Impact Fee Update and 2015 Outlook

Introduction

Since 2012, Pennsylvania has collected an annual impact fee for unconventional (i.e., shale) natural gas wells that were drilled or operating in the previous calendar year. This research brief analyzes calendar year (CY) 2014 impact fee revenues (remitted April 2015) reported by the Pennsylvania Public Utility Commission (PUC) and potential scenarios for CY 2015. The research brief also translates the impact fee into an annual average effective tax rate (ETR) based on natural gas price and production data. The ETR is a metric that quantifies the implicit tax burden imposed by the impact fee in a given year.

From CY 2011 to CY 2014, the impact fee has generated nearly $856 million in revenues, which are distributed to local governments and state agencies to offset the impact from unconventional natural gas extraction. (See Table 1.) The proceeds provide funds for infrastructure, emergency services, environmental initiatives and various other programs. By statute, the distributions to Commonwealth agencies occur before all others, and remain constant from year to year. The balance of funds are then distributed to local governments, the Marcellus Legacy Fund, and the Housing and Rehabilitation Enhancement Fund (HARE Fund). Counties and municipalities receive funds based on the prevalence of drilling activity in each jurisdiction or their proximity to jurisdictions in which drilling activity takes place.

2014 Impact Fee Revenues

The annual impact fee for an unconventional natural gas well is determined according to a bracketed schedule based on the number of years since a well became subject to the impact fee (operating year), the type of well (horizontal or vertical) and, to a limited extent, the annual average price of natural gas.[1] Table 2 on the following page displays the applicable fee schedule for CY 2011 to CY 2015 (estimate).

For CY 2014, the PUC reports the number of wells by operating year and type, and two characteristics motivate impact fee revenues for that year:

- A well's operating year is determined by its spud date, a point in time that represents the onset of drilling activity. For CY 2014, a well spud in 2014 is in its first operating year. If a well is plugged, it must still remit the applicable impact fee for that year.
- Wells that produce less than 90 Mcf (thousand cubic feet) of natural gas per day on average are known as "stripper wells." By statute, all horizontal wells must remit the impact fee for three years, regardless of production levels. Following that three-year period, horizontal wells that qualify as stripper wells are exempt from the impact fee. Wells that are spud but not completed or shut-in and do not produce are treated as stripper wells.[2] Vertical wells that qualify as stripper wells are exempt from the fee, regardless of operating year.

Table 1: Impact Fee Revenues and Distributions

	CY 2011	CY 2012	CY 2013	CY 2014
Total Revenues	$204,210	$202,472	$225,752	$223,500
Counties, Municipalities and HARE Fund[1]	108,726	107,683	123,151	123,300
Marcellus Legacy Fund	82,484	79,289	84,601	82,200
Commonwealth Agencies	10,500	10,500	10,500	10,500
County & State Conserv. Districts/Comm.[2]	2,500	5,000	7,500	7,500

Note: Dollar amounts in thousands. Remittances made in April of the following calendar year.
Source: Pennsylvania Public Utility Commission.
[1] Housing Affordability and Rehabilitation Enhancement Fund.
[2] The distribution to County Conservation Districts is set by statute to increase by increments of $2.5 million from CY 2011 to CY 2013, and thereafter to increase by the regional CPI-U as published by the U.S. Bureau of Labor Statistics.

