STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to consider the appropriate regulatory response to proposals by various producers of natural gas from Antrim Shale Formation to operate their wells under a vacuum.	Case No. **U-16230** (e-file/paperless)

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THE MICHIGAN PUBLIC SERVICE COMMISSION STAFF'S INITIAL BRIEF

MICHIGAN PUBLIC SERVICE COMMISSION STAFF

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I. Introduction

This case is the first of its kind in Michigan. For over 30 years the Commission has required natural gas producers to obtain Commission approval before placing wells on vacuum, but these are the first applications to be decided. The applications surface now, after prolonged dormancy, because gas reserves in the Antrim Shale Formation are dwindling and the Applicants[1] believe that implementing vacuum operations will extend the economic life of their projects. Unfortunately, not all producers are convinced that vacuum operations will have this effect. The Intervenors[2] argue that producers will burn more gas running the compressors used to go on vacuum than they will gain through vacuum operations. The Intervenors also contend that vacuum operations will jeopardize their correlative rights. At the same time, there is concern that vacuum operations will introduce harmful oxygen levels into the gas stream that will damage treatment facilities and corrode steel pipes. Staff addresses each of these issues at length in this brief and summarizes its positions here:

- Vacuum operations are unlikely to cause waste.

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[1] Staff refers to the following companies collectively as "the Applicants": Linn Midwest Energy, LLC; Linn Operating, Inc.; Terra Energy Company, LLC; BreitBurn Operating, LP; BreitBurn Management, LLC; Enervest Management Partners, LP; Belden & Blake Corporation d/b/a Ward Lake Energy; Enervest Institutional Fund IX, LP; and Merit Energy Company, LLC.

[2] Staff refers to the following companies collectively as "the Intervenors": O.I.L. Energy Corp.; Atlas Gas & Oil Company, LLC; Jordan Development Company, L.L.C.; HRF Exploration & Production, L.L.C.; and Trendwell Energy Corporation. There are other intervenors in this case, but Staff refers to them individually by name.

- If Antrim gas producers are permitted to operate wells on vacuum, the evidence indicates that they will increase net production (i.e., recover more gas than they burn to run the compressors used to go on vacuum).
- If vacuum operations do not increase net production, producers have an economic incentive to fully evaluate the effectiveness of vacuum operations before making further investments.

- Vacuum operations would not threaten correlative rights any more than existing pressure disparities threaten correlative rights.
- Vacuum operations are likely to introduce more oxygen into the gas stream, but it is very unlikely that this would result in a combustible mixture. Additional oxygen, however, is a significant threat to treatment facilities and transmission pipelines.

If the parties will agree to implement additional safeguards to protect against the adverse effects of oxygen, Staff recommends that this ALJ propose granting the applications to operate Antrim wells on vacuum.

II. Proceedings

In August 2009, the Applicants filed applications in Case Nos. U-16074, U-16075, U-16076, and U-16079 requesting Commission permission to operate wells on vacuum. Another producer later filed a petition in Case No. U-16190 requesting that the Commission issue a declaratory ruling rather than address the applications on a piecemeal basis. After several producers intervened to oppose vacuum operations, the Commission stayed those dockets and opened this docket to broaden

the scope of the proceeding. The Commission said that it would consider proposals by all interested persons concerning vacuum operations in the Antrim Shale Formation. And it instructed this ALJ to develop a record addressing "the effect that allowing or rejecting such [vacuum] operations might have on the Commission's obligation to protect correlative rights, to safeguard the general public, and to prevent economic waste." MPSC Case Nos. U-16230 et al, Order Opening Docket, Staying Proceedings, and Closing Docket, April 27, 2010, p 7.

Since the Commission opened this docket, the parties have not been idle. Consistent with the Commission's directive to develop a record about the history of production in the Antrim Shale Formation, this ALJ instructed Staff to collaborate with the other parties to prepare a report. Staff filed its report on August 24, 2010. In the meantime, the parties exchanged exhaustive discovery and submitted pre-filed testimony. And in 30 days of hearings, this ALJ and the parties developed a vast record that is nearly 5,000 pages long. This ALJ also admitted over 2,500 pages of exhibits. Staff will not endeavor to summarize this extensive record. Instead, when addressing the issues that the Commission asked the parties to address, Staff discusses the record evidence relevant to those issues. Also, immediately below, Staff provides some context to the issues that it addresses later in this brief.

III. Background

A. The Properties and Production History of the Antrim Shale Formation

The Antrim Shale Formation extends across the northernmost counties in Michigan's Lower Peninsula. Staff Report, pp 6, 9. The depth of the shale varies throughout the formation depending on where it is in the Michigan basin. It varies from 150 feet to 2,500 feet. See Staff Report, p 6; 26 TR 4174. The Antrim formation consists of three layers: the Lachine, the Paxton, and the Norwood. 7 TR 856. Only the Lachine and the Norwood are productive. Together, the Lachine and the Norwood are about 110 feet thick on average. Staff Report, p 5; 6 TR 730.

Drilling began in earnest in the Antrim Shale Formation in the 1980s. By 2009, there were approximately 9,750 productive Antrim wells.[3] 13 TR 2062. The wells reached peak production in the late 1990s when approximately 200 billion cubic feet (Bcf) were being produced annually. Staff Report, p 15. Since then, annual production has declined. By 2004, annual production was down to 150 Bcf. Staff Report, p 15. And by 2009, it was down to 120 Bcf. 25 TR 3992. Nonetheless, the Antrim formation is still one of the largest natural gas fields in the country. 25 TR 3992. Although production is declining, almost 50% of the original gas in place still remains. Specifically, as of 2009, the Antrim has yielded nearly three trillion cubic feet of gas, and approximately two trillion cubic feet remain. 22 TR 3719; 25 TR 3992–3993.

[3] According to the Commission's records, there are now almost 300 more Antrim wells that are not plugged or abandoned than there were when this testimony was filed. The Commission may take official notice of this. See 1992 AACS; R 460.17327.

The Antrim formation is not conventional. In a conventional formation, like sandstone, the rock is very porous. Oil and gas are stored in the rock's pore space, much like water in a sponge. 6 TR 642. Antrim shale is also porous rock, but the pore space is much smaller. 6 TR 643; 26 TR 4184–4185. The shale rock, more commonly referred to as the matrix, is solid organic material consisting of hydrocarbons and clay particles. 6 TR 645; 14 TR 2222. There are also horizontal fractures that run through the matrix that range in size from paper thin to a millimeter in diameter. 6 TR 645–646; 26 TR 4191. The matrix and the fractures together make up the reservoir. 7 TR 858–859.

When a well is drilled in the Antrim, there is some free gas in the fractures and the pore space of the matrix, but most of the gas is adsorbed onto the matrix. 6 TR 643, 663, 665; 16 TR 2730. Adsorbed gas is gas that has chemically reacted with the organic matter in the matrix and is bound by pressure to the rock. 25 TR 3994, 4085; Staff Report, pp 6–7. By one estimate, 90% or more of the gas in the Antrim formation is adsorbed gas. 29 TR 4633. As gas producers remove water from the reservoir, the reservoir pressure declines and gas begins to desorb (i.e., it is released) from the organic matter in the matrix. Staff Report, p 7; 13 TR 2118. The desorbed gas moves from the matrix into the fractures and ultimately into the wellbore. 6 TR 664.

Unfortunately, not all of the gas reserves can be recovered economically. The matrix is relatively impermeable — according to the Intervenors, it is approximately 26,000 times less permeable than fractures — so gas travels slowly through the matrix. 25 TR 3995. After capturing the gas in the fractures and the

gas in the matrix pore spaces near the fractures, producers must reach gas deeper in the matrix. 26 TR 4191–4192. This gas must desorb and move through the matrix to the fracture, through diffusion, before it can be produced. 14 TR 2343. Diffusion is a protracted process in any environment, but especially in a dense matrix. 26 TR 4196; 30 TR 4724. Eventually, therefore, producers will not capture enough gas from within the matrix to justify continued production. 4 TR 122; 25 TR 4140–4141.[4]

B. The Fundamentals of Vacuum Operations

If the pressure in a confined area drops below 0 pounds per square inch gauge (psig), which translates into 14.7 pounds per square inch absolute (psia),[5] the area is said to be on a vacuum. 4 TR 314. Because gas flows from high pressure to low pressure, 13 TR 2164, producers seek to lower the pressure in the wellbore to facilitate gas flow from the reservoir into the wellbore. 7 TR 857; 14 TR 2267. Although the Commission's rules prohibit producers from pulling a vacuum in the wellbore, many producers seek to reduce pressure as low as the rule allows. E.g., 17 TR 2859.

Producers primarily use compressors to lower pressure in the wellbore.[6] By increasing the discharge pressure with a compressor, producers are able to lower

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[4] More information concerning the Antrim formation's properties and production history can be found in Staff's report in document number 0063 in this case's e-docket.

[5] Psig is a unit of pressure relative to the surrounding atmosphere. 13 TR 2073. If a well is being operated at 0 psig, it is being operated at atmospheric pressure (14.7 psia). 25 TR 3995. If the well is operated below 0 psig, it is being operated on a vacuum. 4 TR 86.

[6] They can also lower pressure by increasing the pipe sizes at the well and in their

the pressure upstream of the compressor (i.e., on the compressor's suction side), including in the wellbore. 4 TR 88–90. If a producer increases the discharge pressure enough, it can decrease pressure below atmospheric levels on the suction side and create a vacuum. 4 TR 86–89.

C. Carbon Dioxide and Oxygen in Antrim Gas

It would be an understatement to say that Antrim gas contains elevated carbon dioxide (CO^2) levels. The National Association of Corrosion Engineers (NACE) classifies gas with a CO^2 partial pressure[7] above 15 psig as corrosive. Gas in the Antrim has a partial pressure that far exceeds 15 psig. The average Antrim gas well contains "17% carbon dioxide and transports at pressures as high as 1300 psig *resulting in a carbon dioxide partial pressure of 220 psig*." 24 TR 3765 (emphasis added). NACE defines this partial pressure as excessively corrosive. 24 TR 3918.

If gas from an average Antrim well is excessively corrosive, gas from a mature Antrim well is often worse. Mature Antrim gas wells frequently contain far more CO^2 because CO^2 adsorbs to shale better than methane, so more CO^2 is released in the latter stages of production.[8] Staff Report, p 31. It is common for

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gathering system. 6 TR 682–683.

[7] "Partial pressure" is the pressure at which CO^2 begins to react with oxygen or water. 24 TR 3916.

[8] All things being equal, a mature well will have a higher CO^2 content than it did when it was first drilled. Even comparing different wells, mature wells will often have a higher CO^2 content than newly drilled wells. But depending on the location of the wells being compared, it is possible for new wells to have a higher CO^2 content than mature wells.

CO^2 levels in the gas to be as high as 30% in a mature Antrim gas well. 12 TR 1899; Staff Report, pp 31–33.

When oxygen and water are present, this carbon-dioxide-rich gas is even more corrosive. 24 TR 3765, 3917. Gas with a 17% CO^2 content and an oxygen content over three parts per million is highly corrosive. 24 TR 3753. In fact, gas with any amount of CO^2 and oxygen is corrosive. 24 TR 3911. Together, CO^2 and water create carbonic acid, which will corrode metal. Likewise, oxygen and water oxidize metal to create rust. 24 TR 3835.

