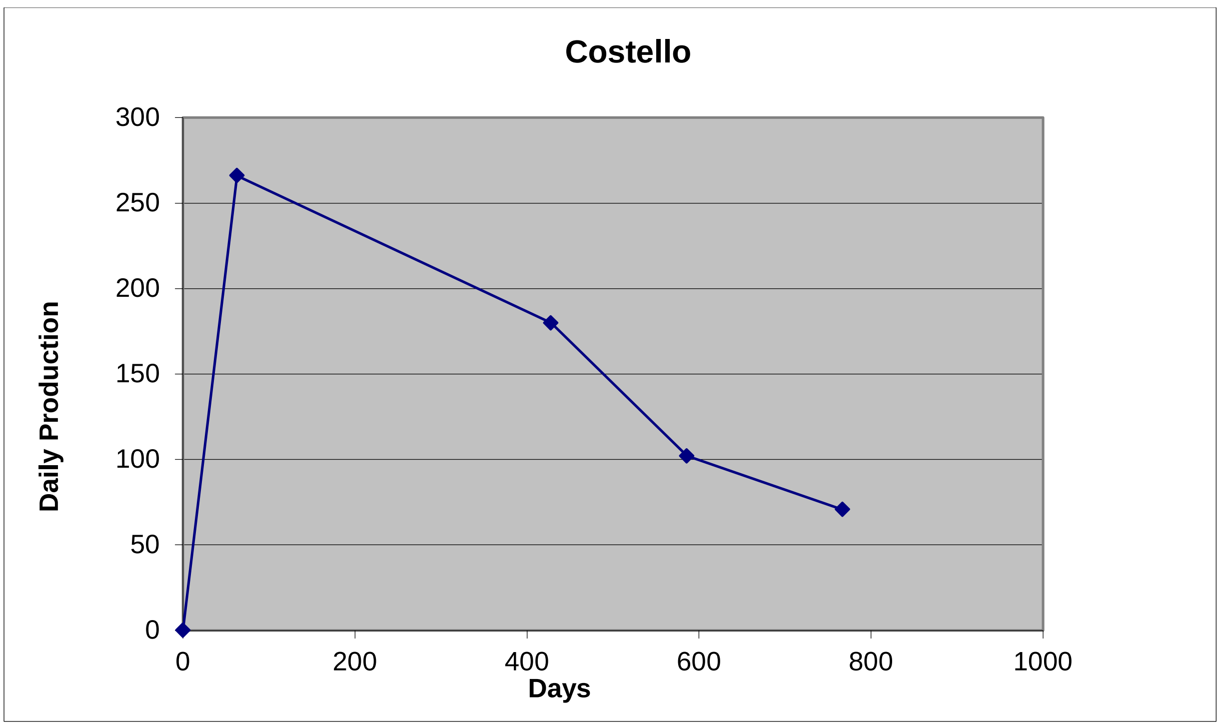
Farm Name	Well #	Gas Quantity	Gas Production	Gas per day	Operator Name	Reporting Period

		(Mcf)	**Days**			
CLAPPER	4H	677583	122	**5553.959**	CHESAPEAKE APPALACHIA LLC	Jan - Dec 2009 (Annual O&G, with Marcellus)
		**14 days of this production and then add numbers				
CLAPPER	4H	1809317	290	**6239.024**	CHESAPEAKE APPALACHIA LLC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
CLAPPER	4H	721608	184	**3921.783**	CHESAPEAKE APPALACHIA LLC	Jul - Dec 2010 (Marcellus Only, 6 months)
CLAPPER	4H	540968	176	**3073.682**	CHESAPEAKE APPALACHIA LLC	Jan - Jun 2011 (Marcellus Only, 6 months)
CLAPPER	4H	421897	176	**2397.142**	CHESAPEAKE APPALACHIA LLC	Jul - Dec 2011 (Marcellus Only, 6 months)

Farm Name	**Well #**	**Gas Quantity (Mcf)**	**Gas Production Days**	**Gas per day**	**Operator Name**	**Reporting Period**	
CLAPPER	2H	2841152	270	**10522.79**	N	CHESAPEAKE APPALACHIA LLC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
CLAPPER	2H	1012973	184	**5505.288**	N	CHESAPEAKE APPALACHIA LLC	Jul - Dec 2010 (Marcellus Only, 6 months)
CLAPPER	2H	662351	180	**3679.728**	N	CHESAPEAKE APPALACHIA LLC	Jan - Jun 2011 (Marcellus Only, 6 months)
CLAPPER	2H	597825	184	**3249.049**	N	CHESAPEAKE APPALACHIA LLC	Jul - Dec 2011 (Marcellus Only, 6 months)



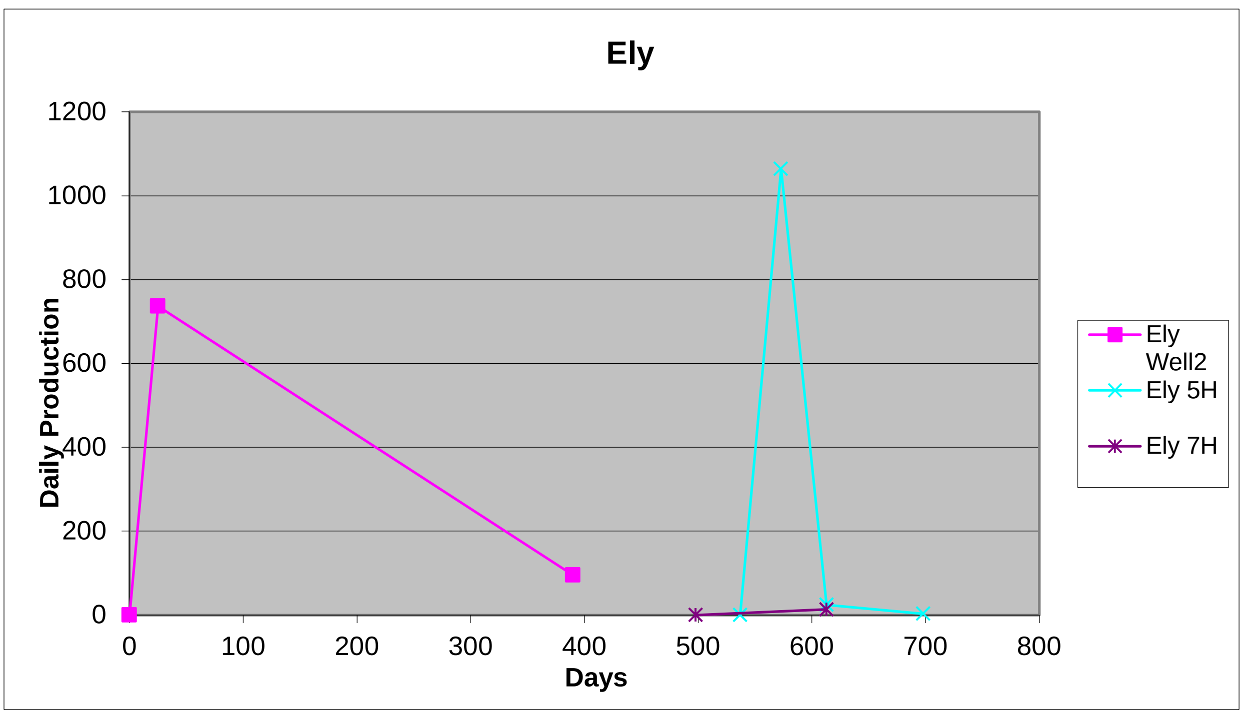
Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period	
COSTELLO		65460	246	**266.0976**	N	CABOT OIL & GAS CORP	Jan - Dec 2009 (Annual O&G, with Marcellus)
				Jan-Jul: 63 days then add numbers			
COSTELLO	2	65670	365	**179.9178**	N	CABOT OIL & GAS CORP	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
COSTELLO	2	16124	158	**102.0506**	N	CABOT OIL & GAS CORP	Jul - Dec 2010 (Marcellus Only, 6 months)
COSTELLO	2	12799	181	**70.71271**	N	CABOT OIL & GAS CORP	Jan - Jun 2011 (Marcellus Only, 6 months)



Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
ELY	Well 2	18420	25	**736.8**	CABOT OIL & GAS CORP	Jan - Dec 2008 (Annual O&G, with Marcellus)
ELY	Well 2	34762.5	365	**95.24**	CABOT OIL & GAS CORP	Jan - Dec 2009 (Annual O&G, with Marcellus)

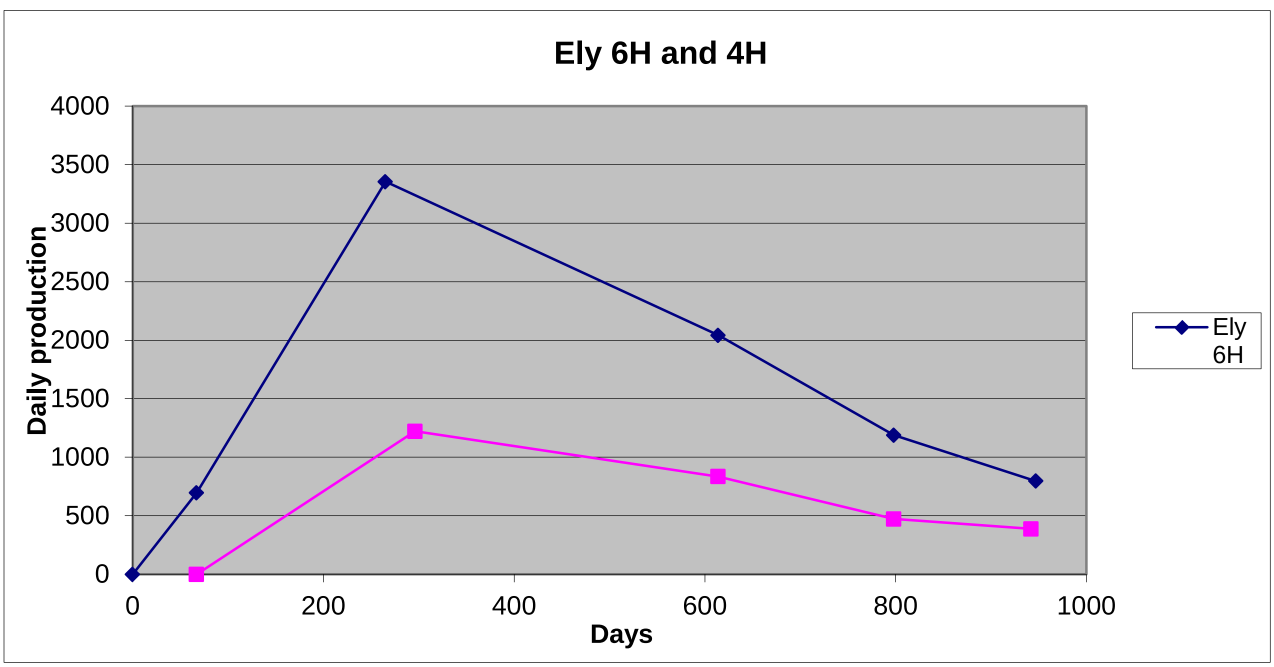
Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
ELY	5H	38317	36	**1064**	CABOT OIL & GAS CORP	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
ELY	5H	966	40	**24.15**	CABOT OIL & GAS CORP	Jul - Dec 2010 (Marcellus Only, 6 months)
ELY	5H	256	85	**3.012**	CABOT OIL & GAS CORP	Jan - Jun 2011 (Marcellus Only, 6 months)

Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
ELY	7H-SE	1519	115	**13.21**	CABOT OIL & GAS CORP	Jul - Dec 2010 (Marcellus Only, 6 months)