Table 2: Impact Fee Schedule for Horizontal Wells[1]

Operating Year	CY 2011	CY 2012	CY 2013	CY 2014[2]	CY 2015[3]
1	$50,000	$45,000	$50,000	$50,300	$45,300
2	-	35,000	40,000	40,200	35,200
3	-	-	30,000	30,200	30,200
4	-	-	-	20,100	15,100
5	-	-	-	-	15,100

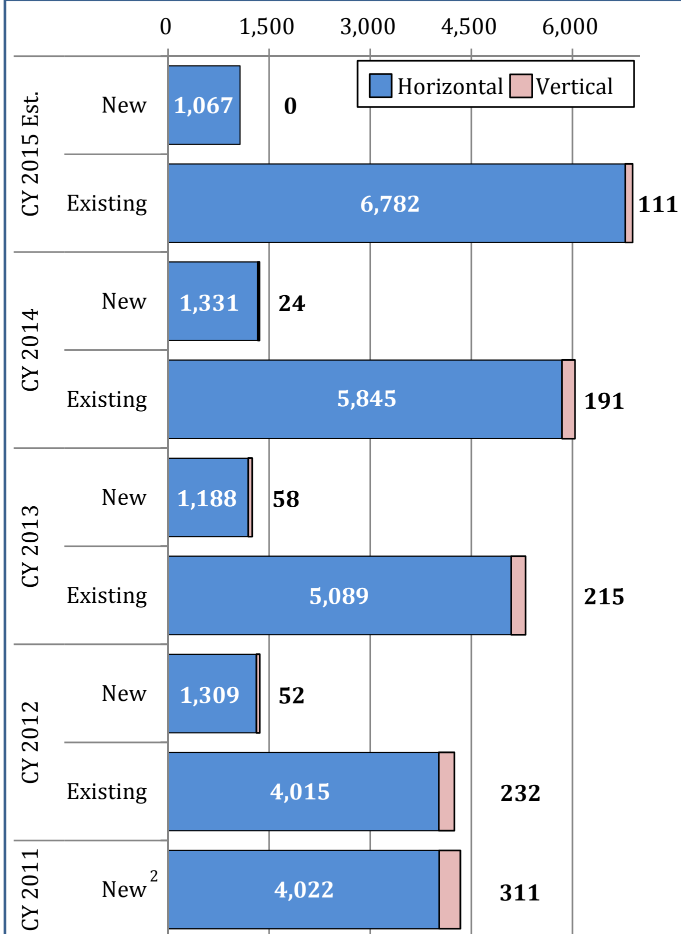
Source: Pennsylvania Public Utility Commission.
[1] Vertical wells are subject to 20% of the fee levied on horizontal wells.
[2] Includes a regional inflation adjustment of 0.6% as reported by the Pennsylvania Public Utility Commission.
[3] The impact fee schedule is forecast to decline because it is based on the annual average price of natural gas on the New York Mercantile Exchange. BENTEK Energy projects that the price of gas will remain below the $3.00 per MMbtu statutory threshold, resulting in a $5,000 reduction for most operating years. A similar adjustment occurred in CY 2012.

The PUC reports the following well counts that motivate CY 2014 impact fee revenues:

- 1,355 new wells (in operating year 1);
- 6,036 existing wells (1,225 in operating year 2, 1,303 in year 3 and 3,508 in year 4); and
- 973 stripper wells that are not subject to the impact fee (not shown in Figure 1). This figure includes horizontal stripper wells in their fourth operating year and vertical stripper wells.

For CY 2014, impact fee revenues total $223.5 million, which is based on the published fee schedule and well counts displayed in Figure 1.[3] Those revenues differ from previous years in two respects. First, CY 2014 was the first year that the number of unconventional wells spud in Pennsylvania exceeded the number spud in the prior year. Due to that outcome, the statute requires the PUC to apply a regional inflation adjustment to the fee schedule. The inflation adjustment increased collections by an estimated $1.2 million. Second, CY 2014 was the first year in which horizontal stripper wells were eligible for an exemption after paying the fee for three years (i.e., in their fourth operating year). The horizontal stripper well exemption reduced collections by an estimated $7.4 million. For CY 2015, a baseline scenario suggests that 1,067 new wells and 6,893 existing wells could be subject to the impact fee. The final section of this research brief provides additional detail regarding that and other potential scenarios.