In addition to being corrosive, oxygen degrades the aqueous amine solution used in CO^2 treatment facilities by interacting with the amine solution to create heat-stable salts. Amine degradation inhibits the amine's ability to remove CO^2 and hydrogen sulfide from the gas stream. 12 TR 1967. The more oxygen that is present in the gas, the quicker it degrades the amine solution. 24 TR 3821.

IV. Discussion

A. Jurisdiction and the Burden of Proof

1. The Natural Gas Act authorizes the Commission to prevent waste in the production, piping, and distribution of natural gas.

The Department of Environmental Quality (DEQ), Office of Oil, Gas and Minerals, and the MPSC share jurisdiction over the state's natural gas resources.[9] The Natural Resources and Environmental Protection Act vests jurisdiction with the DNR (now the DEQ), while the Natural Gas Act (Act 9) grants authority to the

[9] Formerly, the MPSC shared jurisdiction with the Department of Natural Resources (DNR), but sometime after the DNR was divided, the DEQ assumed responsibility over drilling.

MPSC. See generally 1994 PA 451; MCL 324.301 *et seq*.; see also 1929 PA 9; MCL 483.101 *et seq*. Traditionally, the DNR and DEQ have not exercised their jurisdiction over natural gas wells once they have been drilled and classified as natural gas wells:

> Pursuant to these statutes, the commission and the DNR have determined that proration of natural gas wells is properly a matter of commission jurisdiction. As a practical matter, once a well is drilled, the DNR scrutinizes the well logs and other data to determine if it should be classified as an oil or gas well. If, pursuant to its original jurisdiction, the DNR classifies the well as a gas well, jurisdiction is transferred to the commission.
>
> For nearly 47 years, the DNR and the commission have interpreted Acts 9 and 61 [the former Act 61 has been incorporated into the Natural Resources and Environmental Protection Act] to mean that once a well is classified as a natural gas well, jurisdiction is transferred from the DNR to the commission as a matter of course. [*In re Federated Natural Resources Corporation*, MPSC Case No. U-970, Opinion and Order, June 3, 1986, p 7 (Attachment 1 to this Brief[10]); see also *Northern Michigan Exploration Co v Public Service Comm*, 153 Mich App 635, 643; 396 NW2d 487 (1986) and 1979 AC; R 460.855(1).]

Under Act 9, the MPSC has authority to implement rules and regulations to prevent waste and conserve natural gas. 1929 PA 9; MCL 483.114. The Commission also has broad authority to "do all things necessary" to regulate production, piping, and distribution in order to conserve natural gas. *Id.* As a function of its regulatory authority, the Commission is charged with preserving the public peace, safety, and convenience. *Id.*

Consistent with its authority under Act 9, the Commission promulgated rules governing the production and transmission of natural gas. The rules provide that

[10] Because this case was not available in the Commission's case index, it is included as an attachment.

while wells are under the Commission's supervision, it is the chief engineer's duty to regularly gather production data from all wells, fields, and pools. 1979 AC; R 460.855(3)(d). The Commission's chief engineer is also responsible for inspecting the maintenance and operation of gas wells "with a view to preventing waste of gas, damage to gas producing strata or formation, or injury to life or property . . . ." 1979 AC; R 460.855(3)(b).

In the rules, "waste" is defined to include "the wasteful use of gas . . . in its natural state in engines or pumps where its pressure is the main or direct operating force" as well as "the equipping, operating, or producing of any well or wells in such a manner as to reduce or tend to reduce the total quantity of gas ultimately recoverable from such pool." 1979 AC; R 460.857(2)(b),(d). These definitions of "waste" are pertinent here because one issue in this case is whether gas burned in the compressors used to reduce pressure exceeds the gas gained from reducing pressure. If the gas gained exceeds the gas that is consumed in vacuum operations, the vacuum operations are not wasteful.

2. The Applicants must prove, by a preponderance of the evidence, that vacuum operations do not waste natural gas and that they are in the public's interest.

The Applicants bear the burden of proof in this proceeding. In its Order opening this docket, the Commission placed the burden on the Applicants when it said, "[T]he Commission directs that the burden of going forward and the risk of non-persuasion should be with those seeking to have the Commission authorize the production of gas from Antrim Shale Formation under vacuum." MPSC Case Nos.

U-16230 et al, Order Opening Docket, Staying Proceedings, and Closing Docket, April 27, 2010, p 7.

The Applicants must satisfy their burden by a preponderance of the evidence. This is the standard that Michigan courts apply in all civil cases, and it is the standard that the Commission applies in Act 9 cases. *Martucci v Ballenger*, 322 Mich 270, 274; 33 NW2d 789 (1948); *In re Michigan Consolidated Gas Company's application for relief under 1929 PA 9*, MPSC Case No. U-11461, Opinion and Order, January 19, 1999, pp 31, 43. It is well-understood in Michigan jurisprudence that the preponderance of the evidence standard means "more likely than not." *Prisk v Tyler*, unpublished opinion per curiam of the Court of Appeals, issued December 15, 2009 (Docket No. 291468), slip op, p 3 (citing *Skinner v Square D Co,* 445 Mich 153, 165; 516 NW2d 475 (1994), etc.). In other words, preponderance of the evidence means "such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth." *People v Pugh*, 48 Mich App 242, 245; 210 NW2d 376, 378 (1973).

There is no doubt that the Applicants must prove their case by a preponderance of the evidence; it is more difficult to define exactly what they must prove. Neither the Commission's rules nor Act 9 provide much guidance. They impose obligations on the Commission and define the scope of its authority, but they do not establish specific standards for producers wishing to begin vacuum operations. For example, the Commission's vacuum rule (1979 AC; R 460.867) only requires application and notice; it does not place any other burden on petitioners.

The rule does, however, give the Commission broad discretion to "take such action as it deems advisable":

> No gas well, pool or field shall be placed under vacuum by the use of compressors, pumps or other devices except with the approval of the commission. If and when the placing of a vacuum in any well, pool or field is planned, application for approval shall be made to the commission, and the adjoining lease owners and operators of a pool or field who may be affected shall be given notice. The commission may call a hearing on the subject, or *may take such action as it deems advisable*. [1979 AC; R 460.867 (emphasis added).]

Act 9 does not address vacuum operations at all, but it does grant the Commission broad discretion to make decisions concerning natural gas production. As already mentioned, the Commission is obligated to prevent waste and to "do all things necessary" to regulate production, piping, and distribution in order to conserve natural gas. 1929 PA 9; MCL 483.114. Further, it is the Commission's responsibility to preserve the public peace, safety, and convenience. *Id.* In short, the Commission is charged with preventing waste and protecting the public's interests.

The Applicants' burden can only be understood in light of the Commission's obligations. The Commission apparently recognized this in its order opening this docket. It instructed this ALJ to develop a record that addresses "the effect that allowing or rejecting [vacuum] operations might have *on the Commission's obligation* to protect correlative rights, to safeguard the general public, and to prevent economic waste." MPSC Case Nos. U-16230 et al, Order Opening Docket, Staying Proceedings, and Closing Docket, April 27, 2010, p 7. Thus, to satisfy their

burden, the Applicants must prove that vacuum operations do not prevent the Commission from fulfilling its obligations.

The Commission's decision, on the other hand, must be supported by competent, material, and substantial evidence on the whole record. Const 1963, art 6, § 28. Substantial evidence is more than a scintilla of evidence, but it may be substantially less than a preponderance of the evidence. *DaimlerChrysler Corp v State Tax Comm*, 482 Mich 220, 247; 753 NW2d 605 (2008). One witness's testimony can be substantial — even if there is conflicting evidence — if it is offered by a qualified expert who has a rational basis for his or her views. *Mayor of City of Lansing v Public Service Comm*, 257 Mich App 1, 20; 666 NW2d 298 (2003) (superseded by statute on other grounds as described in *City of Lansing v State*, 275 Mich App 423; 737 NW2d 818 (2007)).

B. Vacuum operations are unlikely to waste gas.

When deciding whether vacuum operations contravene the Commission's rules by "tend[ing] to reduce the total quantity of gas ultimately recoverable," the Commission must determine whether vacuum operations will increase the amount of natural gas that producers' ultimately recover and, if so, by how much. Once this is determined, the only other question is whether producers will use more fuel to reduce pressure than they gain through vacuum operations.

In this section, Staff explains why it believes that vacuum operations will increase the ultimate recovery and why, on balance, it appears that producers will gain more gas through vacuum operations than they consume in the process. Staff also explains how producers track fuel consumption so that even if producers begin

to consume more gas than they gain, they would not do so for long. It would not be in their best economic interest.

1. Producers will recover incremental gas from the Antrim formation if they are permitted to further lower pressure and operate wells on vacuum.

Common sense dictates that vacuum operations will increase ultimate gas production in the Antrim — this is illustrated in the discussion below about abandonment pressures. Indeed, the Applicants and Intervenors both projected that vacuum operations will generate incremental gas, but they used different methods that led to a disagreement about the extent of these incremental volumes. While the Applicants used actual data, the Intervenors used a simulator to project incremental gas production. As will be explained, the Applicants' methods are superior to the Intervenors' for several reasons.

a. Lowering the abandonment pressure increases the ultimate recovery.

"Abandonment pressure" is the pressure measured when a well is abandoned — typically when it is no longer economical to continue production at the well. 4 TR 126; 14 TR 2192; 23 TR 3124–25. Several witnesses testified that reducing the pressure at a wellhead lowers the abandonment pressure, which in turn increases the well's ultimate recovery. 5 TR 548–550; 6 TR 740; 11 TR 1611–1612. The Applicants' witness Larry Todd Tetrick used a simple example to illustrate this concept:

> JUDGE EYSTER: Can you explain to me how you came to the conclusion that the ultimate amount of gas recovered will be increased?

> THE WITNESS: If you had a cube, a cube of rock or just say an open vacant cube and you had liquid in it -- well, no. We need to say gas. If that cube has 100 PSI of pressure on the gas and you completely vacated that cube of that gas you would be down to zero pressure within that cube. So, essentially you recover all the gas. If you only -- if you limit yourself to maybe two PSI or five PSI that's still on that cube when you say that's your abandonment then you've left gas in that cube. So, you have waste. You've left that in the reservoir. So, the lower the pressure the lower the abandonment pressure ultimately you will recover more of the gas. . . . [6 TR 740.]

The abandonment pressure can even be used to calculate a well's or reservoir's natural gas reserves. The Applicants' witness Jay Prudhomme explained how engineers use abandonment pressure to extrapolate ultimate recovery in a conventional reservoir and how the same basic principle applies in the Antrim formation:

> One way to estimate reserves in a conventional sand or reservoir is through material balance. It's pressure over a compressibility factor on a graph versus cum.
>
> * * *
>
> And when you are able to shut in wells and shut in and get a stabilized reservoir pressure, you can plot that versus cum and extrapolate that out to whatever your abandonment pressure is to get an estimated ultimate recovery. *With the Antrim, it's not applicable* because, due to the matrix porosity, it would take an unreasonable amount of time to get a stabilized pressure. *But the basic concept still applies*, whereas *if you lower the abandonment pressure, that line will extrapolate out further and increase your estimated ultimate recovery.* So even though material balance isn't practical, it's still applicable in theory. [5 TR 549–550 (emphasis added).]