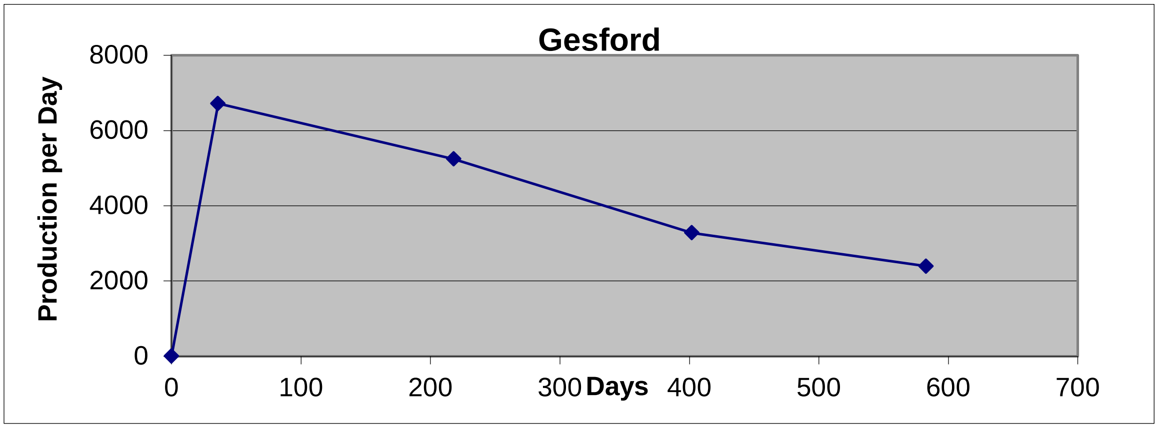


Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
ELY	6H	46678	67	**696.7**	CABOT OIL & GAS CORP	Jan - Dec 2008 (Annual O&G, with Marcellus)
ELY	6H	1224063	365	**3354**	CABOT OIL & GAS CORP	Jan - Dec 2009 (Annual O&G, with Marcellus)
			*** use 198 days at this production and add numbers from here			
ELY	6H	712697	349	**2042**	CABOT OIL & GAS CORP	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
ELY	6H	218668	184	**1188**	CABOT OIL & GAS CORP	Jul - Dec 2010 (Marcellus Only, 6 months)
ELY	6H	118622	149	**796.1**	CABOT OIL & GAS CORP	Jan - Jun 2011 (Marcellus Only, 6 months)

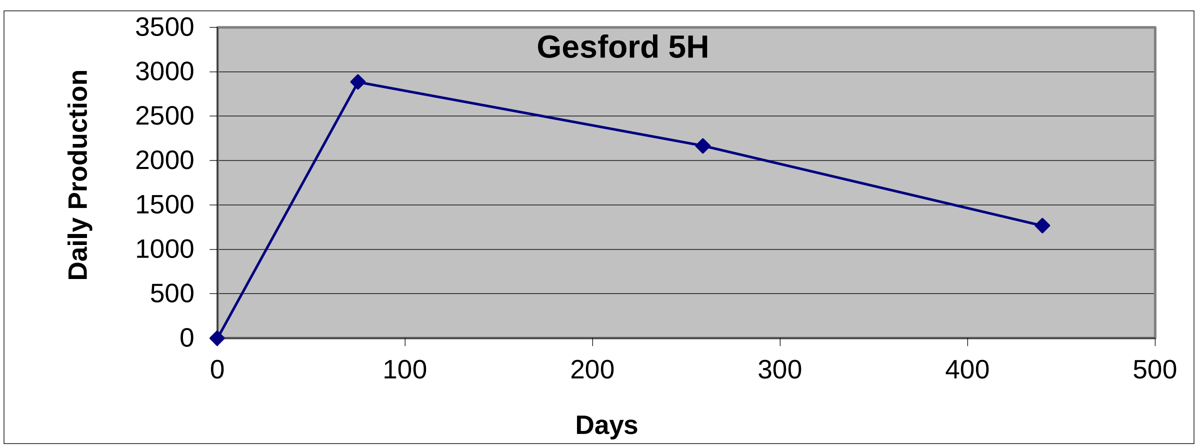
Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
ELY	4H	446068.9	365	**1222**	CABOT OIL & GAS CORP	Jan - Dec 2009 (Annual O&G, with Marcellus)
			***use 229 days at this production and add numbers from here			
ELY	4H	265476	318	**834.8**	CABOT OIL & GAS CORP	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
ELY	4H	87027	184	**473**	CABOT OIL & GAS CORP	Jul - Dec 2010 (Marcellus Only, 6 months)
ELY	4H	55722	144	**387**	CABOT OIL & GAS CORP	Jan - Jun 2011 (Marcellus Only, 6 months)



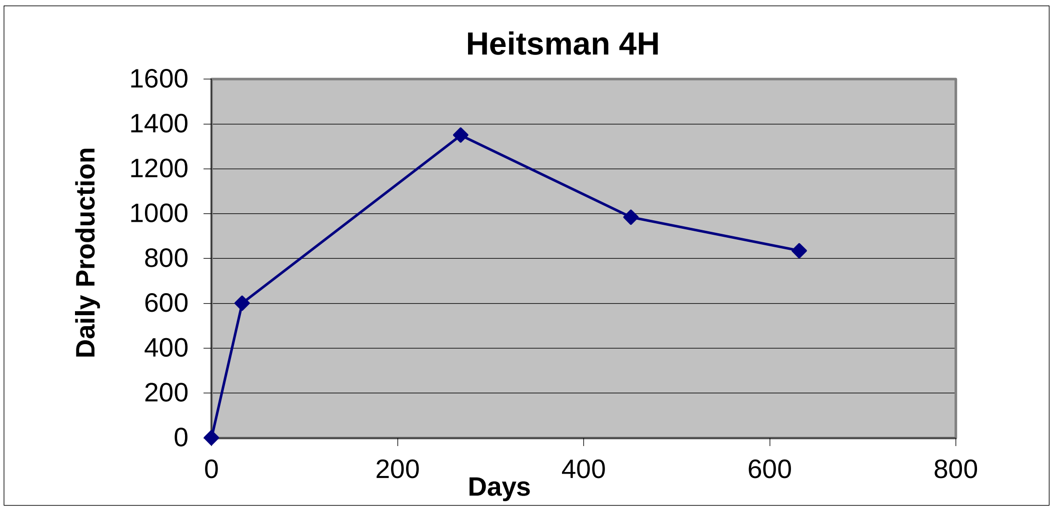
Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
GESFORD	7H	241712	36	**6714.222**	CABOT OIL & GAS CORP	Jan - Dec 2009 (Annual O&G, with Marcellus)
GESFORD	7H-NW	1142881	218	**5242.573**	CABOT OIL & GAS CORP	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
GESFORD	7H-NW	603889	184	**3282.005**	CABOT OIL & GAS CORP	Jul - Dec 2010 (Marcellus Only, 6 months)
GESFORD	7H-NW	433029.9	181	**2392.43**	CABOT OIL & GAS CORP	Jan - Jun 2011 (Marcellus Only, 6 months)



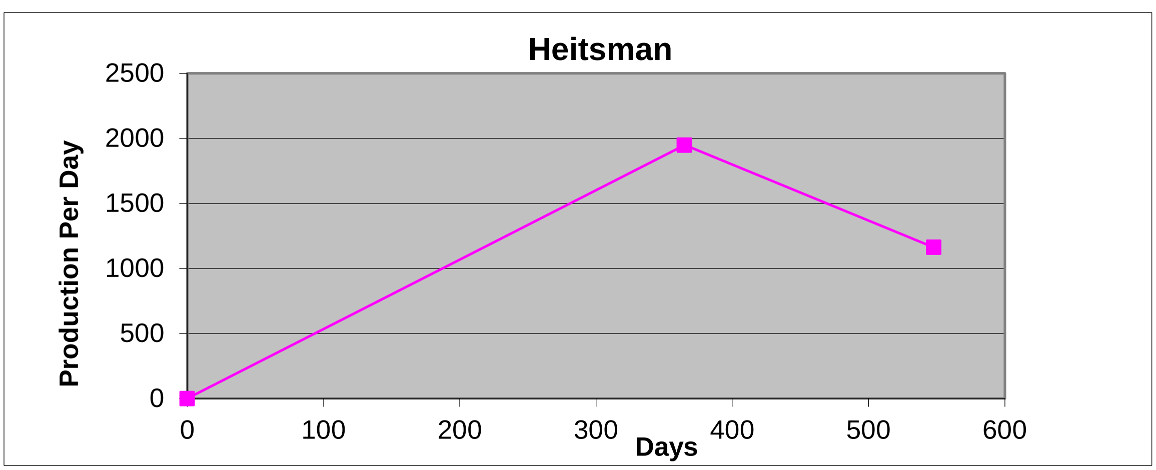
Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
GESFORD	5-H NW	216263	75	**2883.507**	CABOT OIL & GAS CORP	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
GESFORD	5H-NW	398353	184	**2164.962**	CABOT OIL & GAS CORP	Jul - Dec 2010 (Marcellus Only, 6 months)
GESFORD	5H-NW	229192.8	181	**1266.259**	CABOT OIL & GAS CORP	Jan - Jun 2011 (Marcellus Only, 6 months)



Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
HEITSMAN	4H	51652	86	**600.6047**	CABOT OIL & GAS CORP	Jan - Dec 2009 (Annual O&G, with Marcellus)
		***33 days at this production and then add numbers				
HEITSMAN	4H-NW	317288	235	**1350.162**	CABOT OIL & GAS CORP	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
HEITSMAN	4H-NW	180153	183	**984.4426**	CABOT OIL & GAS CORP	Jul - Dec 2010 (Marcellus Only, 6 months)
HEITSMAN	4H-NW	150998	181	**834.2431**	CABOT OIL & GAS CORP	Jan - Jun 2011 (Marcellus Only, 6 months)

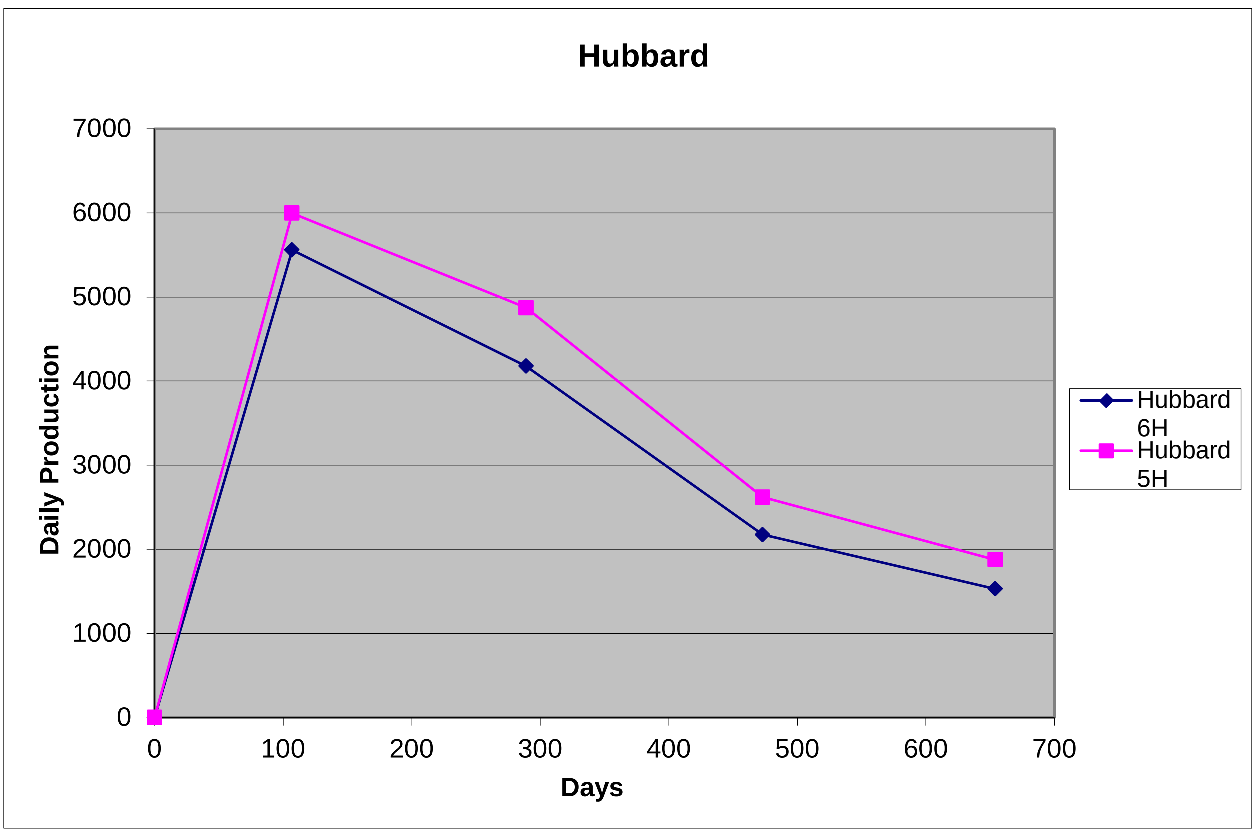


Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
HEITSMAN	1H	711068	365	**1948.132**	CABOT OIL & GAS CORP	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
HEITSMAN	1H	212843	183	**1163.077**	CABOT OIL & GAS CORP	Jul - Dec 2010 (Marcellus Only, 6 months)