Figure 1: New and Existing Wells[1]



Source: Pennsylvania Public Utility Commission and Pennsylvania Department of Environmental Protection. The CY 2015 baseline scenario by the Independent Fiscal Office.
[1] New wells are spud in the corresponding year and remit the impact fee. Existing wells were wells spud in prior years and remit the impact fee.
[2] The first year of the impact fee was CY 2011. All wells in that year were classified as new, regardless of spud date.

Table 3: Impact Fee Annual Effective Tax Rates					
Calendar Year	Impact Fee Revenues	Unconventional Production (MMcf)	Price of Gas ($/Mcf)[1]	Market Value[2]	Annual ETR
2011	$204,210	1,064,000	$3.60	$3,830,400	5.3%
2012	$202,472	2,043,100	$2.14	$4,372,200	4.6%
2013	$225,752	3,102,800	$2.89	$8,967,100	2.5%
2014	$223,500	4,051,400	$2.60	$10,533,600	2.1%

Note: Dollar amounts in thousands. MMcf is million cubic feet. Production data as of June 23, 2015.
Source: Pennsylvania Public Utility Commission, Department of Environmental Protection and BENTEK Energy.
[1] Dominion South spot price converted to dollars per Mcf using Pennsylvania heat content, net of post-production costs.
[2] Does not include natural gas liquids (NGLs); 2014 NGL production raised the market value by approximately $100 million.

Effective Tax Rate

Because the impact fee does not directly respond to the price of natural gas or the volume of production, it does not provide a measure of tax burden relative to the value of natural gas production. For that purpose, this research brief computes an average effective tax rate (ETR).[4] The ETR is equal to annual impact fee revenues divided by the total market value of unconventional natural gas production. The market value is equal to the product of (1) the annual average regional price of natural gas net of post-production costs and (2) the total production from all unconventional wells. For CY 2014, the market value of unconventional natural gas produced in Pennsylvania was $10.5 billion. (See Table 3, represents market value at the wellhead.)

The ETR represents an average rate for all wells in operation during the year. In general, older wells with low production will have higher ETRs, while new wells with higher production will have lower ETRs.

The ETR computation for CY 2014 uses these data:

- Annual production of more than four trillion cubic feet. This figure is based on statewide well production data published by DEP.
- An annual average price of $3.41 per Mcf, prior to the deduction of post-production costs. The price is based on trades at the Dominion South hub. (See page 4 for additional detail.)
- Post-production costs of $0.81 per Mcf. This amount includes costs for gathering, processing and transporting gas to markets. Such costs are deducted to approximate the value of gas at the wellhead, the point at which producers calculate their tax liability in states that levy a severance tax. “Wet” gas from the southwestern portion of the state incurs higher processing costs to separate natural gas liquids. Therefore, the post-production costs deducted from the price are a weighted average of $1.46 per Mcf for wet gas and $0.76 per Mcf for dry gas.[5]

Since CY 2011, the annual ETR has declined in each successive year. (See Table 3.) The main cause of that trend was the dramatic increase in production over the time period. For CY 2014, the ETR of 2.1 percent represents a reduction of 0.4 percentage points from the CY 2013 level. The decline in the CY 2014 ETR was motivated by an increase in production (30.6 percent). If prices had remained stable, then the decline in the ETR would have been greater.

Regional Price of Natural Gas

For the impact fee, the price of natural gas is an important factor that determines the relative tax burden on natural gas production. The Henry Hub spot price is often used as a proxy for the price of natural gas throughout the United States.[6] The Henry Hub is a market center in Louisiana that provides interconnections between pipelines, access to processing plants, temporary storage between trades and an electronic trading platform to facilitate instantaneous price discovery. It is also a delivery point for futures contracts traded on the New York Mercantile Exchange (NYMEX).