Where there is an artificial, legal limit on the minimum wellhead pressure, like here, this limit restricts the amount of gas that can be recovered from the reservoir:

Q When you go on vacuum you're producing more gas than you would normally I assume, hypothetically.

A Yes, sir.

* * *

Q So, your production rate would go up. You would have then a decline in your potential reserves, though, wouldn't you, because you're producing them faster? I'm talking about the decline rates, not in volume.

A That's all based on abandonment pressure. If you're lowering the ultimate pressure that you plan to draw a reservoir down to, instead of zero PSI you plan to go to minus ten inches of vacuum you'd recover more reserves. That's -- in some cases that may be a dramatic statement, but that's general engineering principles for a petroleum engineer or a petroleum geologist.

Q The issue there is a matter of time. *You could stay at the other pressure and produce down to that abandonment, couldn't you?*

A *Not if the abandonment pressure was limited to zero.*

* * *

JUDGE EYSTER: *So, legally right now there's an abandonment pressure.*

THE WITNESS: *Yes, sir.*

JUDGE EYSTER: That the Commission has set.

THE WITNESS: Yes, sir.

JUDGE EYSTER: Which is at no vacuum.
[6 TR 670–671 (emphasis added).]

By lifting the legal minimum pressure in Michigan, the Applicants reason that they will be able to produce more gas than they could otherwise.

b. The Applicants used better evidence to project the amount of incremental gas that can be recovered through vacuum operations.

Both sides agree that vacuum operations increase the total recoverable gas reserves in the Antrim formation, but the parties dispute the amount.[11] Vello Kuuskraa, who testified on the Intervenors' behalf, said that field-wide vacuum operations would only marginally increase gas reserves throughout the Antrim formation. He used a simulation to project that a typical Antrim well would produce 4 million cubic feet (MMcf) more gas than the same well would have produced if it had operated at 0 pounds per square inch gauge (psig). 25 TR 3997–3998. He calculated that 4 MMcf per well equates to an additional 39 billion cubic feet (Bcf) over the entire Antrim formation, which only amounts to 0.8% of past production and remaining reserves. 25 TR 3999.

The Applicants, by contrast, maintain that widespread vacuum operations will significantly increase the total gas recovered throughout the entire reservoir. Whereas Mr. Kuuskraa estimated that field-wide vacuum operations would increase gas reserves in the Antrim by 0.8%, the Applicants' witness Steven Kohler calculated that if 50% of all wells in the Antrim were placed on vacuum (i.e., the 50% most suited for vacuum), total gas reserves in the Antrim would increase between 3.7% and 8.9%. 13 TR 2081–2083.

Mr. Kohler used actual data from 18 different wells to project incremental recovery at those wells and, ultimately, over the whole Antrim formation. 13 TR

[11] The Intervenors also dispute whether placing a well on vacuum will increase recovery enough to justify the additional fuel used to go on vacuum.

2080. Producers provided Mr. Kohler with well production plots collected during a pressure drawdown at the 18 wells. 13 TR 2077; Exhibits A-16 and A-17. Based on this information, he "comput[ed] the volume of gas produced from the date the casing pressure was first reduced, to the date when the gas rate return[ed] to its original starting point." 13 TR 2078. He chose the Wild West B3-9 well as an example to illustrate how he calculated incremental recovery:

> In the case of the B3-9, this starting point on August 21, 2006 was 52 MCFD. As of the end of the test data, December 11, 2006, gas rate was still 61 MCFD, well above its starting point. *Therefore all the volume of gas produced during this time I attribute to incremental recovery. The total volume of gas was 6,431 MCF*, and we know this to be only a portion of the total because the well was still producing at incremental rates at the time the test data ended. [13 TR 2078–2079 (emphasis added).]

He repeated this calculation for each of the 18 wells that he analyzed. Using a weighted average, he calculated that the wells would produce, on average, an additional 3.5 Mcf per day for each psi reduction. 13 TR 2080. And assuming that the average well has a -12 psi vacuum capability, he determined that wells would produce 42 Mcf more per day and a minimum of 36,348 Mcf more over the life of the well. 13 TR 2080. Collectively, he projected that total gas reserves in the Antrim would increase between 3.7% and 8.9%. 13 TR 2080–2083; 13 TR 2627–2629. Given the sheer volumes that Mr. Kohler said could be recovered through vacuum operations, it is no surprise that he testified that allowing vacuum operations would prevent waste. 13 TR 2167.

Using the same data, but a different method, Mr. Kuuskraa concluded that Mr. Kohler's incremental production was ten times too high. 25 TR 4009. Mr.

Kuuskraa said that Mr. Kohler overestimated the incremental gas by assuming that all of the gas produced during the pressure drawdown was incremental gas. 25 TR 4008–4009. According to Mr. Kuuskraa, this was not all incremental gas because the great bulk of the gas produced after reducing pressure at the wells would have been produced anyway. 25 TR 4009. Mr. Kuuskraa's calculation, on the other hand, accounted for gas that the wells would have produced if the pressure had never been reduced.

For example, Mr. Kuuskraa multiplied Well B3-9's pre-pressure-drawdown, daily production data (52 Mcf per day) by the number of days that it was operated at reduced pressure (111 days). The resulting figure (5,772 Mcf) is the amount that Well B3-9 would have produced if the pressure had not been reduced. Mr. Kuuskraa subtracted this amount from the actual production data for the 111 days that Well B3-9 was operated at reduced pressure (6,431 Mcf) to calculate that the well's incremental recovery was 659 Mcf. *Id.* This was far lower than Mr. Kohler's projected incremental recovery for Well B3-9, which was 6,431 Mcf.

In rebuttal, Mr. Kohler countered that Mr. Kuuskraa misunderstood the incremental volume that he was computing. Mr. Kohler's goal was not to calculate short-term incremental gas production, like Mr. Kuuskraa, but to project incremental recovery "over the life of the project." 18 TR 2961. Where Mr. Kuuskraa attempted to calculate incremental production for each day that the wells were on vacuum, Mr. Kohler was only interested in long-term production trends. See 13 TR 2960–2961. He had no reason to subtract the gas that wells would have produced anyway — without the pressure drawdown — because all the gas

produced during the drawdown was gas that would not have been produced over the life of the project if there had been no drawdown.

Mr. Kohler again explained how he used sample data from 18 test wells to calculate the ultimate incremental gas recovery over the life of the wells. He began by plotting two decline curves projecting 1) the ultimate recovery if pressure had remained stable after the drawdown and 2) the ultimate recovery if pressure had never been reduced. He then compared the two curves to determine the ultimate incremental recovery:

> *I used the Gas Rate vs. Cumulative Gas plots to estimate how much the prevailing decline curve line has been shifted to the right* (in the direction of higher cumulative gas) by the drawdown of casing pressure. This is represented by the total volume of gas which has been produced since the casing pressure was pulled down. If the casing pressure had not been reduced, I can project what the ultimate gas production would have been by extrapolating the decline prior to pulling down the casing pressure on the Gas Rate vs. Cumulative Gas plot. However, now that the casing pressure has been pulled down the gas rate has increased. *If at the end of the test period, the well is still producing gas at rates in excess of those being produced before the well was pulled down, this reflects an incremental reservoir voidage*[12] *which would not have occurred if the casing pressure had not been reduced.*

Mr. Kohler revisited the data from Well B3-9 to illustrate. The well was capable of producing at 52 Mcf per day at 10 psig before the pressure drawdown. But after reducing its casing pressure to 6 psig, its production rate rose to 61 Mcf per day. Mr. Kohler testified that its production would gradually decline from this new high

[12] Mr. Kohler described incremental gas voidage as the amount of gas that would have been left in the ground if the producer had not drawn the casing pressure down. 18 TR 3121.

back to 52 Mcf per day. All the gas that it produced in the meantime was incremental recovery that would not otherwise have been produced. 18 TR 2962.

On balance, the Applicants submitted better evidence to support their projections. For example, Mr. Kuuskraa assumed that the Applicants would place all their wells on vacuum when he calculated incremental recovery, while Mr. Kohler assumed that the Applicants would only place 50% of their wells on vacuum. Compare 25 TR 3999 with 13 TR 2081. Mr. Kohler's assumption is more reasonable. It is based on information that 50% of Antrim wells produce 70% of the production rate. 13 TR 2081. Producers also independently verified this assumption. Although two witnesses said that they would like to place all their Company's wells on vacuum, neither could say with certainty that they would be able to place all their wells on vacuum. 9 TR 1181; 10 TR 1362–1363. Other witnesses said that not all their wells are good candidates for vacuum, and Mr. Tetrick specifically said that half of Belden & Blake Corporation's wells may not be good candidates for vacuum. 5 TR 472; 6 TR 677.

The Intervenors' projections are also questionable because there is evidence that Mr. Kuuskraa's simulation model was not properly calibrated to represent the typical Antrim shale operations. Mr. Ozgen used Mr. Kuuskraa's model parameters to calculate the incremental benefit of using 80 acre spacing, relative to 160 acre spacing, and found that 80 acre spacing was not economical under the model. Because this did not comport with reality — there is currently an 80 acre spacing requirement in the Antrim — he concluded that Mr. Kuuskraa's simulation model

was not properly calibrated and "not realistic enough for prediction of future behavior." 29 TR 4517, 4519–4520.

Contrary to the Intervenors' simulated projections, the Applicants' projections are more reliable because they used actual data to calculate ultimate recovery. In addition, Mr. Kohler used relatively simple and common concepts to apply the data to real life situations. And although the Intervenors attempted to refute the Applicants' projections using the Applicants' own data, Staff is not convinced. As explained above, the Intervenors rebutted the Applicants' long-term projections with their own short-term assessment, but this apples-to-oranges comparison does not advance their argument.

In sum, everyone agrees that vacuum operations will increase total recoverable gas reserves in the Antrim formation, but the parties dispute the amount. Staff accepts the Applicants' projections because they are based on actual data and because the Intervenors' simulated projections were unrealistic.

2. Compressors used to reduce wellhead pressure burn more gas than they otherwise would, but not as much as producers gain by reducing pressure.

The Applicants' witness James Holt explained how compressors create a vacuum: "A compressor is going to take a suction pressure and raise it to a higher discharge pressure," and by increasing the discharge pressure, the compressor creates a lower pressure on the suction side. 4 TR 88–90. If a producer increases the discharge pressure enough, it can decrease pressure below atmospheric levels on the suction side (upstream of the compressor) and create a vacuum. 4 TR 86–89. But this requires additional fuel because producers will have to generate more

horsepower to increase the discharge pressure. See 4 TR 160–161. Mr. Holt compared it to a car, "[T]he harder you push on the foot pedal, the more gas you burn." 4 TR 161.

The Applicants' witnesses indicate that vacuum operations produce enough additional gas to justify the gas being burned to create a vacuum, but they were short on specifics. The rule of thumb is that it takes ten cubic feet of gas per hour to generate one horse, 4 TR 160, but none of the Applicants attempted to estimate how much more horsepower they would need to pull their wells down to vacuum. Mr. Tetrick, for instance, admitted that a compressor would burn more gas if it were used to go on vacuum, but he was hesitant to guess how much more gas a compressor might consume. 6 TR 704–705. Still, he testified that if a producer could increase production on several wells, even if only by a minimal amount, this would typically justify increasing horsepower on a compressor. 6 TR 709.