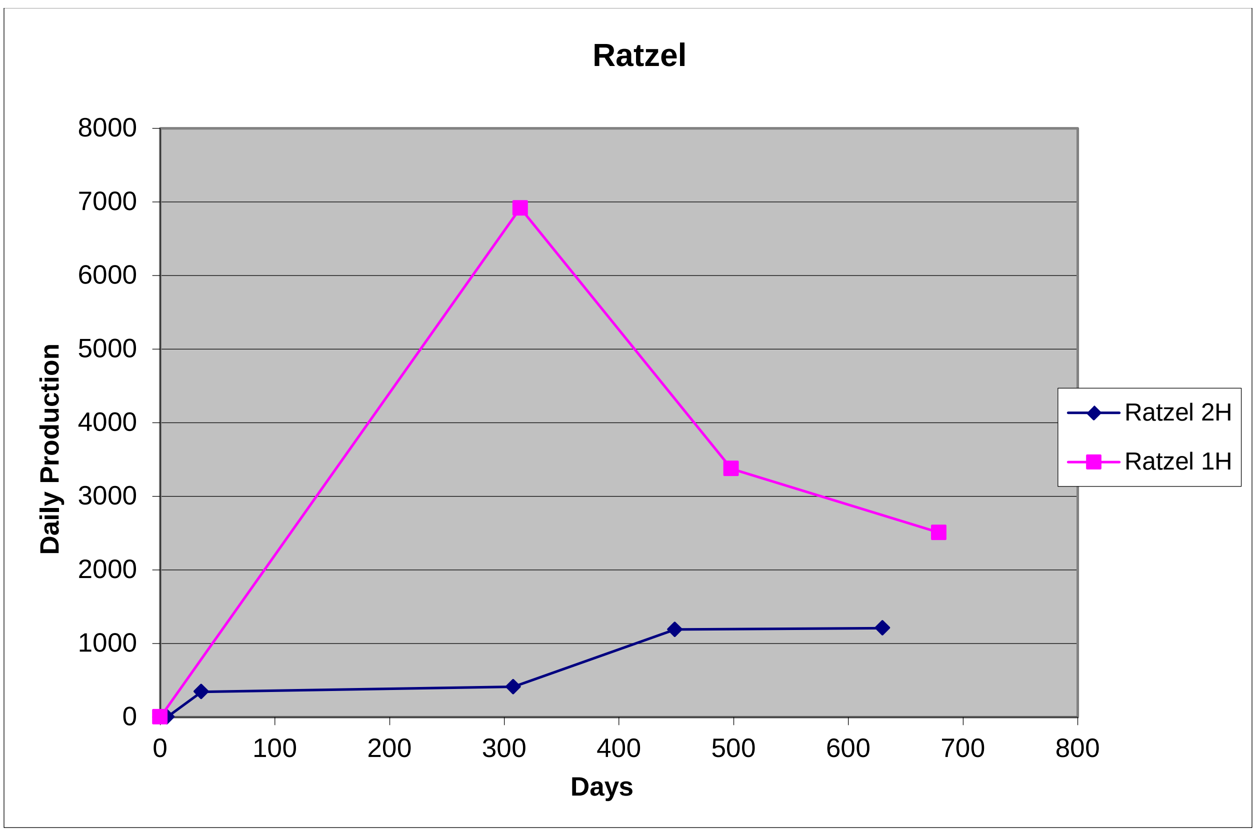
Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
HUBBARD	6H	594756	107	**5558.467**	CABOT OIL & GAS CORP	Jan - Dec 2009 (Annual O&G, with Marcellus)
HUBBARD	6H	1207135	289	**4176.938**	CABOT OIL & GAS CORP	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
HUBBARD	6H	400248	184	**2175.261**	CABOT OIL & GAS CORP	Jul - Dec 2010 (Marcellus Only, 6 months)
HUBBARD	6H	276866	181	**1529.646**	CABOT OIL & GAS CORP	Jan - Jun 2011 (Marcellus Only, 6 months)

HUBBARD	5H	641651	107	**5996.738**	CABOT OIL & GAS CORP	Jan - Dec 2009 (Annual O&G, with Marcellus)
HUBBARD	5H	1408136	289	**4872.443**	CABOT OIL & GAS CORP	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
HUBBARD	5H	482177	184	**2620.527**	CABOT OIL & GAS CORP	Jul - Dec 2010 (Marcellus Only, 6 months)
HUBBARD	5H	339603.9	181	**1876.264**	CABOT OIL & GAS CORP	Jan - Jun 2011 (Marcellus Only, 6 months)



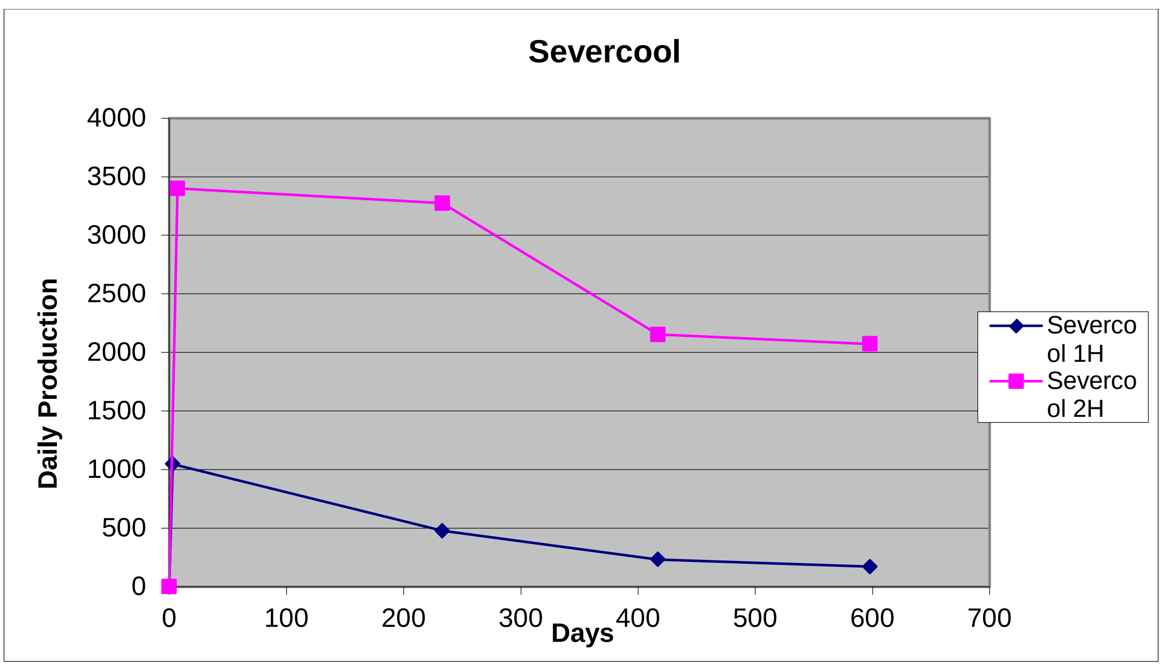
Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
RATZEL	2H	43418	126	**344.5873**	CABOT OIL & GAS CORP	Jan - Dec 2009 (Annual O&G, with Marcellus)
***use 36 days as total with this production then add days						
RATZEL	2H	111812	272	**411.0735**	CABOT OIL & GAS CORP	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
RATZEL	2H	167667	141	**1189.128**	CABOT OIL & GAS CORP	Jul - Dec 2010 (Marcellus Only, 6 months)
RATZEL	2H	218812	181	**1208.906**	CABOT OIL & GAS CORP	Jan - Jun 2011 (Marcellus Only, 6 months)

RATZEL	1H	2171399	314	**6915.283**	CABOT OIL & GAS CORP	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
RATZEL	1H	620923	184	**3374.582**	CABOT OIL & GAS CORP	Jul - Dec 2010 (Marcellus Only, 6 months)
RATZEL	1H	453894.5	181	**2507.704**	CABOT OIL & GAS CORP	Jan - Jun 2011 (Marcellus Only, 6 months)



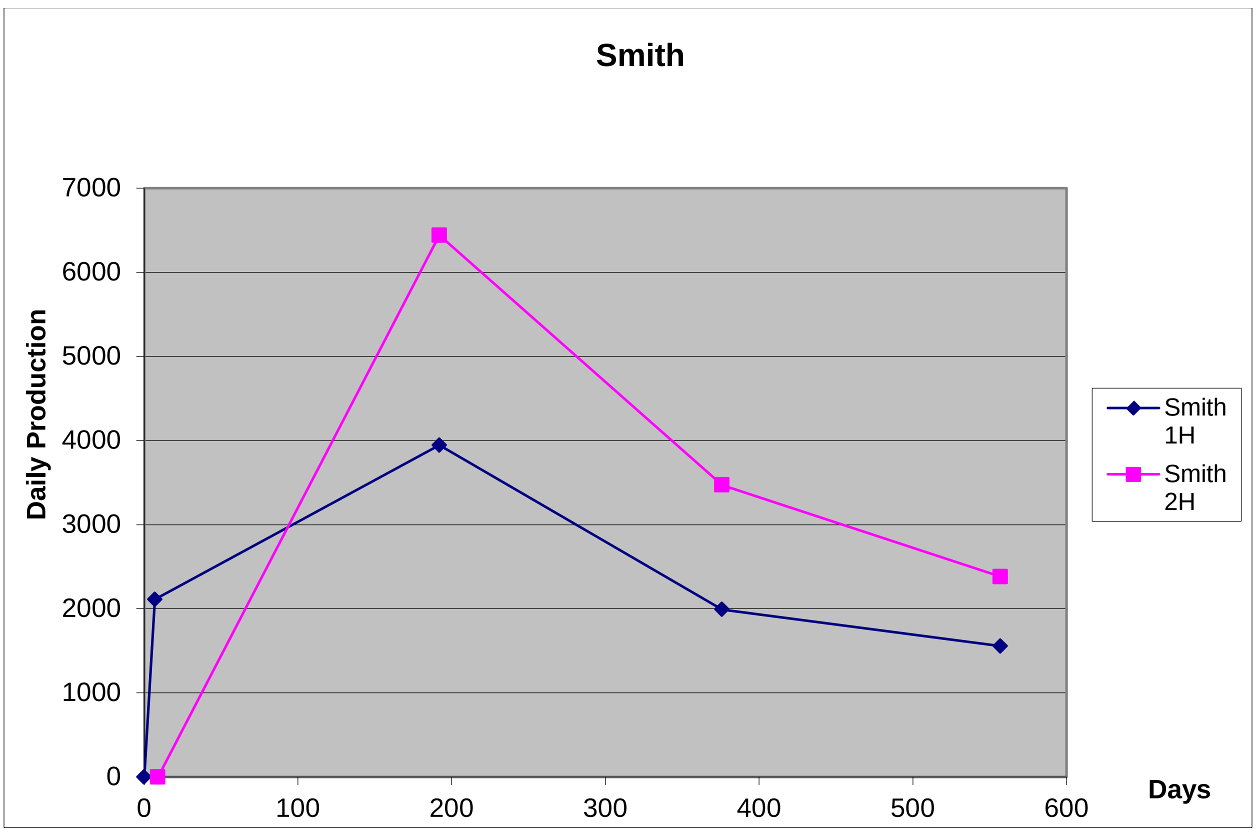
Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
SEVERCOOL	1	53406	51	**1047.176**	CABOT OIL & GAS CORP	Jan - Dec 2009 (Annual O&G, with Marcellus)
		***use this production for 3 days then add numbers				
SEVERCOOL	1	109570	230	**476.3913**	CABOT OIL & GAS CORP	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
SEVERCOOL	1	42759	184	**232.3859**	CABOT OIL & GAS CORP	Jul - Dec 2010 (Marcellus Only, 6 months)
SEVERCOOL	1	30813	181	**170.2376**	CABOT OIL & GAS CORP	Jan - Jun 2011 (Marcellus Only, 6 months)