There are dozens of smaller natural gas hubs located in other states, including several within Pennsylvania. Historically, the prices quoted at these Pennsylvania hubs have tracked closely to the Henry Hub, so that the Henry Hub price served as an effective proxy for the price Pennsylvania producers received for their gas. However, beginning in summer 2014, prices at the Pennsylvania hubs diverged dramatically from the Henry Hub, and the Henry Hub price no longer served as a reliable proxy for regional prices. (See Figure 2.) This price divergence was due to factors such as strong regional production gains, insufficient storage and pipeline capacity constraints. Current information suggests that regional pipeline constraints may continue through 2017 or 2018, therefore the disparity between national and regional prices may persist for several years.

As a result, this brief does not use the Henry Hub as a proxy for regional prices. Rather, this brief uses the Dominion South price, which is the most active trading hub in the Marcellus region. As shown by Figure 2, the Dominion South spot price was significantly lower than the Henry Hub for the last half of 2014, and a sizable differential currently exists. The price trends for the other Pennsylvania hubs mirror this pattern.[7]

Due to expanding production and insufficient transportation infrastructure, analysts project low spot prices for the Dominion South hub for the remainder of 2015. For the purpose of this research brief, the IFO did not make a projection of CY 2015 production. If such a projection were made, the unusually low spot price would be used to compute the market value of production and the ETR. However, recent investor presentations suggest that producers may have hedged between 50 to 90 percent of their CY 2015 production, and may effectively receive a price that is roughly $1.00 to $2.00 higher than the real-time spot price. This financial gain to producers must be offset by an equal financial loss to another entity. Hence, the spot price is the appropriate price to use for an average ETR computation because it reflects the net value to consumers and society, as well as all financial gains and losses associated with production.[8]

2015 Outlook

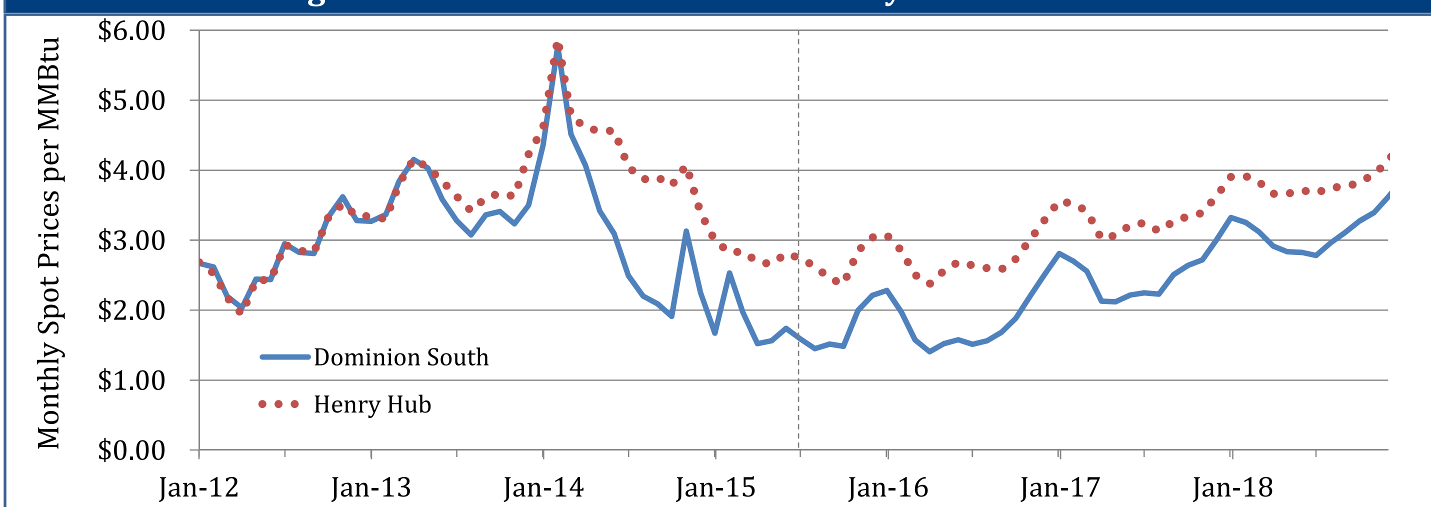
For CY 2015, three factors suggest that impact fee revenues could decline significantly. They include:

(1) <u>The statutory fee schedule will decline based on current and projected prices.</u> The schedule is based on the average price of natural gas on the NYMEX, which is projected to fall below $3.00 per MMBtu for CY 2015. At that price, per statute, the impact fee will decline by $5,000 per well compared to CY 2014 levels. (Only wells in operating year 3 would be unaffected.) BENTEK Energy forecasts that the Henry Hub spot price (on which the NYMEX is based) will average $2.72 per MMBtu for CY 2015. For the first six months of 2015, the NYMEX price ranged from $2.53 to $3.01, with an average of $2.83. Futures prices on the NYMEX currently reveal an average price of $2.86 for the remainder of the year.

(2) <u>The number of new wells spud will decline substantially.</u> DEP spud data from January through June 2015 reveal an approximate 30 percent decline in the number of new horizontal wells spud (no vertical wells have been spud in 2015 to date). Wells in their first year of operation pay the impact fee at the highest level. Revenues from new wells are important to total impact fee collections because they offset the decline in fees received from existing wells as they age. (See Table 4.)

(3) <u>Existing wells pay lower fees over time and many qualify for the stripper well exemption.</u> For example, a well spud in CY 2014 paid a fee of $50,300. That same well will pay a fee of $35,200 for CY 2015. The stripper well exemption, which applies to horizontal

Figure 2: Dominion South versus Henry Hub: 2012-2018



Source: BENTEK Energy.

wells in operating years 4 and 5, will apply to more wells in CY 2015. According to the most recent data from DEP, 252 horizontal wells in operating year 4 and 468 horizontal wells in operating year 5 now qualify for this exemption.

Table 5 displays three potential scenarios for CY 2015 impact fee revenues. All scenarios (1) assume a NYMEX price that is less than $3.00 per MMBtu and the associated reduction in the fee schedule, and (2) reflect a net increase in the number of wells subject to the impact fee because the number of new wells exceeds attrition due to the stripper well exemption. The differences between the scenarios are the number of wells spud and the number of wells qualifying for the stripper well exemption.

- Under the No Change scenario, the number of horizontal wells spud does not change from the CY 2014 level. The scenario also assumes that no additional wells achieve stripper status for the remainder of CY 2015. The scenario demonstrates that even under very optimistic assumptions, CY 2015 impact fee revenues will decline substantially if the fee schedule is reduced due to the low NYMEX price.
- The Baseline scenario reflects a more plausible outcome. It assumes that the number of new wells spud falls by 20 percent and an additional 25 wells achieve stripper status for CY 2015. This scenario yields a $27.4 million reduction in impact fee revenues.
- The Current Trends scenario assumes that spud trends through June continue for the remainder of the year (30 percent reduction) and an additional 50 wells achieve stripper status for CY 2015. This scenario yields a $33.9 million reduction in impact fee revenues.

Table 4: Share of Impact Fee Revenues

CY	Wells	Revenues	Share
2015[1]	New	$48,400	24.7%
	Existing	$147,700	75.3%
2014	New	67,100	30.0
	Existing	156,400	70.0
2013	New	58,608	26.0
	Existing	167,144	74.0
2012	New	59,673	29.5
	Existing	142,799	70.5

Note: Dollar amounts in thousands.
Source: Pennsylvania Public Utility Commission.
[1] Figures reflect lower fee schedule and Baseline scenario.

Low regional prices motivate much of the recent decline in drilling activity. DEP production reports through April 2015 also reveal significant unused production capacity. The reports show 973 wells currently spud but not completed and 760 wells that are shut-in. This large inventory of non-producing wells, as well as low spot prices, suggest that new drilling activity will not offset reductions from the first half of the year.