The Intervenors' witness, Vello Kuuskraa, disagreed. Mr. Kuuskraa testified that producers would burn more gas fueling compressors than they would recover from vacuum operations:

> *My opinion is that the use of vacuum operations on Antrim Shale gas wells in Michigan would lead to inefficient outlays of energy given that more natural gas would be required to compress the total produced gas stream from -14 psig to 0 psig than the gain in natural gas recovery.* For example, the additional recovery of 4 MMcf per well of natural gas from installation and operation of vacuum (-14 psig) in 20 years is equal to an additional gas production rate of 0.5 thousand cubic feet per day ("Mcfd") of natural gas. To achieve this, the entire 20 year gas production stream averaging 32 Mcfd (234 MMcf of gas recovery, which is the difference between the 490 MMcf of total gas recovery less the 256 MMcf of gas recovery during the first 10 years of operation, divided by 20 years and 365 days per year) from the well placed on vacuum would need to be compressed back to atmospheric (0

> psig) as was the case before installation of vacuum operations. Compressing 32 Mcfd of gross gas production from -14 psig to 0 psig requires 1.8 Mcfd (assuming 1,000 Btu per cf) based on information from the standard industry handbook (Michael R. Lindeburg, PE "Mechanical Engineering Reference Manual for the PE Exam", Eleventh Edition, Copyright 2001 Chapter 32 Gas Compression Cycles), and our calculations of fuel requirements using this information. *The 1.8 Mcf per day of fuel requirements are more than the 0.5 Mcfd gained from installing vacuum operations. Essentially, it would take more gas to fuel the compressors than what incremental volume of gas would be recovered by way of vacuum operations.* [25 TR 4017 (emphasis added).]

Mr. Kohler refuted Mr. Kuuskraa's testimony. As already discussed, Mr. Kohler calculated that the ultimate incremental recovery would be much higher than Mr. Kuuskraa projected. He said that Mr. Kuuskraa's "short-lived and low volume production increase forecast" was inconsistent with the actual data. 18 TR 2963–2964. And even if Mr. Kuuskraa correctly estimated the fuel requirement for vacuum operations (1.8 Mcf per day per well), it is significantly less than Mr. Kohler's projected incremental recovery of 42 Mcf per day per well. See 13 TR 2080.

Since Staff assigns greater weight to Mr. Kohler's projected incremental recovery, Staff concludes that producers will gain more gas through vacuum operations than they use to lower pressure. Furthermore, regardless of the disparity between the gas consumed to reduce pressure and the resulting incremental recovery, producers have a financial incentive to discontinue vacuum operations when it is no longer economical. And as Staff explains in the following section, this incentive is sufficient to protect against waste.

3. Producers can track fuel consumption to determine if a pressure drawdown is economically justifiable.

Both Mr. Holt and Mr. Tetrick confirmed that producers can track the fuel they consume in their compressors. When asked what the fuel usage is for a midsize compressor, Mr. Holt said that he could not answer that without knowing whether the compressor is operating at full capacity, but if he knew how many horses the compressor is generating, then he could calculate how much fuel is being consumed. 4 TR 160. Likewise, Mr. Tetrick, when asked how much additional fuel a CPF compressor would consume if it were used to pull wells down to vacuum, said that he did not have that information with him. Nonetheless, he said that producers have a good idea how much additional fuel it would take to go on vacuum because many of the compressors are already being used to reduce pressure. 6 TR 704.

The additional fuel required to pull a well down to vacuum influences producers' decisions to reduce pressure. The Applicants' witnesses Mr. Jones, Mr. Prudhomme, and Mr. Tetrick all agreed that they consider fuel consumption when making decisions to reduce pressure at a well. 4 TR 319; 5 TR 426–427; 6 TR 708. Mr. Prudhomme explained how producers account for this cost:

Q. And do you also include the fuel cost [for the compression]?

A No, sir.

* * *

Q And why wouldn't you include that, it's a cost, isn't it?

A It's not a -- *it is a cost, but it does not fall under our expense that we're paying out to other.*

Q It's an out-of-pocket expense, though?

A It's less revenue, it's not an expense.

Q It's less revenue because you're not selling the gas?

A Correct.

* * *

A *But that fuel gas would be factored in to the economics of the project, because when you're looking at the final production rate after vacuum, that has the fuel gas taken out of it, the additional fuel gas taken out, so it would be factored in.*

* * *

Q So you'd have less volume basically for sales?

A Yes. [5 TR 425–427 (emphasis added).]

Because producers consider fuel costs when deciding whether to reduce pressure at a well, and because they are not likely to reduce pressure if it is not economically justifiable, it is Staff's opinion that vacuum operations will not result in waste.

C. Producers are in the best position to determine whether vacuum operations are in their economic interests.

Gas production is a function of economics as much as it is engineering. But while regulators have a responsibility to ensure that wells are drilled and operated consistent with conventional engineering specifications, regulators do not oversee producers' economic decisions. Ultimately, it is the producers who invest in infrastructure and development. They bear the financial risk, so they should have the flexibility to make management decisions affecting their pecuniary interests.

This means, for the purposes of this case, that if nothing else prevents the Commission from approving vacuum operations, economics should not either.

1. In the natural gas production industry, regulators have traditionally not regulated purely economic decisions.

The parties debated the economic advisability of vacuum operations in this case. The Intervenors appear to believe that the compressors and other equipment necessary to go on vacuum will cost more than the revenue generated from vacuum operations. But the testimony on this subject is of little consequence because economics should not be a deciding factor. This is consistent with the principles of free enterprise that have long dominated this country's natural gas industry. As the Applicants' witness Chet Ozgen testified:

> Q (By Mr. Sattler): In all your testimony today and in your prefiled testimony, I'm not sure you offered an opinion on the ultimate question in this case, which is whether or not the Commission should allow producers to place wells under vacuum. What's your position on that question?
>
> A My position is, it's more philosophical than scientific, to be frank, because there isn't really enough scientific data here to come to conclusions that were reached by others, and my position has been that the work that is presented here doesn't support those immediate conclusions. *In terms of philosophical approach, I believe that the companies should decide on what they should do, and that has been our system.* And to give you an example –
>
> JUDGE EYSTER: What do you mean that has been our system?
>
> A In terms of application of new technologies, and obviously there have always been regulations, but if -- and this is a hypothetical case -- if somebody had stopped drilling of horizontal wells or in, whether it's first time application in Prudhoe Bay, Alaska, or in United States at least, or the Austin Chalk *that was developed by people who just took chances, and shale gas was exactly the same thing*, a tight gas was like that 15 years ago, people try to

> do different new things, and a lot of them have failed, some of them eventually succeeded, which opened up tremendous resources for the country. And after tight gas, we have shale gas, now we have shale oil. *I believe that people have to make mistakes, companies have to make mistakes, but they have to try different things to increase recovery. And constraining that, to me, philosophically, is not correct*, but it's obviously your choice and it's not really mine. [30 TR 4757–4759 (emphasis added); see also 13 TR 2087–2088.]

Regulators typically do not interfere with producers' business decisions, and this case should not be an exception. The Intervenors' witness Richard Sandtveit testified that Trendwell Energy Corporation only drills wells or re-hydraulically fractures wells if it is economically justifiable. 17 TR 2882–2886. And he admitted that no government agency reviews the economic basis for the Company's decisions. 17 TR 2882. The same should be true for vacuum operations. If producers and operators do not waste gas or jeopardize the Commission's ability to fulfill its obligations to the public, they should be free to decide what is in their own pecuniary interests. This is not only practical; it is the law.

The Michigan Supreme Court has held that, without specific statutory authority, the Commission may not order a regulated entity to cease non-economic management practices. *Union Carbide v Public Service Comm*, 431 Mich 135, 149-150; 428 NW2d 322 (1988). In *Union Carbide*, the Court considered whether the Commission properly ordered Consumers Energy Corporation to stop operating two generating units out of economic order.[13] The Court acknowledged the Commission's ratemaking authority, but it ruled that "by ordering Consumers to

[13] "Operating a plant 'out of economic order' . . . occurs when an expensive unit is operated even though a more reasonable cost unit is available to the system at the same time." *Id.* at 140 n1 (internal quotation omitted).

cease certain noneconomic management practices, the commission exceeded its ratemaking authority." *Id.* at 150. The Court further held that "the power to regulate does not convey with it the power to exercise general management powers." *Id.* at 151.

The Intervenors appear to be asking the Commission to prevent vacuum operations for economic reasons.[14] The Intervenors' request disregards principles of free enterprise and binding precedent restricting the Commission from prohibiting noneconomic management practices.

2. Producers have access to all the information they need to make well-educated economic decisions about vacuum operations.

Many wells are individually metered to measure production at the wells, and many wells are connected to compressors that are capable of pulling a vacuum.[15] 4 TR 252; 6 TR 817; 11 TR 1716. For a well that is individually metered and located near a compressor, producers can easily reduce pressure at the well and measure

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[14] They also argue that if the Applicants are permitted to operate wells on vacuum, it will force the Intervenors to pay to place their wells on vacuum to protect their correlative rights. 17 TR 2829. Correlative rights are addressed in the next section of this brief.

[15] There are at least two kinds of compressors that can be used to pull a vacuum on a well. For one, there are high-pressure compressors that are typically found in central production facilities (CPFs). These compressors generate between 450 and 1,600 horses and are sometimes capable of pulling vacuum on numerous wells. 4 TR 110–112, 253–254; 6 TR 699–701; 10 TR 1359, 1363-1365; 17 TR 2932–2933. There are also boosters and casing compressors, which are low-pressure compressors that are attached to the gathering system or directly to wells. These compressors generate between 50 and 250 horses and are used to further reduce the suction pressure at nearby wells and increase the discharge pressure in the flow lines. 4 TR 113; 6 TR 699-701, 703; 7 TR 961; 9 TR 1178; 10 TR 1365–1366, 1468–1472; 17 TR 2933–2934.

corresponding production increases. And even if a well is not individually metered or located near a compressor, producers can still test wells using portable meters and compressors. 5 TR 544–545. Mr. Kohler testified that portable compressors are inexpensive. 13 TR 2084. He also explained how he would use portable compressors to identify good candidates for vacuum operations:

> Q. [Y]ou've indicated that you would perhaps in some cases test them with portable compression to determine that [i.e., which wells are appropriate for vacuum]; is that correct?
>
> A That's correct.
>
> Q What results would you look at to make that decision?
>
> A Similar to what was done here on the, my Exhibit A-17 that we looked at for the Corwith Dover, page 3 of 30; I would try to run a test of pulling the vacuum at, say it was an existing producing well where I could get what is its current rate and casing pressure, and *then hook up the vacuum compressor and do a test and see how much does the gas rate increase, and I would want to keep it there for several days at least if possible to see how sustained it was to make sure we're not just looking at a flush production scenario.* And then it would be possible to go back just as at the end of this and do it again, taking the well back to its original pressure and seeing how much that could change, if anything. *Do that on multiple wells to decide whether this was a place that I thought that it was viable to either do a long-term lease or to purchase a compressor.* [16 TR 2734–2735 (emphasis added); see also 11 TR 1668–1669 (Mr. Dorr's cross).]