SEVERCOOL	2	173370	51	**3399.412**	CABOT OIL & GAS CORP	Jan - Dec 2009 (Annual O&G, with Marcellus)
		**use this production for 7 days and then add numbers				
SEVERCOOL	2	739777	226	**3273.35**	CABOT	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
SEVERCOOL	2	396102	184	**2152.728**	CABOT	Jul - Dec 2010 (Marcellus Only, 6 months)
SEVERCOOL	2	375102.4	181	**2072.389**	CABOT	Jan - Jun 2011 (Marcellus Only, 6 months)

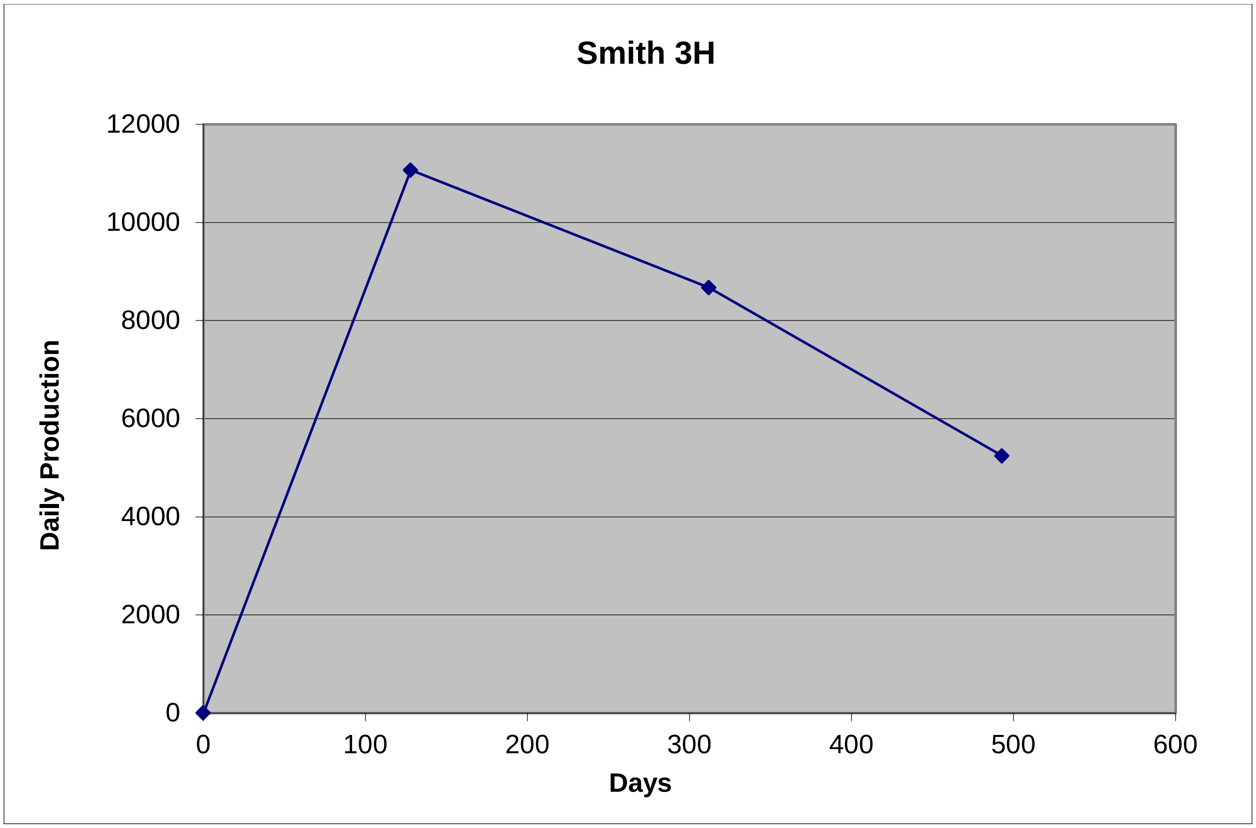


Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
SMITH	1H	21114	10	**2111.4**	CABOT OIL & GAS CORP	Jan - Dec 2009 (Annual O&G, with Marcellus)
		**use this production for 7 days and then add numbers				
SMITH	1H	729715	185	**3944.405**	CABOT OIL & GAS CORP	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
SMITH	1H	366251	184	**1990.495**	CABOT OIL & GAS CORP	Jul - Dec 2010 (Marcellus Only, 6 months)
SMITH	1H	281651.6	181	**1556.086**	CABOT OIL & GAS CORP	Jan - Jun 2011 (Marcellus Only, 6 months)

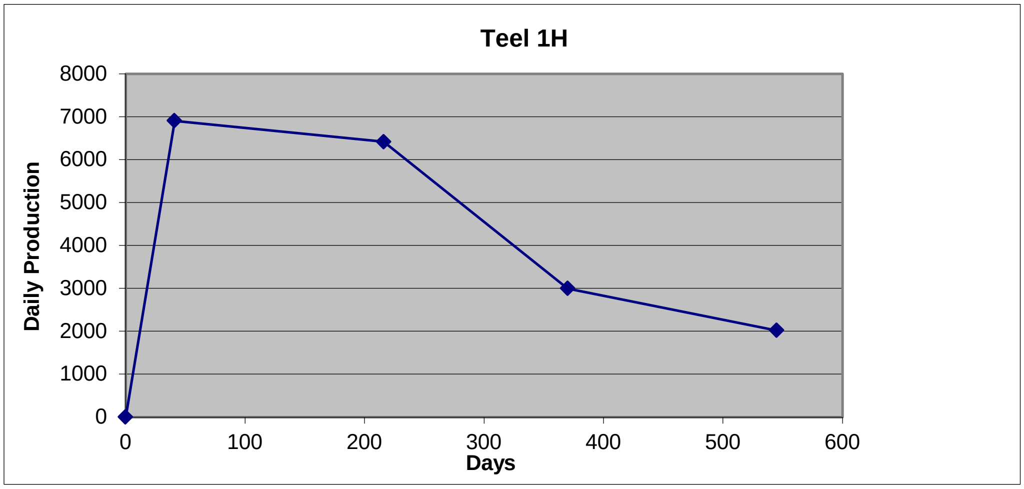
SMITH	2H	1178736	183	**6441.18**	CABOT OIL & GAS CORP	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
SMITH	2H	638606	184	**3470.685**	CABOT OIL & GAS CORP	Jul - Dec 2010 (Marcellus Only, 6 months)
SMITH	2H	431017.8	181	**2381.314**	CABOT OIL & GAS CORP	Jan - Jun 2011 (Marcellus Only, 6 months)



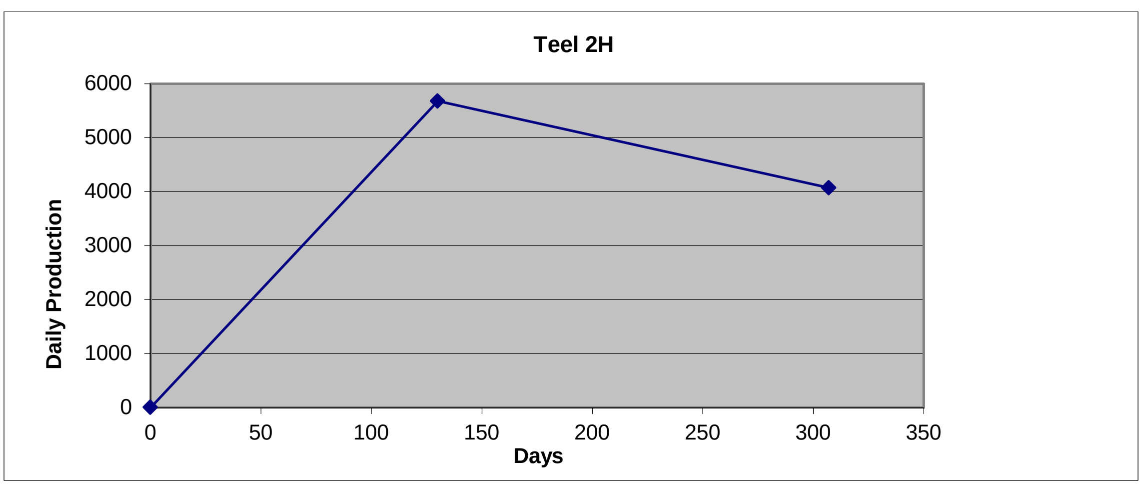
Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
SMITH	3H	1416281	128	**11064.7**	CABOT OIL & GAS CORP	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
SMITH	3H	1595385	184	**8670.571**	CABOT OIL & GAS CORP	Jul - Dec 2010 (Marcellus Only, 6 months)
SMITH	3H	948584.3	181	**5240.797**	CABOT OIL & GAS CORP	Jan - Jun 2011 (Marcellus Only, 6 months)



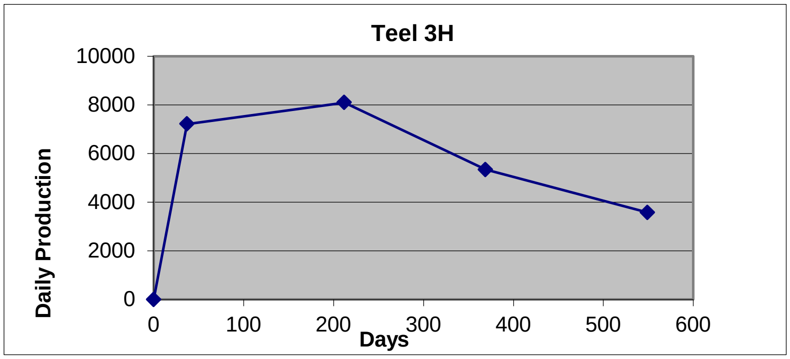
Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
TEEL	1H	283134	41	**6905.707**	CHIEF OIL & GAS LLC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
TEEL	1H	1122865	175	**6416.371**	CHIEF OIL & GAS LLC	Jul - Dec 2010 (Marcellus Only, 6 months)
TEEL	1H	461628	154	**2997.584**	CHIEF OIL & GAS LLC	Jan - Jun 2011 (Marcellus Only, 6 months)
TEEL	1H	353774	175	**2021.566**	CHIEF OIL & GAS LLC	Jul - Dec 2011 (Marcellus Only, 6 months)



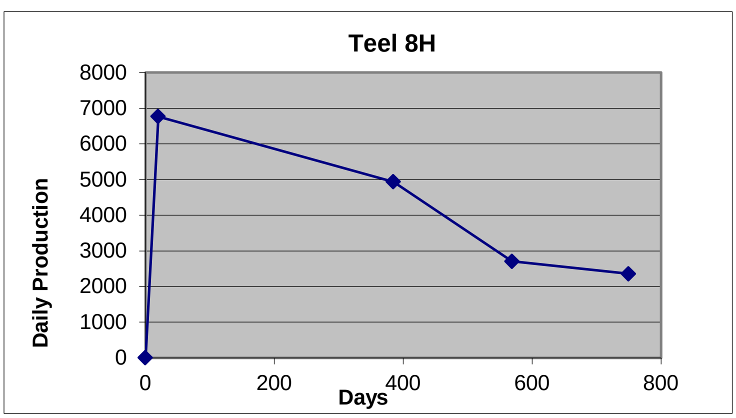
Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
TEEL	2H	738231	130	**5678.7**	CHIEF OIL & GAS LLC	Jan - Jun 2011 (Marcellus Only, 6 months)
TEEL	2H	720406	177	**4070.09**	CHIEF OIL & GAS LLC	Jul - Dec 2011 (Marcellus Only, 6 months)