Although impact fee revenues may decline, low regional prices imply a much higher ETR for CY 2015. Going forward, new pipeline capacity should facilitate a recovery in regional gas prices, an increase in the market value of gas production and lower ETRs. The level of future ETRs will depend on regional prices, production levels and impact fee remittances. By CY 2018, BENTEK Energy projects that regional prices will revert to their CY 2013 levels and production will nearly double from that year. If those assumptions hold and impact fee revenues do not change ($226 million), then the computed ETR would fall by roughly half from CY 2013 (2.5 percent) to CY 2018 (1.3 percent).

Table 5: CY 2015 Impact Fee Revenue Scenarios

	No Change	Baseline	Current Trends
Total Revenues	**$208,600**	**$196,100**	**$189,600**
Difference from 2014	-14,900	-27,400	-33,900
Lower Fee Schedule	-30,400	-30,400	-30,400
Reduction New Wells	0	-12,100	-18,100
Net Existing Wells[1]	15,500	15,100	14,600

Note: Dollar amounts in thousands.
Source: Well counts estimated using data through April 2015 from the Department of Environmental Protection.
[1] Reflects change in revenues from (1) more wells subject to impact fee (new wells less new stripper wells) and (2) the net impact from existing wells aging and migrating down the fee schedule.

Endnotes

1. The annual average price of natural gas is the settled price for near-month contracts on the New York Mercantile Exchange, which is based on the delivery price of natural gas at the Henry Hub in Louisiana.

2. A well that is spud but not "completed" has been drilled, but all of the necessary steps to produce gas remain unfinished. A well that is "shut-in" has been spud, completed and is able to produce gas, but remains idle at the discretion of the producer.

3. The PUC reports impact fee collections of $223.5 million for CY 2014. Approximately $600,000 in revenues is assumed to be remittances for prior calendar years.

4. An alternative to the annual average ETR is the lifetime ETR, which is the average rate over the lifetime of a single, new well; this measure is best used to quantify the prospective tax burden on new wells across states. (See the IFO's previous publication, *Natural Gas Extraction: An Interstate Tax Comparison*, for an analysis using the lifetime ETR.)

5. Post-production cost estimates are from Range Resources investor presentation, June 3, 2015.

6. A spot price is a cash price paid for "immediate delivery," which is often the next business day. Spot prices are unique to each transaction and are commonly averaged per day, month, or year. In addition to spot trading, producers also hedge prices for a large share of their production, using futures contracts and other complex instruments such as swaps, options or privately-negotiated agreements. These strategies may yield a higher average price than the daily spot price.

7. The selection of Dominion South as the proxy for the price received by Pennsylvania producers was confirmed by industry sources. The criterion used was the volume of gas traded at the hub rather than the total flow passing through, since it is the volume traded that receives the price. The hubs considered in this analysis were limited to those located within Pennsylvania, because it was more certain that their trade volume reflects gas that originates from Pennsylvania wells. These are the hubs known as Dominion South, Transco-Leidy, TGP Zone 4, and TETCO-M3. When weighted by the volume of gas traded, an average of the four hub prices does not differ enough from Dominion South to significantly change the ETR calculation.

8. Hedged prices may vary widely based on the specific circumstances of the contracting parties, with very little publicly-available information. Without access to proprietary data, it is not possible to compute an average difference between spot and hedged prices.

Data Sources

- Statewide production data for natural gas wells are from the Pennsylvania Department of Environmental Protection and can be found at https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/Welcome/Welcome.aspx.
- Act 13 impact fee public data are from the Pennsylvania Public Utility Commission and can be found at http://www.puc.state.pa.us/filing_resources/issues_laws_regulations/act_13_impact_fee_.aspx.
- Natural gas price and production forecast data are from BENTEK Energy and can be found at http://www.bentekenergy.com/index.aspx.

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