With these means at their disposal, producers should have all the information they need to decide which wells to place on vacuum before they invest in the equipment necessary to do so.

3. Capital costs will not be passed onto royalty owners.

If permitted to operate wells on vacuum, producers would absorb all the capital and labor expenses associated with vacuum operations. 5 TR 580; 11 TR

1744. Although royalty owners would not pay the capital or labor expenses, they would benefit from vacuum operations as long as they produce additional gas. This is true even if producers take a loss:

> Q I think earlier you said you would look at the cost of additional compression. Is that right?
>
> A Yes.
>
> Q And what would you do? How would you do that?
>
> A Well, we use a number of vendors. First of all, we'd do the testing to see, you know, what our projected, over an entire project, projected amount of gas would be. We'd monitor our systems, like we said. And then depending on what we found out, we'd price out if wellhead compression was needed or a main booster at our CPF where we could just pull from a central point, which would be our preference.
>
> Q And what would the factors be that you would take into account to make that decision?
>
> A Incremental rate, gas price, and then any additional cost for that work.
>
> Q *Those additional expenses, who would bear the cost of those?*
>
> A *Our company would.*
>
> Q What would be the effect on royalty owners?
>
> A Royalty owners, *even if it turned out to be non-economic for us the royalty owners would continue to get* -- if there was no payout but an incremental rate they would get *additional revenue* at that point. [11 TR 1732–1733 (emphasis added) (Mr. Dorr's cross).]

Royalty owners would incur some additional fuel costs to reduce pressure, but this merely amounts to less revenue for the royalty owners. 5 TR 425–427; 11 TR 1744.

4. Conclusion.

When deciding whether to place wells on vacuum, producers shoulder the most risk and are in the best position to decide whether vacuum operations are in their economic interests. Economic considerations should not dissuade the Commission from approving vacuum operations.

D. Vacuum operations are not likely to threaten correlative rights any more than existing pressure disparities threaten correlative rights.

There are two reasons why vacuum operations should not cause correlative rights concerns:

- Under current conditions, producers may already be infringing on others' correlative rights. And if the existing threat to correlative rights does not merit a regulatory response, further pressure reductions should not either.
- Although correlative rights are not totally protected, existing regulations and natural conditions provide some protection. As a result, producers' correlative rights are rarely violated. This is not likely to change if vacuum operations are permitted because the same conditions would continue to protect correlative rights.

1. Producers may already be draining gas from adjacent properties, despite the current vacuum prohibition.

The Intervenors recognize that vacuum operations could significantly increase a single well's capacity, but they maintain that this can only be accomplished by draining gas from adjacent wells: "Our modeling reflects installation of vacuum operations by one Antrim Shale operator would lead to

significant capture of gas production from other operator's leases with wells not placed on vacuum." 25 TR 4000. Although the Applicants took issue with the Intervenors' modeling, they did not dispute that a well on vacuum may drain from adjacent wells.

Indeed, any variance in wellhead or regular gathering system pressures can affect correlative rights. If two operators manage wells along project boundaries and one operator reduces the pressure at its wells more than the other — even if the pressure does not drop below atmospheric levels — the pressure differential may allow the first operator to drain gas from the second operator's project. This is because gas flows from high pressure to lower pressure. And if the two wells are connected to the same fracture, all other things being equal, some gas that would have naturally flowed to the nearest well will now flow to the low-pressure well.

Under current conditions, therefore, producers may already be infringing on other producers' and leaseholders' correlative rights. The record supports this conclusion. There is evidence that wells are operated at pressures significantly above 0 psig, while others are drawn down as close to 0 psig as possible. See, e.g., Exhibit I-71 – I-81. Mr. Dorr testified that "[a] pressure difference of 14 PSI between projects would not be uncommon under current non-vacuum operating conditions." 11 TR 1549–1550. If this is true, producers do not need to operate their wells on a vacuum to drain gas from their neighbors.

If the existing threat does not merit a regulatory response, further pressure reductions should not either. Lowering pressure has the same impact whether it is above atmospheric pressure or below it. 17 TR 2902–2903. At present, nothing

prevents a producer from reducing wellhead pressure from 100 or 50 psig to 0 psig. Yet, the same producer may not further reduce pressure to -1 psig. Staff sees no reason to draw the line at 0 psig.

2. For producers and property owners wishing to safeguard their correlative rights, existing regulations provide some protection.

a. Unitization

At many Antrim projects, leaseholders combine their leases to create a production unit; they pool production and divide the royalties based on acreage and royalty interests. 17 TR 2877–2879. Many of these production units are as large as 2,000 acres. 17 TR 2879. Unitization is useful in the Antrim because it is not a homogenous formation; no one knows which wells will tap into flush production and which wells will miss the mark. 14 TR 2324. Through unitization, leaseholders and producers spread the risk by sharing in profitable and unprofitable ventures. There are no correlative rights issues within units. Issues only arise when fractures cross unit boundaries. 17 TR 2879–2880, 2918.

b. Setbacks

The DEQ has established a setback that minimizes correlative rights issues between units but does not provide complete protection. Wells cannot be drilled closer than 330 feet from an adjoining project. 11 TR 1550. Wells are, therefore, less likely to drain gas from adjoining properties because some fractures do not extend that far. 14 TR 2337. But other fractures may run for miles, in which case

the setback would have little impact.[16] 14 TR 2337; 30 TR 4756. In light of the variability among fractures and the potential to drain from remote areas, there is no viable, standard setback that could unequivocally protect correlative rights:

> Q. Please discuss the alternatives to consider with respect to addressing the potential effects that could be created on an offset well by placing of another Antrim well on a vacuum.
>
> A. In my opinion, there are two primary alternatives to be considered in addressing these potential effects. First, one could take the position that an Antrim well will not be approved for operation on a vacuum if it is within so many feet of another Antrim well, lease or project boundary. *I do not believe this to be a viable option given the variability in the Antrim shale fracturing and the benefits to be achieved from vacuum operations.* By adopting a standard setback distance for all wells, vacuum operations would be prohibited at numerous wells where there are limited or no effects caused to an offset well. For reasons I have discussed earlier in my testimony, these wells will not obtain the benefits arising from vacuum operations and the wells will be abandoned earlier in the life of the reservoir leaving more gas in place. *Given this, it does not appear to me that there is any reasonably certain scientific basis to develop a standard setback distance between Antrim wells operated on a vacuum and an offsetting Antrim well, lease or project boundary.* [13 TR 2086–2087.]

Still, the current setback provides some protection. The more distance there is between the wells, the less likely they are to communicate. 14 TR 2337. The current setback will suffice because there is no other viable setback that will totally protect correlative rights.

[16] It is also worth noting that even where there is only a tenuous interconnection between wells, the wells can still communicate with each other given enough time and the right conditions. See 30 TR 4756.

c. Other conditions that also protect correlative rights.

There are at least three other artificial and naturally occurring conditions in the Antrim that further protect correlative rights. First, producers often position wells to protect their interests. Hypothetically, if there is only one well on a project boundary, and if the fracture system feeding that well crosses the project boundary, that well would have unimpeded access to gas in the adjoining property. In reality, however, producers often drill offset wells along lease lines to guard against potential drainage. See 30 TR 4744.

Second, wells must be connected to the same fracture system to meaningfully affect one another. And there must be a strong connection between the wells to cause an immediate impact. If two wells are connected by a complex fracture system, it creates a "tortuous path" between the wells, and it can take years for the wells to communicate:

> Q So one of the goals of this proceeding is to investigate the effect of the vacuum operations on production from neighboring wells, and something that's been discussed is whether or not there's a setoff, a minimum distance between wells, that will ensure neighboring wells aren't affected. Based on your testimony about boundary conditions and how they change over time, *am I correct in assuming that it's not possible to establish a setoff that will guarantee that one well with low pressure won't drain from a neighboring well with higher pressure?*
>
> A Correct. It's -- may I classify, qualify it? *It depends on how conductive and connected the fractures are.* O.K. So if they are really conducted and going, providing communication for miles, then you would expect whatever you do will have an impact for a mile. O.K. *But if the fractures are more complex and they're not really readily connected but they are all over the place and it's a very tortuous path for things to go through, then it may take longer*. It's a matter of -- there will be interference, *it's a matter of time*, and for us to eventually estimate how much time is

> required for this, it can be from a span of time, it can take years. In cases that I've studied in the past, fractured cases, not Antrim, so I can not really relate specifically to Antrim, but *it can be many, many years, but it can be very quick, also.* [30 TR 4756–4757 (emphasis added).]

Third, for a well to drain large quantities of gas from another well, its pressure must be substantially lower than the other well's. There are no-flow boundaries between wells where "the molecules on this side will flow to this well and the molecules on the other side will flow to the other well . . . ."[17] 29 TR 4539–4540. These outer boundary conditions may change if a producer lowers the bottom-hole pressure and increases production. 29 TR 4538–4539; 30 TR 4744. The more that a producer lowers pressure, the more it will affect boundary conditions by draining gas from farther in the fracture system. See 17 TR 2902. Small changes will only have a slight impact on boundary conditions, and if both producers equally reduce their wells' bottom-hole pressures, it may not change the status quo at all. See 29 TR 4539. To significantly alter the status quo, therefore, a producer must dramatically increase or decrease a well's bottom-hole pressure vis-à-vis another well.

These three conditions ensure that producers do not typically infringe on other producers' or leaseholders' correlative rights. Actual data supports this conclusion. Mr. Kohler looked at data from numerous wells in the Antrim and saw little evidence that wells were communicating. 18 TR 3061. Because he only observed a few wells that were communicating, he concluded that it is not common

[17] This assumes that the two wells are in communication.

in the Antrim. 18 TR 3061. The same conditions that protect correlative rights now would continue to protect correlative rights if the vacuum prohibition is lifted.

Moreover, even if wells do communicate, and even if vacuum operations facilitate new no-flow boundaries between wells, there is no guarantee that a change would be inequitable. If the current no-flow boundary favors one producer over another, altering the wells' pressure differential could actually restore equilibrium. As Mr. Ozgen said:

> [I]f I have a well that is producing gas and my neighbor drills a well and I lose gas rate, I could say he just stole my gas, but it could in fact be the other way around; it may be for years I've been draining gas from off his acreage and didn't know it and he finally stopped it by intercepting it. We have no idea where any of the gas that enters any of the wellbores really comes from, so everyone is capturing what is available to their well within the limits of distance or spacing. 16 TR 2664–2665.

3. The rule of capture controls Antrim gas production and will continue to control if the Commission allows vacuum operations.

Under the rule of capture, "[T]he first person to take [oil or natural gas] is entitled to them even though the well drains natural resources from under the land of another." *Northern Michigan Exploration v Public Service Comm*, 153 Mich App 635, 638; 396 NW2d 487 (1986). The rule of capture controls as long as everybody has an equal chance to capture gas in the ground. 11 TR 1652. This is the current situation in the Antrim. Producers compete for gas reserves under their properties, and they compete on equal footing because they are all bound by the same setbacks and vacuum prohibition. 16 TR 2663–2664. This situation would not change if the vacuum prohibition is lifted. As Mr. Dorr testified, "if everybody has a choice to go

on vacuum then it's not a correlative rights issue"; it is merely competitive drainage. 11 TR 1652.