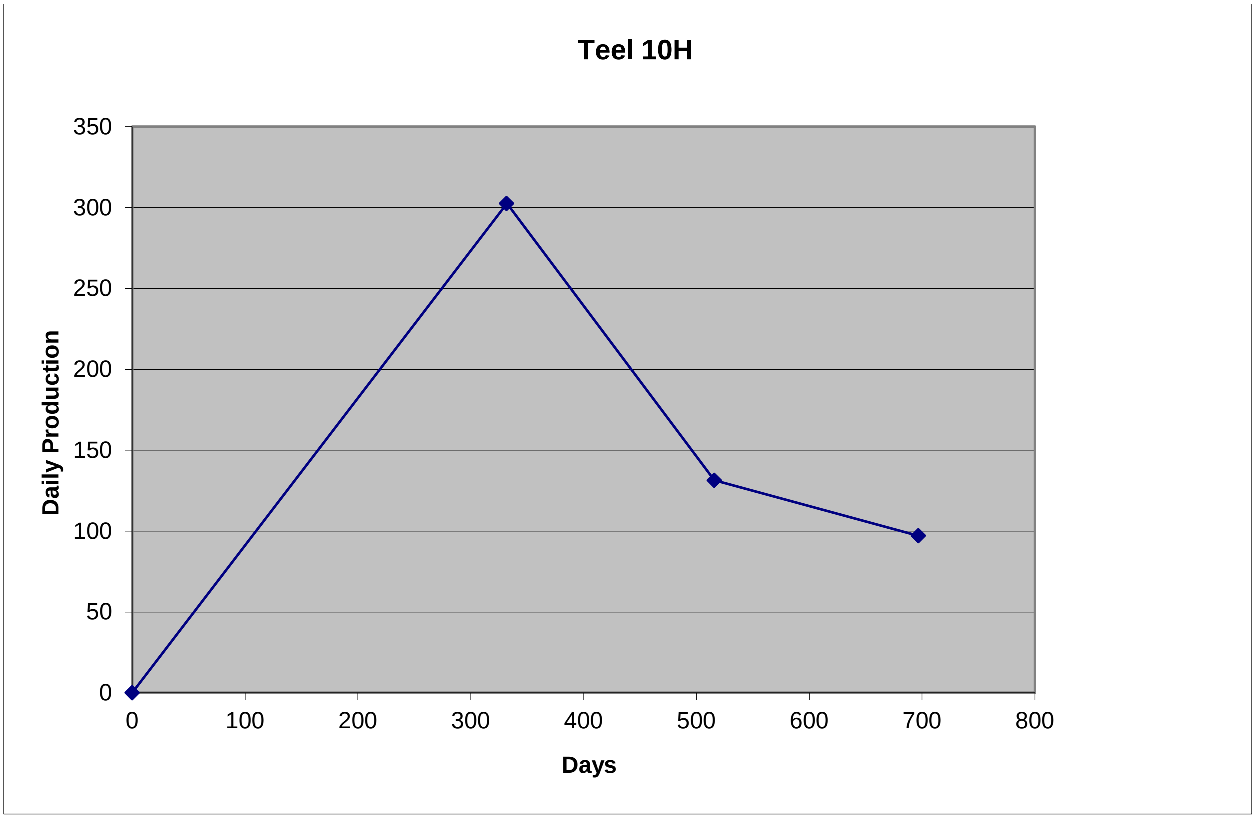
Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
TEEL	3H	266976	37	**7215.568**	CHIEF OIL & GAS LLC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
TEEL	3H	1417439	175	**8099.651**	CHIEF OIL & GAS LLC	Jul - Dec 2010 (Marcellus Only, 6 months)
TEEL	3H	839194	157	**5345.185**	CHIEF OIL & GAS LLC	Jan - Jun 2011 (Marcellus Only, 6 months)
TEEL	3H	644771	180	**3582.061**	CHIEF OIL & GAS LLC	Jul - Dec 2011 (Marcellus Only, 6 months)



Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
TEEL	8H	1374185	203	**6769.384**	CABOT OIL & GAS CORP	Jan - Dec 2009 (Annual O&G, with Marcellus)
			*20.5 days			
TEEL	8H	1802475	365	**4938.288**	CABOT OIL & GAS CORP	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
**production per day does not change if just consider Jan-June 2010 (182.5 days)						
TEEL	8H	498339	184	**2708.364**	CABOT OIL & GAS CORP	Jul - Dec 2010 (Marcellus Only, 6 months)
TEEL	8H	426240.5	181	**2354.92**	CABOT OIL & GAS CORP	Jan - Jun 2011 (Marcellus Only, 6 months)

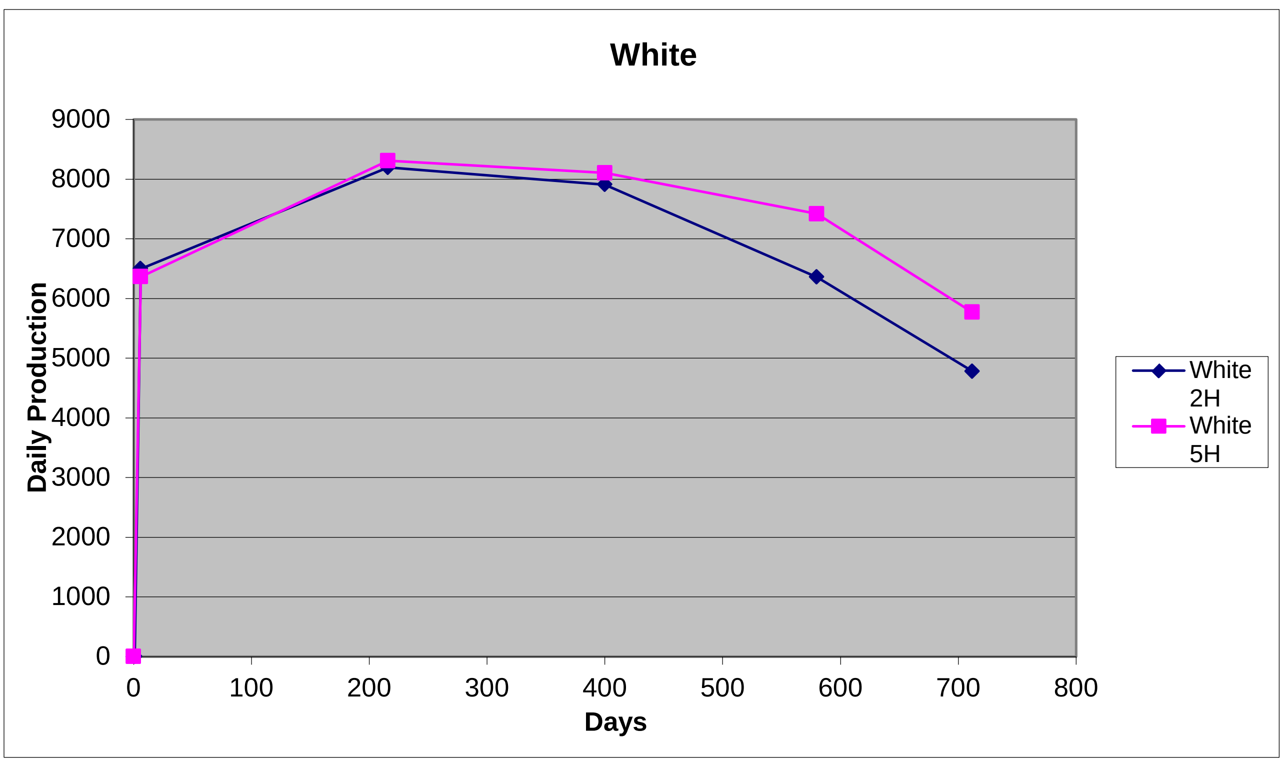


Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
TEEL	10H	100423	332	**302.4789**	CABOT OIL & GAS CORP	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
TEEL	10H	24185	184	**131.4402**	CABOT OIL & GAS CORP	Jul - Dec 2010 (Marcellus Only, 6 months)
TEEL	10H	17582	181	**97.13812**	CABOT OIL & GAS CORP	Jan - Jun 2011 (Marcellus Only, 6 months)



Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
WHITE	2H	214409	33	**6497.242**	CHESAPEAKE APPALACHIA LLC	Jan - Dec 2009 (Annual O&G, with Marcellus)
		***5 days of this production then add days				
WHITE	2h	1720584	210	**8193.257**	CHESAPEAKE APPALACHIA LLC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
WHITE	2H	1455089	184	**7908.092**	CHESAPEAKE APPALACHIA LLC	Jul - Dec 2010 (Marcellus Only, 6 months)
WHITE	2H	1144583	180	**6358.794**	CHESAPEAKE APPALACHIA LLC	Jan - Jun 2011 (Marcellus Only, 6 months)
WHITE	2H	630846	132	**4779.136**	CHESAPEAKE APPALACHIA LLC	Jul - Dec 2011 (Marcellus Only, 6 months)

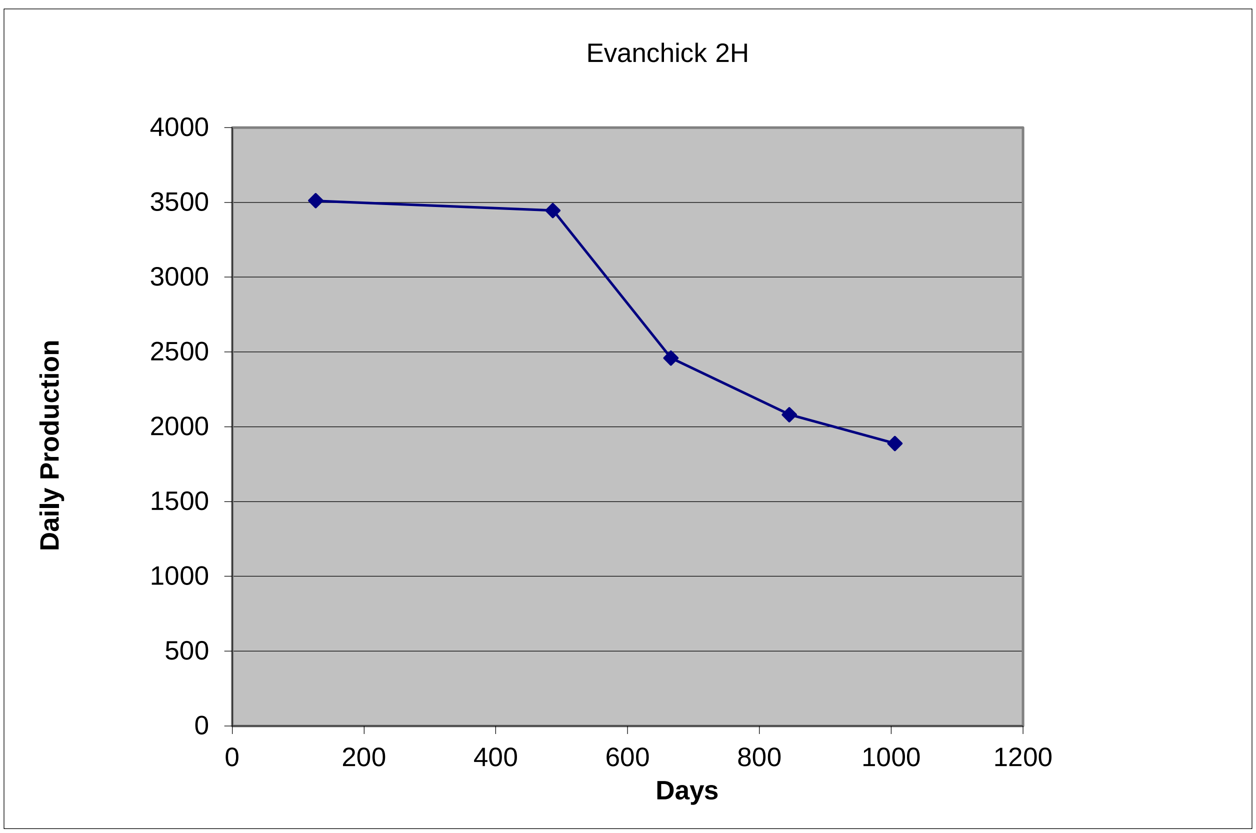
WHITE	5H	216384	34	**6364.235**	CHESAPEAKE APPALACHIA LLC	Jan - Dec 2009 (Annual O&G, with Marcellus)
		***6 days of this production then add days				
WHITE	5h	1744220	210	**8305.81**	CHESAPEAKE APPALACHIA LLC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
WHITE	5h	1491013	184	**8103.332**	CHESAPEAKE APPALACHIA LLC	Jul - Dec 2010 (Marcellus Only, 6 months)
WHITE	5h	1335284	180	**7418.244**	CHESAPEAKE APPALACHIA LLC	Jan - Jun 2011 (Marcellus Only, 6 months)
WHITE	5h	761501	132	**5768.947**	CHESAPEAKE APPALACHIA LLC	Jul - Dec 2011 (Marcellus Only, 6 months)