In other formations in Michigan and in other states, the rule of capture usually does not control. More often, states follow the fair share rule, which provides that each surface owner "is entitled only to his equitable and ratable share of the recoverable oil and gas energy in the common pool in the proportion which the recoverable reserves underlying his land bears to the recoverable reserves in the pool." *Northern Michigan Exploration*, 153 Mich App at 638–639 (citation omitted). Equitable shares are usually achieved through unitization or proration. In a conventional formation, if there are two or more producing wells in the same field, and if there is no unitization agreement,[18] "it has been the practice of the Commission to investigate and implement gas proration and daily gas production allowable orders for a natural gas field." 17 TR 2828.

Unfortunately, it is difficult to apply the fair share rule to the Antrim because there is no common pool. Rather than share production from a common pool, operators produce as much gas as possible within units. Operators do not know the exact source of the gas because they don't know how far the fracture system reaches, so there is no guarantee that they are not draining their neighbor's gas. Still, current regulations and existing conditions mitigate potential drainage. Producers may drain small amounts from their neighbors, but they extract most of their gas from underneath their own properties. To the extent that they drain from their neighbors, producers are merely following the rule of capture. 16 TR 2664.

[18] For more on unitization, see Section IV(E)(2)(a), *supra*.

In some instances, if producers do not drain gas from their neighbors, the gas could remain in the ground indefinitely. There is no specific testimony on this point, but it only stands to reason based on what we know from the record. If there is gas within a unit that can only be produced by a well in an adjacent unit (due to the natural fracture system), the gas may never be produced if the adjacent operator is not able to reduce the well's pressure enough. In this scenario, gas would be wasted.

Under the circumstances, it is not the Commission's responsibility to ensure that producers do not drain from underneath each other. In all likelihood, that is already happening — even if it is rare — and where it is happening, it could be preventing waste. All that the Commission can do is ensure that the producers are operating on a level playing field. Vacuum operations do not interfere with that objective. 13 TR 2087.

E. Vacuum operations jeopardize production equipment.

1. Vacuum operations are likely to introduce more oxygen into gathering systems and transmission lines. This oxygen poses risks that should be addressed before approving vacuum operations.

Operating a gathering system or well under vacuum increases the possibility that oxygen will enter the gas stream through a breach. 6 TR 719–720; 24 TR 3755. Oxygen can flood a system very quickly:

> Q On page 6 of your direct testimony you make a statement to the effect that if a well is operated on a vacuum and a leak occurs, the oxygen levels in the system will rise above 3 parts per million very quickly.
>
> A Correct.

Q *By very quickly, what do you mean?*

A What I mean is if you take anything, any gas in, that's in a vacuum and you open it to atmosphere, it's going to try and equalize the pressure inside of the pipe to the outside of the pipe, therefore, *until the piece of pipe that is in vacuum is normalized or gets to atmospheric pressure, it's going to continue to pull atmospheric air into the pipe.* [24 TR 3953 (emphasis added).]

When air and oxygen mix with the gas, it jeopardizes not only producers' equipment, but also the equipment of noncontributing parties that treat or transport the gas.

a. Gas, together with oxygen, poses a negligible risk of combustion.

Gas is combustible if enough air enters the gas stream and the mixture passes an ignition source. 12 TR 1772, 1867. This, however, is highly unlikely. If air combines with gas containing 70% methane and 30% CO^2 (a typical gas mixture for a mature Antrim well), air must comprise at least 81.7% of the mixture before it becomes flammable. 12 TR 1899–1900; see also Exhibit A-3 (tabulating the flammable limits of various methane – CO^2 mixtures in air). At this level, the gas would consist of 170,000 parts per million of oxygen. 12 TR 1776. To put this in perspective, under the Antrim Oxygen Procedures, shippers are required to limit the oxygen content in gas to three parts per million. Exhibit DCP-2.

Even if air mixes with gas in the proper proportion at a certain point in time, an ignition source would also be required for the mixture to combust. 12 TR 1772.

b. Oxygen is a threat to treatment facilities and pipelines.

Although oxygen poses a negligible explosive risk, it could easily damage equipment downstream of a breach in other ways.[19] CO^2 treatment plants, for example, are at risk on two levels. Oxygen degrades the amine solution used to treat CO^2 and also corrodes steel components at the facility.

DCP's treatment plants use aqueous amine solutions to absorb CO^2 from the gas being treated. Even small concentrations of oxygen react irreversibly with amines to produce heat-stable salts and other corrosive by products. 24 TR 3764. These by products, in turn, corrode the equipment used in the amine-treating process. 24 TR 3764, 3755. The higher the concentration of oxygen the more rapidly the equipment will deteriorate. 24 TR 3764. DCP witness David Bennett quoted from a research report describing how oxygen damages treatment facilities and its components. The report said, in part:

> Oxygen contamination in natural gas can pose serious issues in gas plants, natural gas pipelines, gas gathering systems at production facilities and storage fields, and chemical process user facilities. . . . *In gas processing plants oxygen can cause severe corrosion in piping system components resulting in safety hazards due to gas leaks, costly downtime and unplanned maintenance.* Oxygen is also known to result in degradation of glycol in dehydration systems where the degradation products can include acids, which increase corrosion, as well as aldehydes and polymers. *In amine treating systems, oxygen is known to degrade the alkanolamines to form heat stable salts, the*

[19] Besides a breach, oxygen can enter the gas stream in other ways as well. According to a research report by the Gas Processors Association, "Oxygen in natural gas is generally a result of air ingress, which can occur in low pressure gathering systems and where vapor recovery units are operated. Landfill gas and Coal Mine Methane (CMM) sometimes called "gob" gas are natural gas sources known to have oxygen contamination due to collection at vacuum pressures." 24 TR 3755.

> *presence of which reduces the overall amine available for acid gas removal and increases corrosion rates.* Replacement costs of amine treating chemicals are significant and disposal is of environmental concern. [24 TR 3755 (emphasis added).]

Mr. Bennett knows, from personal experience, oxygen's costly corrosive effects. He testified that a unit was offline at the Antrim Treatment Facility from December 2005 to March 2006 because oxygen corroded the still column (i.e., the distillation column). 24 TR 3754, 3920. The repair cost $1.1 million and forced DCP to curtail 25,000 Mcf each day that the unit was offline. 24 TR 3754. DCP was also forced to make significant repairs to the Warner Plant that DCP purchased in 2009; among other things, it replaced the amine exchanger and all of the amine filtration. 24 TR 3889–3890. The repairs were ongoing when Mr. Bennett testified, but DCP had already spent approximately $4 million. While some of the damage was the result of natural erosion, Mr. Bennett believed that oxygen was responsible for much of the damage. 24 TR 3890.

In addition to damaging treatment facilities, oxygen is a corrosive threat to DCP's gathering system as well as downstream transmission lines and storage facilities. DCP collects gas from producers through its gathering system, which transports the gas from producers' CPFs to a DCP treatment facility. After being treated, gas is delivered to MichCon's Petoskey Sales Line or its Antrim Expansion Pipeline to be moved into storage or transmitted to customers. 24 TR 3805, 3807. Both DCP's gathering lines and MichCon's transmission lines are composed of steel. 24 TR 3805, 3862. Gas that DCP collects through its gathering system contains oxygen. Some oxygen is removed from the gas at DCP's treatment facilities when it

interacts with the amine solution to create heat-stable salts. But some oxygen can pass through the treatment facility and enter downstream transmission lines if the oxygen does not interact with the amines or if it is in gas that bypasses CO^2 treatment to be blended with treated gas. 24 TR 3806–3807; Staff Exhibit S-7 (Mr. Bennett's response to 1-Staff-1(d)). Oxygen increases the probability of corrosion in DCP's gathering lines and in downstream transmission lines. 24 TR 3808–3809, 3834–3835.

Ideally, oxygen would not corrode the steel lines because there would be no CO^2 or water in the pipes to interact with the oxygen.[20] Unfortunately, this is not the case. We know that there is CO^2 in DCP's gathering system and in downstream transmission lines. Significant amounts of CO^2 pass through DCP's gathering lines before gas is treated at its treatment facilities. And even after it is treated, residual amounts pass through to downstream transmission lines. DCP does not remove all the CO^2 during the treatment process — by contract, the gas contains 2% or less CO^2. 24 TR 3808. Furthermore, although water has historically not been a problem — at least in DCP's gathering system — water could enter a gathering line or transmission line through dehydration upsets.[21] 12 TR 1858; 24 TR 3841–3843.

As for storage facilities, Mr. Bennett, who was previously a supervisor at Michigan Gas Storage, testified that free water collects in storage facilities. 24 TR 3833. Water can enter storage facilities during the withdrawal cycle. He also

[20] Water is essential to corrosion. It can combine with CO^2 or oxygen to corrode steel. 24 TR 3834–3835.

[21] Producers use dehydrators at their CPFs, and DCP uses dehydrators at their treatment facilities. 12 TR 1850–1851; 24 TR 3841–3843.

testified that there is oxygen in the gas that reaches the storage facilities. 24 TR 3834. When the oxygen in the gas interacts with the water in storage facilities, it will create corrosion. 24 TR 3807–3808, 3834.

c. The Antrim Oxygen Procedures are not adequate to protect DCP's treatment facilities.

DCP has numerous receipt monitoring stations along its pipelines that measure gas volumes, but DCP does not have oxygen sensors at its receipt monitoring stations.[22] 24 TR 3896. In the usual course of business, DCP remotely monitors oxygen content at its treatment facilities and, for some facilities, at several locations along the pipelines feeding the facilities. 24 TR 3896–3897, 3899–3900. For example, DCP has installed nine oxygen sensors on the Grands Lacs system that feeds its South Chester plant. 24 TR 3900. But there are 76 receipt monitoring stations in that system and probably even more CPFs, 24 TR 3898–3900, so it is difficult for DCP to pinpoint the source of oxygen using its nine oxygen sensors. If there were oxygen monitors at each CPF or remote monitoring station, it would be much easier to pinpoint the source.

Currently, if DCP detects elevated oxygen levels, it does not stop gas flow at its oxygen sensors. Instead, DCP closes the contaminated pipeline where the pipeline enters the treatment facility, and it attempts to identify the source of the oxygen by speaking with producers and manually inspecting the receipt monitoring stations if necessary. 24 TR 3899–3901. Once DCP identifies the oxygen's source, it

[22] It can manually test the oxygen content at its receipt monitoring stations if necessary. 24 TR 3896.

can isolate the problem area and open the valve at its South Chester plant to restore flow[23]:

> So at that point, if we found an RMS [i.e, receipt monitoring station] meter with high oxygen content, we would shut that RMS meter off entirely and then open up the valve at South Chester, restore the flow minus the production that had high O2, then typically we'd work with the producers and go backwards from the RMS to their production facilities to try and isolate which of the production facilities was contaminating the pipe. [24 TR 3902–3903.]

The current safeguards are not sufficient to protect DCP's facilities or producers' interests. "One offending CPF or receipt point under vacuum may quickly compromise an entire pipeline . . . ." 24 TR 3756; see also 24 TR 3902–3903. In this situation, DCP would be forced to shut in a pipeline or its entire gathering system until it can identify the source of the oxygen. And in the time it takes DCP to identify the source of the oxygen and curtail it, large quantities of contaminated gas could reach DCP's treatment facilities, which could cause "significant operational harm" to the facilities.[24] 24 TR 3756.

The current safeguards are also not adequate to protect producers. If there is an oxygen breach, all producers along the pipeline suffer until DCP is able to isolate the source of the oxygen and restore gas flow. 7 TR 999. Many witnesses testified that their companies had been shut-in or curtailed at one time or another because other producers exceeded the oxygen threshold. See, e.g., 7 TR 967; 7 TR 999; 9 TR

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[23] DCP isolates the problem area by either curtailing gas from the area or shutting it in completely. If it shuts in the area, no gas is permitted to escape. If production is curtailed, DCP "pinches back" a valve that restricts the flow of gas into the rest of its gathering system. 5 TR 489.

[24] Oxygen levels as small as three parts per million (the current threshold) can damage DCP's facilities over time. 24 TR 3913.

1210; 10 TR 1422. This leaves millions of dollars of gas stranded. As Mr. Bennett testified, for one bad oxygen meter reading, DCP could shut in $80 million of gas. 24 TR 3903.

If producers are permitted to operate their wells on vacuum, shut-ins and curtailments will probably happen more often because oxygen is more likely to enter the system as wellhead and gathering system pressures decrease. 24 TR 3755.

There are steps that the parties can take to mitigate potential oxygen damage. Two witnesses suggested revisions to the Antrim Oxygen Procedures that would give DCP the means to quickly identify and isolate oxygen to mitigate the potential harm to itself and producers. As a condition of operating under vacuum, Mr. Bennett recommended that DCP be permitted to install an oxygen monitor and a kill switch at producers' CPFs that would "automatically trigger a valve when the oxygen content exceeds 3 PPM [i.e., parts per million] at a CPF that operates under vacuum and provides gas to the DCP Antrim Facilities." 24 TR 3757. He said, "This condition will ensure that only the specific CPF with non-conforming gas is impacted rather than the entire pipeline and benefits all Shippers, including those not operating under vacuum, by localizing the issue." 24 TR 3757.

The Applicants' witness Mr. Prudhomme proposed a similar mechanism.[25] Like Mr. Bennett, he also proposed the use of shut-in valves that are automatically triggered when oxygen exceeds certain thresholds, but he recommended different thresholds:

[25] Mr. Prudhomme testified on behalf of Merit Energy Company, which also owns a gas processing plant. 5 TR 340.

> If levels of 3 PPM to 10 PPM O2 are detected by the Oxygen monitoring system, then the operator would have 6 hours to correct the issue or the motorized valve would close. If levels of 10 PPM to 29 PPM O2 are detected by the oxygen monitoring system, then the operator would have 20 minutes to correct the issue or the motorized valve would close. Any reading of more than 30 PPM would immediately relay for the valve to close. [5 TR 340.]

Although Mr. Prudhomme and Mr. Bennett initially disagreed about the appropriate threshold for a kill switch, Mr. Bennett said that he believed he could work with producers to reach a mutual agreement. 24 TR 3783.

d. Producers that intend to operate wells on vacuum should take new precautions to guard against harmful oxygen levels.

Staff recognizes that the Antrim Oxygen Procedures are outside the scope of this proceeding as a privately negotiated agreement. Nonetheless, the Commission has authority to place conditions on its approval of vacuum operations as long as the conditions serve a public purpose related to vacuum operations. The Commission's authority in this case is akin to its authority to place conditions on expedited citing certificates. In Case No. U-16200, the Commission conditioned the International Transmission Company's (ITC) expedited siting certificate on certain reporting requirements. Although Act 295 did not specifically delegate authority to the Commission to impose conditions on a siting certificate, the Commission pointed to case law as the source of its authority:

> *[T]he Commission has recognized that it has inherent authority to attach conditions to the grant of a license or certificate. See, e.g.,* the Commission's August 28, 1996 order in Case No. U-11053, p. 29, wherein the Commission explained that:

> Because one of the acknowledged purposes of the recent amendments to the MTA is to streamline regulation, it is readily apparent that ACI's position regarding the Commission's legal authority to adopt a restriction or condition is out of step with the Legislature's intent. Further, courts have ruled on numerous occasions that an administrative agency's authority to place a condition on a license that protects the public interest is inherent in the licensing process. Indeed, as pointed out by the United States Supreme Court in *Frost v Railroad Commission of California*, 271 US 583; 486 S Ct 605; 70 L Ed 1101 (1926), *as a general rule, an agency that has the power to deny a license may grant it upon such conditions as it sees fit to impose in order to protect the public interest.* Accordingly, the Commission finds not only that it has the authority to impose restrictions on licenses, but also the the provision regarding the effective date of ACI's license is necessary to protect the public interest.

In re the application of International Transmission Co for an expedited siting certificate for a transmission line, MPSC Case No. U-16200, Order, February 25, 2011, p 59 (emphasis added).

Producers do not technically require a license or a certificate to operate wells on a vacuum, but they must obtain Commission preapproval. In this way, the Applicants' request in this case is similar to an application for a license or certificate, and the Commission can impose requirements as a condition of approval just like it can for licenses and certificates.

If the Commission approves vacuum operations in the Antrim, Staff recommends that the Commission place conditions on producers that operate wells on vacuum. Specifically, producers should be required to install oxygen sensors and shutoff valves at the outlet of their CPFs and to allow DCP to maintain and operate these sensors and shutoff valves using uniform triggering levels.

In testimony, several producers noted that they currently have oxygen sensors in place with certain triggering levels, but these triggering levels vary between operators. And based on the record, it appears that the triggers were arbitrarily chosen. Indeed, although the Antrim Oxygen Procedures permit DCP to shut in a pipeline if its oxygen content exceeds 3 ppm, some producers have set their oxygen sensors to trigger when oxygen exceeds 5 ppm. E.g., 6 TR 615; 11 TR 1551. With such a high trigger, a producer could supply gas to DCP with an oxygen content that continuously exceeds the 3 ppm threshold in the Antrim Oxygen Procedures.

Producers should not use inconsistent oxygen triggering levels. As Staff has already demonstrated, they are not working. See this Brief, Parts IV(F)(1)(b) and (c), supra. Instead, to protect its assets, DCP should be permitted to operate oxygen monitors at CPFs that feed into its gathering system, and DCP should establish the triggering levels.[26] Logically, if DCP operates oxygen monitors for projects with wells under vacuum, it would use the same oxygen triggers for every project.

Oxygen sensors and shutoff valves with uniform triggering levels would address problems resulting from oxygen that is currently entering the system and oxygen that could enter the system as a result of vacuum operations. Presently, although pressure at the wellhead cannot legally be drawn down to vacuum, gathering systems can be operated under vacuum (the vacuum rule applies to

[26] Since its treatment facilities are at risk, DCP should determine the oxygen levels that it can accept before curtailing or shutting in a pipeline or entire gathering system. If a producer supplies gas to a different carrier for treatment, that carrier should be permitted to install and operate oxygen monitors and establish appropriate triggering levels.

"wells, pools, and fields"; it does not apply to gathering lines). 1979 AC; R 460.867. Indeed, many gathering systems are on vacuum today, and oxygen is more likely to enter a gathering system that is under vacuum. 6 TR 719–720, 829–830; 24 TR 3755. Extending the vacuum prohibition would not do anything to address the current situation, but oxygen sensors and shutoff valves would. They are designed to prevent oxygen from passing downstream, whether the oxygen enters the system through a breach in a gathering system or through a breach at a well.

2. Vacuum operations increase the potential for pipe collapse.

While most materials are designed to withstand vacuum pressure, some material may not possess the structural integrity to withstand vacuum. Some polyethylene pipe used in the Antrim, for example, could collapse if a well is operated at full vacuum.

> Polyethylene pipe often used in underground Antrim gas piping would need to resist collapse pressures exerted by earth and hydraulic loads and internal vacuum. A pipeline operating under full vacuum at a burial depth of four feet would experience collapse pressure in the range of 16 to 18 psi, depending on characteristics of the soil in which it is buried. According to the Plastics Pipe Institute Handbook of Polyethylene Pipe, the collapse resistance of DR 11 pipe is 76 psi at 60°F for a service life of 50 years (DR is the dimension ratio; outside diameter divided by wall thickness). For DR 17 pipe, this value drops to 18 psi. *In this case, the collapse resistance DR 11 pipe provides an adequate factor of safety against collapse but the DR 17 pipe does not.* For the DR 17 material, internal vacuum should be limited so that total collapse pressure does not exceed 50 percent of the pipe's collapse resistance. [12 TR 1773–1774 (emphasis added).]

Although there was testimony that producers generally use SDR 11 as the standard, Staff recommends that the Commission require producers to reevaluate

the materials and the construction methods that they used in systems they intend to operate under vacuum. 6 TR 789; 12 TR 1904. Producers need to ensure the integrity of their systems. They should document all steps taken to ensure that their equipment is in good condition and suitable to withstand vacuum operations, and they should maintain this documentation as long as they operate under vacuum. Further, although many of the gathering lines in the Antrim are not regulated under the Michigan Gas Safety Standards, there may still be gathering systems that are regulated. 2009 AACS; R 460.20101(2); 49 CFR § 192.8(b). In these gathering systems, producers should ensure that they are complying with the Gas Safety Standards.

F. Possible enforcement and remedial measures.

If the Commission does not grant the Applicants' requests to operate wells on vacuum, it should consider how it will enforce the current vacuum prohibition. There are approximately 9750 Antrim wells.[27] 14 TR 2201. The wellhead and casing pressure varies between wells in a project. Even a single well's pressure fluctuates from day to day. For this reason, it is practically impossible to ensure at all times that no well is being operated on vacuum. Mr. Dorr testified to this effect. 11 TR 1651–1652. Granted, it is not necessary to monitor all wells all the time to deter vacuum operations, but further regulatory action is required to discourage violations.

[27] According to the Commission's records, there are now almost 300 more Antrim wells that are not plugged or abandoned than there were during cross examination. The Commission may take official notice of this. See 1992 AACS; R 460.17327.

The primary obstacle to regulation is personnel. Staff does not have the personnel to have a significant presence in the field. Mr. John King, the previous MPSC Gas Operations Section Manager, told Mr. Dorr as much in a conversation about vacuum operations. 11 TR 1651. Another obstacle is access to pressure data. Most wells are not currently equipped with monitoring devices, and producers typically do not manually test their wells' casing pressure more than once a week, if at all.[28] The Commission could require producers to provide the Commission with this pressure data, but since pressure testing apparently is not a standard industry practice, this would not be sufficient to discourage violations. Additional action is required to ensure compliance.

If the Commission permits vacuum operations for the entire Antrim formation, there would be no prohibition to enforce in the Antrim. The rule of capture would control. Before it controls, however, the Commission should consider requiring the Applicants to wait some time before beginning vacuum operations. Many of the Applicants are prepared to go on vacuum immediately after the Commission issues its order in this case, but others are not. 5 TR 437; 11 TR 1731; 17 TR 2850; 21 TR 3447. To eliminate this advantage, the Commission should require producers to delay vacuum operations until all producers have time to install any equipment necessary to protect their property interests. Staff recommends a six-month waiting period.