Bradford Wells

Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
OLSYN	1	19430	79	**245.9494**	EOG RESOURCES INC	Jan - Dec 2008 (Annual O&G, with Marcellus)
OLSYN	1	28809	232	**124.1767**	EOG RESOURCES INC	Jan - Dec 2009 (Annual O&G, with Marcellus)
				**use this production for 49 days and then add days		
OLSYN	1	28624	149	**192.1074**	EOG RESOURCES INC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
OLSYN	1	39477	184	**214.5489**	EOG RESOURCES INC	Jul - Dec 2010 (Marcellus Only, 6 months)
OLSYN	1	26159	181	**144.5249**	EOG RESOURCES INC	Jan - Jun 2011 (Marcellus Only, 6 months)
OLSYN	1	32609	184	**177.2228**	EOG RESOURCES INC	Jul - Dec 2011 (Marcellus Only, 6 months)

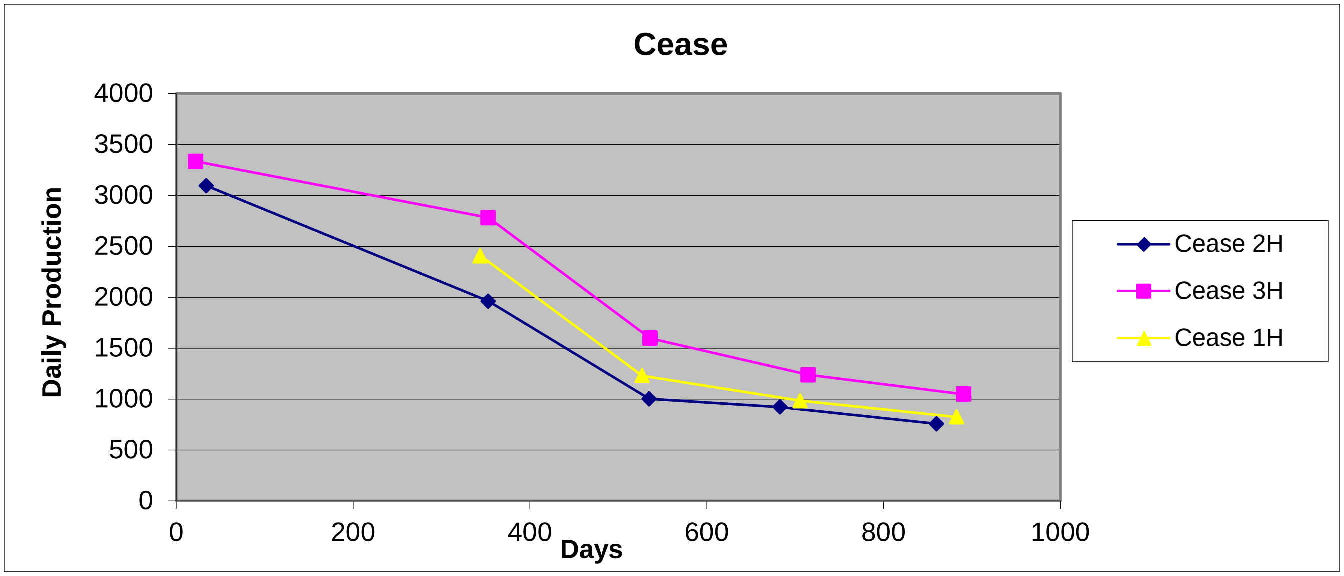
Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
EVANCHICK	2H	4092.6	31	132.0194	COLUMBIA NATURAL RES INC	Jan - Dec 2008 (Annual O&G, with Marcellus)
EVANCHICK	2H	979434	279	3510.516	CHESAPEAKE APPALACHIA LLC	Jan - Dec 2009 (Annual O&G, with Marcellus)
			**use 96 days at this production then add days			
EVANCHICK	2H	1240156	360	3444.878	CHESAPEAKE APPALACHIA LLC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
EVANCHICK	2H	440138	179	2458.872	CHESAPEAKE APPALACHIA LLC	Jul - Dec 2010 (Marcellus Only, 6 months)
EVANCHICK	2H	374560	180	2080.889	CHESAPEAKE APPALACHIA LLC	Jan - Jun 2011 (Marcellus Only, 6 months)
EVANCHICK	2H	302039	160	1887.744	CHESAPEAKE APPALACHIA LLC	Jul - Dec 2011 (Marcellus Only, 6 months)



Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
CEASE	3H	536838	161	**3334.398**	TALISMAN ENERGY USA INC	Jan - Dec 2009 (Annual O&G, with Marcellus)
		**13 days at this production then add days				
CEASE	3H	920305.3	331	**2780.379**	TALISMAN ENERGY USA INC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
CEASE	3H	292401.8	183	**1597.824**	TALISMAN ENERGY USA INC	Jul - Dec 2010 (Marcellus Only, 6 months)
CEASE	3H	221525	179	**1237.57**	TALISMAN ENERGY USA INC	Jan - Jun 2011 (Marcellus Only, 6 months)
CEASE	3H	184333	176	**1047.347**	TALISMAN ENERGY USA INC	Jul - Dec 2011 (Marcellus Only, 6 months)

Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
CEASE	1H	746318.6	310	**2407.479**	TALISMAN ENERGY USA INC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
CEASE	1H	224938.8	183	**1229.174**	TALISMAN ENERGY USA INC	Jul - Dec 2010 (Marcellus Only, 6 months)
CEASE	1H	176061	179	**983.581**	TALISMAN ENERGY USA INC	Jan - Jun 2011 (Marcellus Only, 6 months)
CEASE	1H	145777	177	**823.5989**	TALISMAN ENERGY USA INC	Jul - Dec 2011 (Marcellus Only, 6 months)

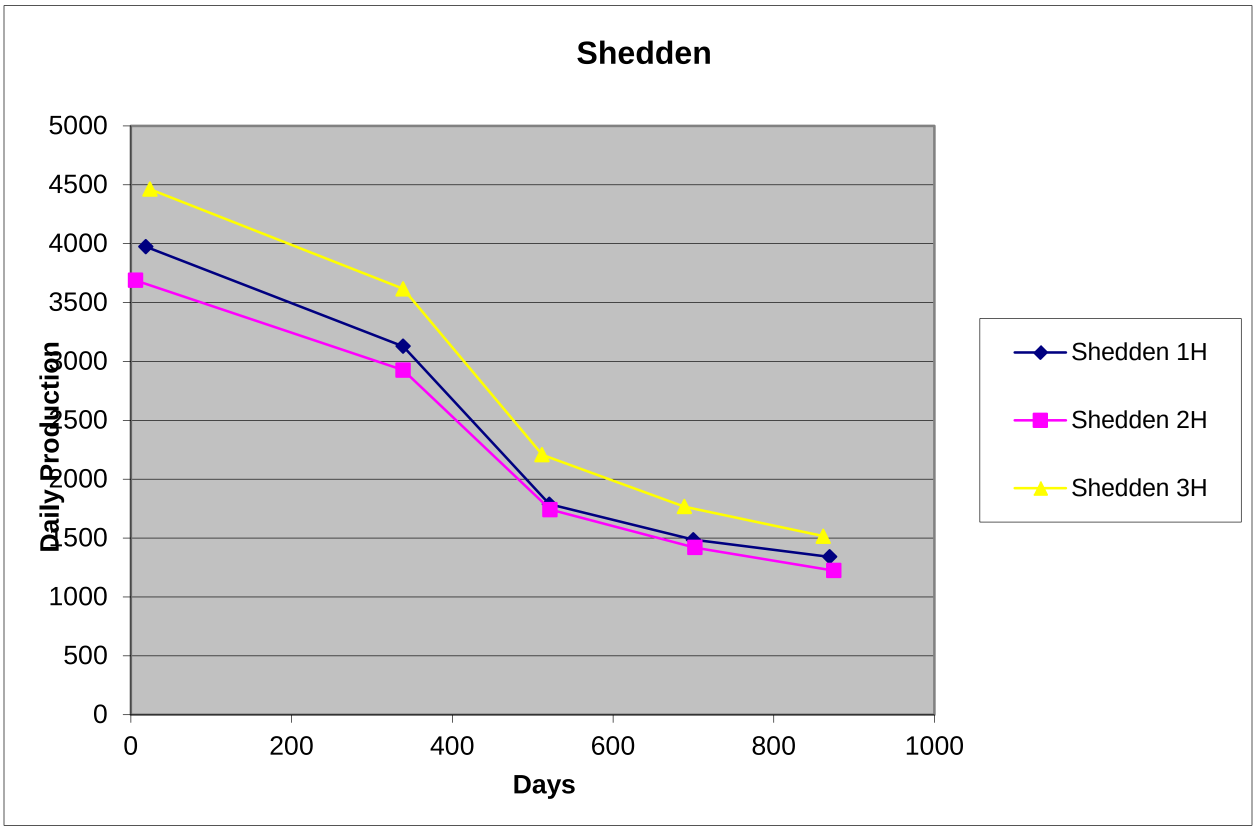
CEASE	2H	526251	170	**3095.594**	TALISMAN ENERGY USA INC	Jan - Dec 2009 (Annual O&G, with Marcellus)
		**34 days at this production then add numbers				
CEASE	2H	625210.8	319	**1959.908**	TALISMAN ENERGY USA INC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
CEASE	2H	182280.5	182	**1001.541**	TALISMAN ENERGY USA INC	Jul - Dec 2010 (Marcellus Only, 6 months)
CEASE	2H	136356	148	**921.3243**	TALISMAN ENERGY USA INC	Jan - Jun 2011 (Marcellus Only, 6 months)
CEASE	2H	133832	177	**756.113**	TALISMAN ENERGY USA INC	Jul - Dec 2011 (Marcellus Only, 6 months)



Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
SHEDDEN	1H	588033	148	**3973.196**	TALISMAN ENERGY USA INC	Jan - Dec 2009 (Annual O&G, with Marcellus)
		**11 days of production and add numbers				
SHEDDEN	1H	1000915	320	**3127.86**	TALISMAN ENERGY USA INC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
SHEDDEN	1H	325232.6	182	**1786.992**	TALISMAN ENERGY USA INC	Jul - Dec 2010 (Marcellus Only, 6 months)
SHEDDEN	1H	265802	179	**1484.927**	TALISMAN ENERGY USA INC	Jan - Jun 2011 (Marcellus Only, 6 months)
SHEDDEN	1H	227705	170	**1339.441**	TALISMAN ENERGY USA INC	Jul - Dec 2011 (Marcellus Only, 6 months)

SHEDDEN	2H	575335	156	**3688.045**	TALISMAN ENERGY USA INC	Jan - Dec 2009 (Annual O&G, with Marcellus)
			**6 days at this production and add numbers			
SHEDDEN	2H	974166.8	333	**2925.426**	TALISMAN ENERGY USA INC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
SHEDDEN	2H	318509.2	183	**1740.487**	TALISMAN ENERGY USA INC	Jul - Dec 2010 (Marcellus Only, 6 months)
SHEDDEN	2H	255267	180	**1418.15**	TALISMAN ENERGY USA INC	Jan - Jun 2011 (Marcellus Only, 6 months)
SHEDDEN	2H	211502	173	**1222.555**	TALISMAN ENERGY USA INC	Jul - Dec 2011 (Marcellus Only, 6 months)

SHEDDEN	3H	669471	150	**4463.14**	TALISMAN ENERGY USA INC	Jan - Dec 2009 (Annual O&G, with Marcellus)
		**18 days at this production and add numbers				
SHEDDEN	3H	1139214	315	**3616.553**	TALISMAN ENERGY USA INC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
SHEDDEN	3H	381753.9	173	**2206.67**	TALISMAN ENERGY USA INC	Jul - Dec 2010 (Marcellus Only, 6 months)
SHEDDEN	3H	312739	177	**1766.887**	TALISMAN ENERGY USA INC	Jan - Jun 2011 (Marcellus Only, 6 months)
SHEDDEN	3H	262190	173	**1515.549**	TALISMAN ENERGY USA INC	Jul - Dec 2011 (Marcellus Only, 6 months)



Farm Name	**Well #**	**Gas Quantity (Mcf)**	**Gas Production Days**	**Gas per day**	**Operator Name**	**Reporting Period**
SHEDDEN	8H	443269.7	155	**2859.805**	TALISMAN ENERGY USA INC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
SHEDDEN	8H	400700.3	183	**2189.619**	TALISMAN ENERGY USA INC	Jul - Dec 2010 (Marcellus Only, 6 months)
SHEDDEN	8H	316720	180	**1759.556**	TALISMAN ENERGY USA INC	Jan - Jun 2011 (Marcellus Only, 6 months)

SHEDDEN	8H	267146	184	**1451.88**	TALISMAN ENERGY USA INC	Jul - Dec 2011 (Marcellus Only, 6 months)

Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
SHEDDEN	7H	376979.6	156	**2416.536**	TALISMAN ENERGY USA INC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
SHEDDEN	7H	316691.9	183	**1730.557**	TALISMAN ENERGY USA INC	Jul - Dec 2010 (Marcellus Only, 6 months)
SHEDDEN	7H	242637	180	**1347.983**	TALISMAN ENERGY USA INC	Jan - Jun 2011 (Marcellus Only, 6 months)
SHEDDEN	7H	208355	184	**1132.364**	TALISMAN ENERGY USA INC	Jul - Dec 2011 (Marcellus Only, 6 months)

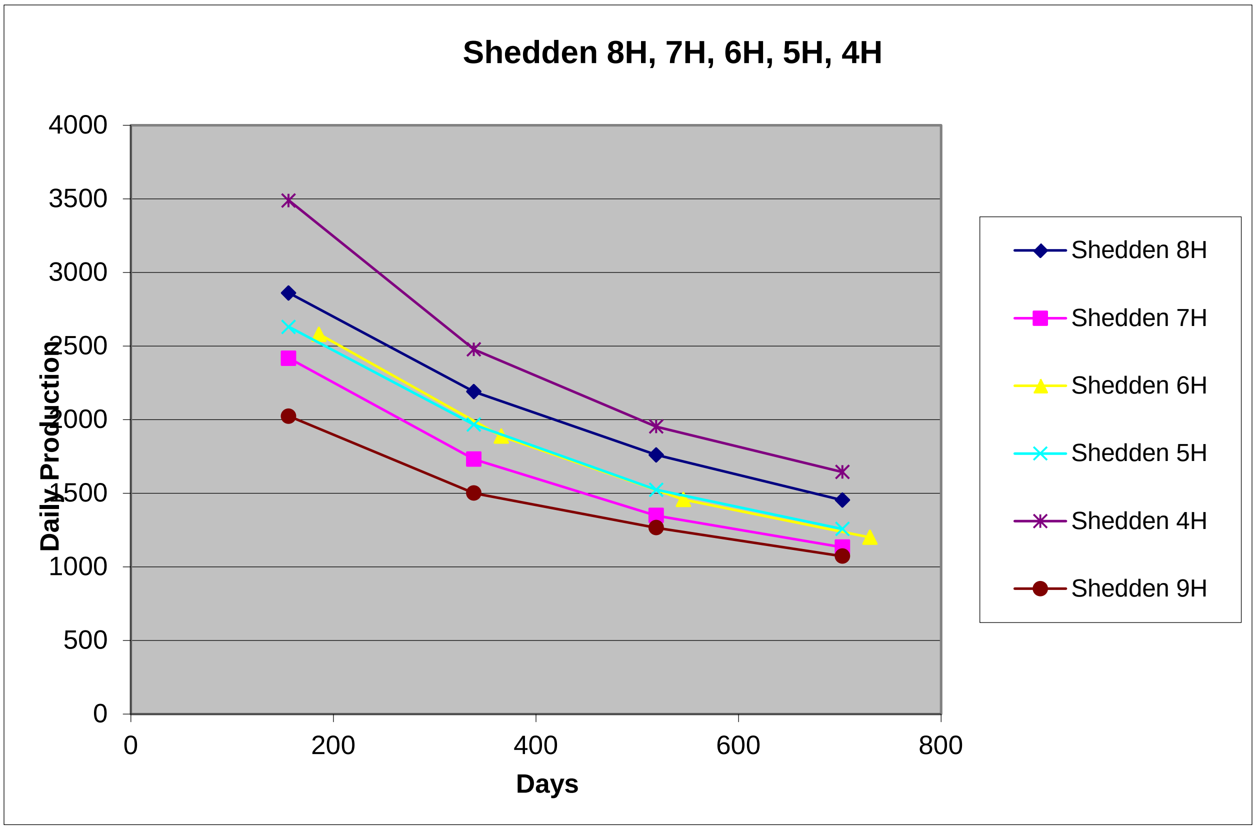
SHEDDEN	6H	394659.8	153	**2579.476**	TALISMAN ENERGY USA INC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
SHEDDEN	6H	345430	183	**1887.596**	TALISMAN ENERGY USA INC	Jul - Dec 2010 (Marcellus Only, 6 months)
SHEDDEN	6H	262207	180	**1456.706**	TALISMAN ENERGY USA INC	Jan - Jun 2011 (Marcellus Only, 6 months)
SHEDDEN	6H	220863	184	**1200.342**	TALISMAN ENERGY USA INC	Jul - Dec 2011 (Marcellus Only, 6 months)

SHEDDEN	5H	397155.6	151	**2630.17**	TALISMAN ENERGY USA INC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
SHEDDEN	5H	359711.4	183	**1965.636**	TALISMAN ENERGY USA INC	Jul - Dec 2010 (Marcellus Only, 6 months)
SHEDDEN	5H	274126	180	**1522.922**	TALISMAN ENERGY USA INC	Jan - Jun 2011 (Marcellus Only, 6 months)
SHEDDEN	5H	231255	184	**1256.821**	TALISMAN ENERGY USA INC	Jul - Dec 2011 (Marcellus Only, 6 months)

SHEDDEN	4H	530226	152	**3488.329**	TALISMAN ENERGY USA INC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
SHEDDEN	4H	453102	183	**2475.967**	TALISMAN ENERGY USA INC	Jul - Dec 2010 (Marcellus Only, 6 months)
SHEDDEN	4H	351357	180	**1951.983**	TALISMAN ENERGY USA INC	Jan - Jun 2011 (Marcellus Only, 6 months)
SHEDDEN	4H	302343	184	**1643.168**	TALISMAN ENERGY USA INC	Jul - Dec 2011 (Marcellus Only, 6 months)

SHEDDEN	9H	309470.1	153	**2022.68**	TALISMAN ENERGY USA INC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)

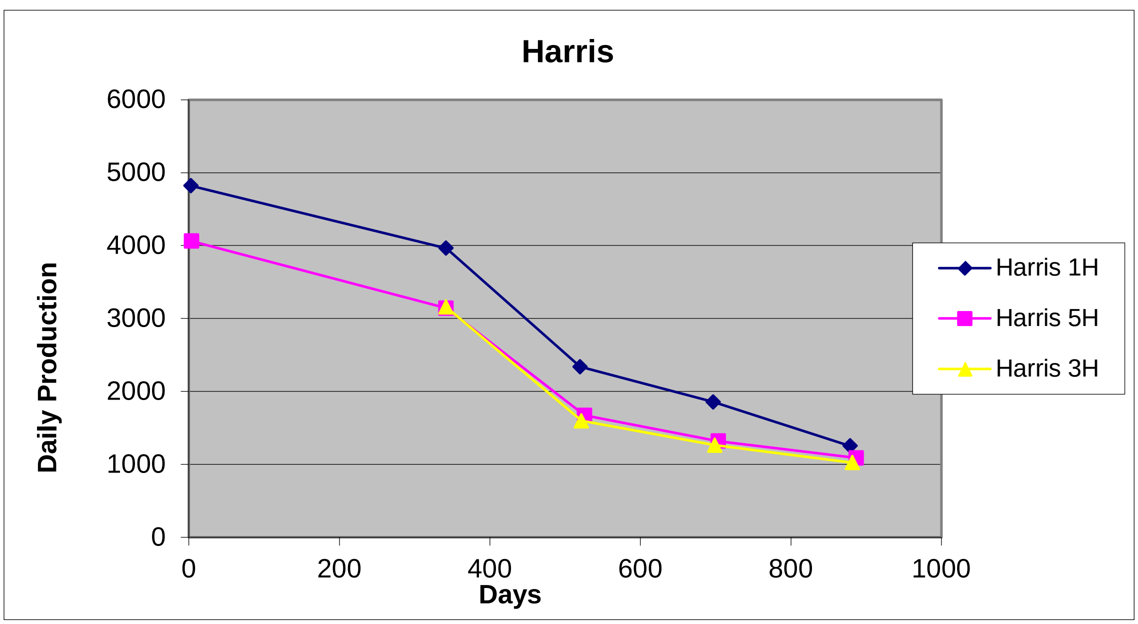
SHEDDEN	9H	274478.7	183	**1499.884**	TALISMAN ENERGY USA INC	Jul - Dec 2010 (Marcellus Only, 6 months)
SHEDDEN	9H	227842	180	**1265.789**	TALISMAN ENERGY USA INC	Jan - Jun 2011 (Marcellus Only, 6 months)
SHEDDEN	9H	197263	184	**1072.082**	TALISMAN ENERGY USA INC	Jul - Dec 2011 (Marcellus Only, 6 months)



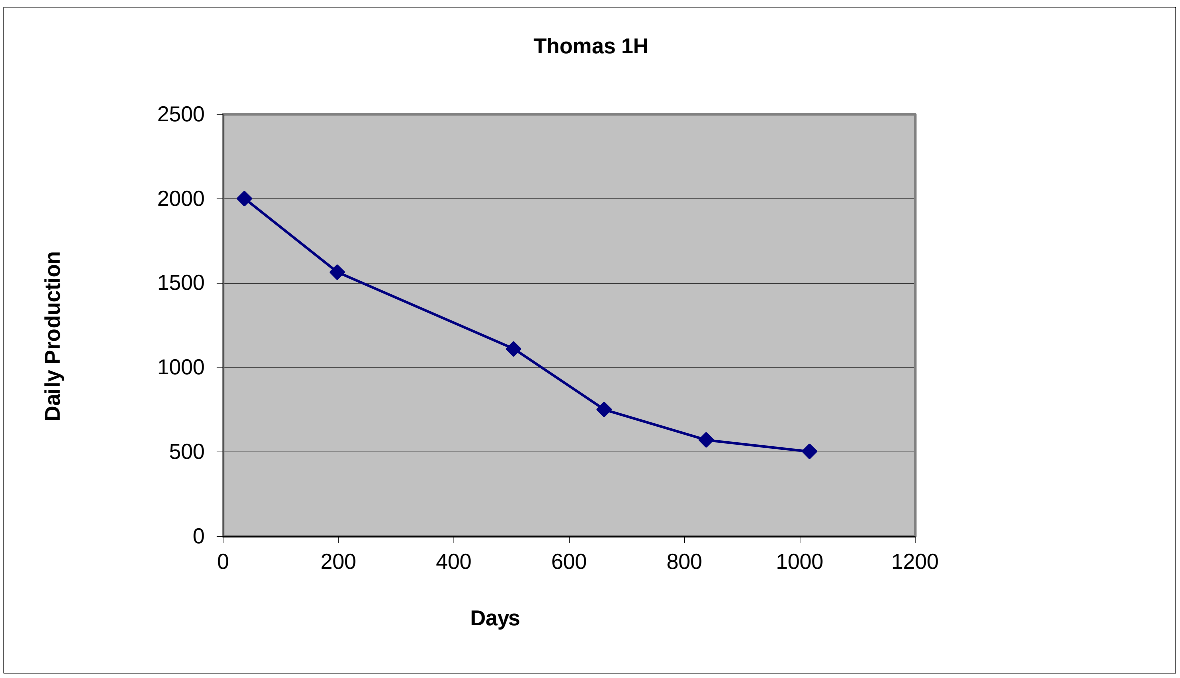
Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
HARRIS	1H	771030	160	4818.938	TALISMAN ENERGY USA INC	Jan - Dec 2009 (Annual O&G, with Marcellus)
			***3 days at this production then add days			
HARRIS	1H	1343573	339	3963.341	TALISMAN ENERGY USA INC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
HARRIS	1H	416469.4	178	2339.716	TALISMAN ENERGY USA INC	Jul - Dec 2010 (Marcellus Only, 6 months)
HARRIS	1H	328347	177	1855.068	TALISMAN ENERGY USA INC	Jan - Jun 2011 (Marcellus Only, 6 months)
HARRIS	1H	227899	182	1252.192	TALISMAN	Jan-Jun 2011

HARRIS	5H	649660	160	4060.375	TALISMAN ENERGY USA INC	Jan - Dec 2009 (Annual O&G, with Marcellus)
			***4 days at this production then add days			
HARRIS	5H	1062041	338	3142.134	TALISMAN ENERGY USA INC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
HARRIS	5H	307794.4	184	1672.796	TALISMAN ENERGY USA INC	Jul - Dec 2010 (Marcellus Only, 6 months)
HARRIS	5H	234599	178	1317.972	TALISMAN ENERGY USA INC	Jan - Jun 2011 (Marcellus Only, 6 months)
HARRIS	5H	199197	183	1088.508	TALISMAN ENERGY USA INC	Jul - Dec 2011 (Marcellus Only, 6 months)

HARRIS	3H	1076088	341	3155.683	TALISMAN ENERGY USA INC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
HARRIS	3H	287603.4	180	1597.797	TALISMAN ENERGY USA INC	Jul - Dec 2010 (Marcellus Only, 6 months)
HARRIS	3H	223571	177	1263.113	TALISMAN ENERGY USA INC	Jan - Jun 2011 (Marcellus Only, 6 months)
HARRIS	3H	187677	183	1025.557	TALISMAN ENERGY USA INC	Jul - Dec 2011 (Marcellus Only, 6 months)

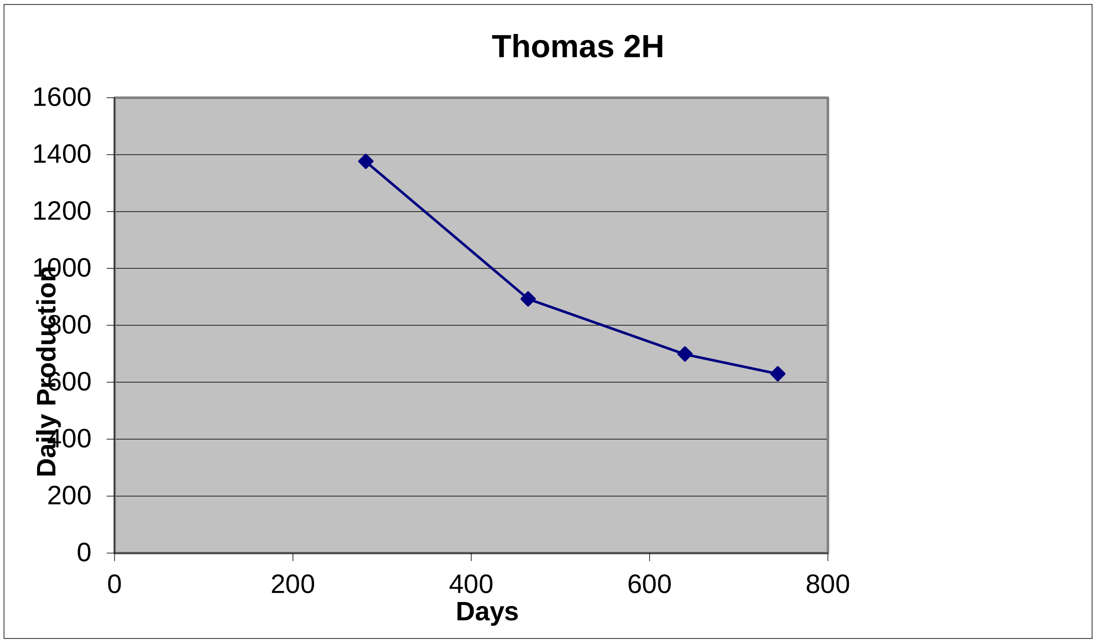


Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
THOMAS	1H	74079	37	2002.1	TALISMAN ENERGY USA INC	Jan - Dec 2008 (Annual O&G, with Marcellus)
THOMAS	1H	446345	285	1566.1	TALISMAN ENERGY USA INC	Jan - Dec 2009 (Annual O&G, with Marcellus)
			***161 days at this production level			
THOMAS	1H	339883.2	306	1110.7	TALISMAN ENERGY USA INC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
THOMAS	1H	117998.7	157	751.58	TALISMAN ENERGY USA INC	Jul - Dec 2010 (Marcellus Only, 6 months)
THOMAS	1H	101178	177	571.63	TALISMAN ENERGY USA INC	Jan - Jun 2011 (Marcellus Only, 6 months)
THOMAS	1H	90008	179	502.84	TALISMAN ENERGY USA INC	Jul - Dec 2011 (Marcellus Only, 6 months)



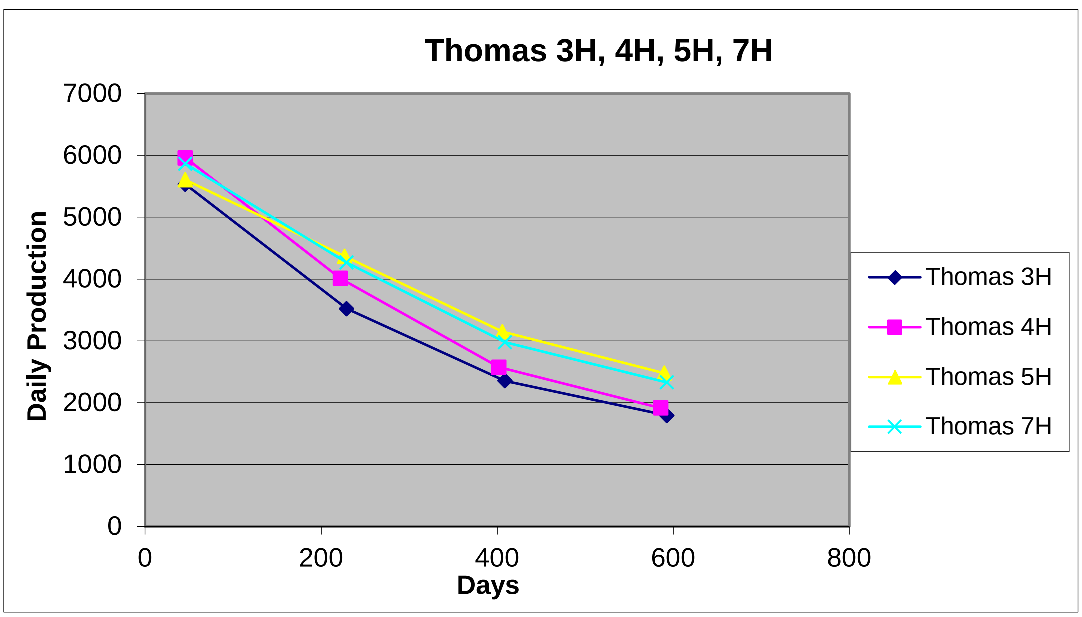
Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
THOMAS	2H	387772.6	282	1375.1	TALISMAN ENERGY USA INC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
THOMAS	2H	162394.7	182	892.28	TALISMAN ENERGY USA INC	Jul - Dec 2010 (Marcellus Only, 6 months)

THOMAS	2H	122914	176	698.38	TALISMAN ENERGY USA INC	Jan - Jun 2011 (Marcellus Only, 6 months)
THOMAS	2H	65412	104	628.96	TALISMAN ENERGY USA INC	Jul - Dec 2011 (Marcellus Only, 6 months)



Farm Name	Well #	Gas Quantity (Mcf)	Gas Production Days	Gas per day	Operator Name	Reporting Period
THOMAS	3H	254409.5	46	5530.6	TALISMAN ENERGY USA INC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
THOMAS	3H	644313.7	183	3520.8	TALISMAN ENERGY USA INC	Jul - Dec 2010 (Marcellus Only, 6 months)
THOMAS	3H	423651	180	2353.6	TALISMAN ENERGY USA INC	Jan - Jun 2011 (Marcellus Only, 6 months)
THOMAS	3H	329830	184	1792.6	TALISMAN ENERGY USA INC	Jul - Dec 2011 (Marcellus Only, 6 months)
THOMAS	4H	274012.6	46	5956.8	TALISMAN ENERGY USA INC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
THOMAS	4H	705790.8	176	4010.2	TALISMAN ENERGY USA INC	Jul - Dec 2010 (Marcellus Only, 6 months)
THOMAS	4H	463114	180	2572.9	TALISMAN ENERGY USA INC	Jan - Jun 2011 (Marcellus Only, 6 months)

THOMAS	4H	351879	184	1912.4	TALISMAN ENERGY USA INC	Jul - Dec 2011 (Marcellus Only, 6 months)
THOMAS	5H	257745.2	46	5603.2	TALISMAN ENERGY USA INC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
THOMAS	5H	790335.2	181	4366.5	TALISMAN ENERGY USA INC	Jul - Dec 2010 (Marcellus Only, 6 months)
THOMAS	5H	563457	179	3147.8	TALISMAN ENERGY USA INC	Jan - Jun 2011 (Marcellus Only, 6 months)
THOMAS	5H	455803	184	2477.2	TALISMAN ENERGY USA INC	Jul - Dec 2011 (Marcellus Only, 6 months)
THOMAS	7H	269620	46	5861.3	TALISMAN ENERGY USA INC	Jul 2009 - Jun 2010 (Marcellus Only, 12 months)
THOMAS	7H	781255.2	183	4269.2	TALISMAN ENERGY USA INC	Jul - Dec 2010 (Marcellus Only, 6 months)
THOMAS	7H	535765	180	2976.5	TALISMAN ENERGY USA INC	Jan - Jun 2011 (Marcellus Only, 6 months)
THOMAS	7H	428313	184	2327.8	TALISMAN ENERGY USA INC	Jul - Dec 2011 (Marcellus Only, 6 months)



XIII. Appendix E: Decay Exponents of Wells

Pad	Number Wells	Well ID	Slope	Exponent	R^2
1 Well per pad					
Costello	1	1H	328.3575	-0.00191	0.940
Smith	1	3H	15,021.74	-0.00205	0.95947
Gesford	1	5H	3562.1	-0.0023	0.9686
Gesford	1	7H	7467.1	-0.002	0.9878
Heitsman	1	1H	5449.7	-0.0028	1
Heitsman	1	4H	1878.5	-0.0013	0.9696
Smith	1	3H	15021.74	-0.00205	0.95947
Teel	1	1H	8802.6	-0.0027	0.9124
Teel	1	2H	7252.4	-0.0019	1
Teel	1	3H	13349	-0.0024	0.9975
Teel	1	8H	7413.4	-0.0015	0.9255
Teel	1	10H	781.1	-0.0031	0.9344
Olsyn	1	1H	187.89	-0.0001	0.0228
Evanchick	1	2H	4228.7	-0.0008	0.8719
Thomas	1	1H	2121.4	-0.0015	0.9854
Thomas	1	2H	2103	-0.0017	0.9697
2 Wells per pad					
Black	2	1H	5,947.98	-0.00165	0.999
Black	2	2H	3,244.50	-0.00168	0.995
Clapper	2	4H	17,813.17	-0.00215	0.918
Clapper	2	2H	17,813	-0.0022	0.918
Smith	2	1H	10,463.51	-0.00273	0.982
Smith	2	2H	5,996.02	-0.00255	0.93364
Hubbard	2	5H	8156.448	-0.00225	0.96813
Hubbard	2	6H	7620.282	-0.00248	0.9784
Ratzel	2	1H	15475	-0.0028	0.9479
Severcool	2	1H	1003.2	-0.0031	0.9811
Severcool	2	2H	3589.7	-0.001	0.8455
Smith	2	1H	5996.019	-0.00255	0.93364
Smith	2	2H	10463.51	-0.00273	0.982
White	2	2H	11112	-0.0011	0.8715
White	2	5H	10142	-0.0007	0.7821

3 Wells per pad					
Cease	3	1H	4054.2	-0.0019	0.8996
Cease	3	2H	3264.7	-0.0018	0.9487
Cease	3	3H	3755.7	-0.0015	0.9373
Shedden	3	1H	4241.5	-0.0014	0.9367
Shedden	3	2H	3930	-0.0014	0.949
Shedden	3	3H	4898.4	-0.0014	0.9494
Harris	3	1H	5490	-0.0016	0.9416
Harris	3	3H	5448.7	-0.002	0.9088
Harris	3	5H	4395.7	-0.0016	0.944
4 Wells per pad					
Thomas	4	3H	5842.5	-0.0021	0.988
Thomas	4	4H	6444.7	-0.0021	0.9929
Thomas	4	5H	6043.1	-0.0015	0.9958
Thomas	4	7H	6281.7	-0.0017	0.9944
6 Wells per pad					
Shedden	6	4H	4131.7	-0.0014	0.9767
Shedden	6	5H	3175	-0.0014	0.9916
Shedden	6	6H	3251.9	-0.0014	0.9882
Shedden	6	7H	2881.3	-0.0014	0.9801
Shedden	6	8H	3400.7	-0.0012	0.9943
Shedden	6	9H	2322.7	-0.0011	0.9765

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