[28] Mr. Dorr said that BreitBurn Operating, L.P. and Terra Energy Company, L.L.C. monitor their wells' casing pressure with a handheld device on a weekly basis. 11 TR 1591, 1751–1752. But at least one other producer indicated that it rarely tests wellhead pressure. 10 TR 1463–1464.

G. The Commission may wish to impose additional requirements on vacuum operators in the future.

If the Commission approves vacuum operations, it may in the future consider requiring vacuum operators to provide additional information concerning their vacuum operations. Future requirements would likely be the result of discussions with other regulatory bodies, like the DEQ. The requirements should not be overly burdensome to producers, Commission Staff, or any other regulatory bodies. Staff has identified one set of potential requirements for consideration. Namely, any project with a well or wells operating below 0 psig could be designated as a "project under vacuum" and could be subject to the following additional requirements for the life of the wells within that project:

1. All wells within the project would be individually metered for production and reported individually.
2. Together with the production data, producers would provide the typical operating pressure at the wellhead.

Producers are quite capable of installing individual meters on wells in projects under vacuum. Many wells are already individually metered, and two witnesses indicated that they would be willing to add meters or at least report data for wells that are individually metered.[29] 7 TR 817–818; 10 TR 1477. With respect to pressure data, although there is apparently no standard industry practice, some producers already collect pressure data on a weekly basis and others could do so

[29] Some wells are individually metered but not reported individually. Instead, only the project's production is reported collectively. 7 TR 817–818.

with little or no added expense.[30] Producers could then provide this information to the Commission together with production data. If collected on a regular basis, this production and pressure data could be a valuable source of information.

Staff does not recommend that the Commission adopt the above recommendations in its order in this case at this time. Staff may be able to reach an agreement with producers and other interested parties without necessitating official Commission involvement. Thus, Staff merely requests that the Commission recognize its jurisdiction in the matter and provide Staff additional time to review current reporting practices and determine a course of action. Failing this, the Commission may later consider implementing Staff's recommendations.

H. Staff recommends that the Commission apply its decision to all wells in the Antrim.

In its Order opening this docket, the Commission invited "the parties and the ALJ to evaluate whether the Commission should carry out the recommendations to be made in the Proposal for Decision through this single contested case proceeding, serial contested case proceedings, or a rulemaking proceeding." Staff recommends that if the Commission permits the Applicants to place their wells on vacuum, it also approve vacuum operations for all current and future wells drilled in the Antrim formation. If it is acceptable for the Applicants, it should be acceptable for

[30] Mr. Dorr said that BreitBurn Operating, L.P. and Terra Energy Company, L.L.C. monitor their wells' casing pressure with a handheld device on a weekly basis. 11 TR 1591, 1751–1752. And he said that they would be willing to provide this pressure data to the Commission. 11 TR 1752. At least one other producer indicated that it rarely tests wellhead pressure but that there is no reason that it could not do it more frequently. It is not cost prohibitive. 10 TR 1463–1464.

all Antrim producers and operators. This ensures that all producers are on equal footing.

Staff further recommends that the Commission limit its decision to the Antrim formation. If a producer wishes to begin vacuum operations in another formation, the producer's application should be subject to another contested case proceeding. Other formations with different characteristics should be evaluated anew to determine whether they are suitable for vacuum operations. Moreover, even in the Antrim formation, producers that did not file an application in this case should be required to provide notice if they plan to begin vacuum operations. A new contested case hearing should not be necessary, but producers must notify the Commission and adjoining leaseholders and operators to satisfy the requirements in the vacuum rule. See 1979 AC; R 460.867. The notice should identify the projects and wells that the producer plans to place on vacuum.

V. Conclusion

The Applicants bear the burden of proof in this proceeding, and they must satisfy this burden by a preponderance of the evidence. No one knows exactly how much incremental gas that vacuum operations will produce, so no one can say with absolute certainty whether producers will gain more gas through vacuum operations than they burn to go on vacuum. But the Applicants have used actual data to project that producers will, more likely than not, gain more gas through vacuum operations than they burn to go on vacuum. This is all that the Applicants needed to show to satisfy their burden on this issue. And the Intervenors have not successfully rebutted the Applicants' proofs.

The Applicants have also satisfied their burden with respect to correlative rights. Although it is possible for producers who place wells on vacuum to drain gas from neighboring leaseholders, this is possible even without vacuum operations. Once this is understood, it becomes clear that if correlative rights are not an obstacle to current operations, correlative rights should not be an obstacle to vacuum operations either. And, in any event, there is reason to believe that producers rarely infringe on their neighbors' correlative rights and that this is not likely to change if the vacuum prohibition is lifted. The same factors that currently protect correlative rights would continue to protect them.

The one drawback to vacuum operations that legitimately concerns Staff is the potential for elevated oxygen levels. Vacuum operations increase the possibility that large amounts of oxygen will enter the gas stream through leaks or ruptures, which threatens equipment used to treat or transport gas. But the parties to this proceeding can mitigate oxygen's potential adverse effects by implementing additional safeguards. If the parties are able to do this, then Staff recommends that

this ALJ propose approving vacuum operations for the entire Antrim Shale Formation.

Respectfully submitted,

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Dated: July 18, 2012

ATTACHMENT 1

Re Federated Natural Resources Corporation
Additional petitioner: Michigan Consolidated Gas Company
Intervenor: Armand, Inc.
Case No. U-970

Michigan Public Service Commission
June 3, 1986

PETITION *for proration of natural gas wells to provide for equitable sharing of gas produced and sold; granted, on a prospective basis.*

P.U.R. Headnote and Classification

1.
PROCEDURE

s26 - Hearing and notice - Conduct of hearings - Oral argument.
Mi.P.S.C. 1986
A request for oral argument was denied where the commission found that oral argument would be unnecessary, counterproductive, and redundant because the party requesting oral argument had not specified that its purpose would be to supplement the record, but had merely wished to debate the issues raised by the parties in their briefs.

Re Federated Natural Resources Corporation

P.U.R. Headnote and Classification

2.
GAS

s3 - Jurisdiction and powers - State commissions - Proration.
Mi.P.S.C. 1986
By virtue of state statutes, the public service commission has jurisdiction over the proration of natural gas wells.

Re Federated Natural Resources Corporation

P.U.R. Headnote and Classification

3.
GAS

s3 - Jurisdiction and powers - State commissions - Proration.
Mi.P.S.C. 1986
The interpretation by the public service commission of jurisdiction statutes governing natural gas well proration has been upheld by the courts and should not be overturned unless clearly wrong or unless a different construction is plainly required.

Re Federated Natural Resources Corporation

P.U.R. Headnote and Classification

4.
GAS

s3 - Jurisdiction and powers - State commissions - Administrative standards.
Mi.P.S.C. 1986
Standards utilized by the staff and commission for establishing retroactive proration of a natural gas well were found to be sufficiently precise to prevent administrative officials from acting arbitrarily with unbridled authority although the standards were not published and had not been promulgated as rules under the administrative procedure act.

Re Federated Natural Resources Corporation

P.U.R. Headnote and Classification

5.
GAS

s9 - Natural gas fields, wells and connections - Drainage of adjacent property.
Mi.P.S.C. 1986
The commission held that a property owner's failure to act, and not the commission's rules on natural gas proration, had led to the drainage of natural gas

from the property by wells on an adjacent land parcel.

Re Federated Natural Resources Corporation

P.U.R. Headnote and Classification

6.
PROCEDURE

s36 - Stare decisis - Cases resolved by settlement - Precedent.
Mi.P.S.C. 1986
A case resolved by a settlement could not be used as precedent because, in settlements, parties often accept positions which are otherwise not acceptable ***240** in order to gain concessions or avoid the expenses and delays associated with litigation.

Re Federated Natural Resources Corporation

P.U.R. Headnote and Classification

7.
GAS

s9 - Natural gas fields, wells, and connections - Drainage - Proration of production.
Mi.P.S.C. 1986
A property owner is not entitled to a retroactive share of production from a well on adjacent property that drained gas from both parcels of property where the property owner had not developed the capability to produce gas or to receive revenues.

Re Federated Natural Resources Corporation

P.U.R. Headnote and Classification

i.
GAS

s9 - Natural gas fields, wells, and connections - Adjacent wells - Fair share rule.
Mi.P.S.C. 1986
Discussion of the legal development of the "fair share rule," with respect to the extraction of natural gas from the "ownership-in-place" theory and the " rule of capture."

Re Federated Natural Resources Corporation

Before Long, chairperson, and Anderson and McLogan, commissioners.

By the COMMISSION:

Opinion and Order

I.

History of Proceedings

On July 10, 1984, Federated Natural Resources Corp. (Federated) filed a petition for proration of natural gas production from the Washington 10, 10A, and 11 pools in Macomb county. On July 16, 1984, Michigan Consolidated Gas Co. (Mich Con) filed a similar petition.

Pursuant to due notice, a public hearing on both petitions was held on December 19, 1984. Administrative Law Judge Frank V. Strother presided at the initial hearing on behalf of Administrative Law Judge Robert L. Shankland (ALJ), which representatives of Federated, Mich Con, and the commission staff (staff) attended. Federated requested that its petition be amended to narrow the scope of the proceedings to the Washington 10 pool. Neither Mich Con nor the staff objected and the motion to amend the petition was granted.

A second prehearing conference was held on March 5, 1985. It was attended by Federated, Mich Con, the staff, and a representative of Katherine Bowerman-Roy and Armand, Inc. Federated, Mich Con, and the staff acknowledged agreement on the details of an isopach map and appropriate filed rating percentages to be derived therefrom, but indicated that some legal issues did remain. After a brief discussion, it was agreed that Armand would file a petition to intervene which would not be opposed by the other parties. A schedule for the filing of testimony and cross-examination of witnesses was es-

tablished. On March 15, 1985, Armand filed its petition to intervene.

The evidentiary phase of the hearing commenced on June 4, 1985. Prior to the start of testimony, Armand's petition to intervene was granted. Immediately thereafter, cross-examination of the witnesses commenced and continued on June 5, 10, and 17, 1985. At the close of the record, it consisted of 705 pages of transcript and 27 exhibits. Briefs and reply briefs were filed by all parties.

On November 27, 1985, the ALJ issued a proposal for decision (PFD). ***241** On December 23, 1985, Armand filed its exceptions and a request for oral argument before the commission. On January 29, 1986, replies to Armand's exceptions were filed by the staff and Federated.

II.

Positions of the Parties

These facts are not in dispute. The Washington 10 pool is located in Washington township, Macomb county, Mich. It is a Salina-Niagaran reef-type reservoir which is believed to have originally contained approximately 35 billion cubic feet (Bcf) of natural gas. Seventeen wells have been drilled into the Washington 10 pool, and there are numerous dry holes around the pool. All the producing wells were drilled between 1974 and 1981. As of January 1, 1985, the Washington 10 pool had produced 11,399,927 thousand cubic feet (Mcf) of gas.

Federated, a Delaware corporation with offices in Traverse city, Mich., is engaged in the exploration and production of oil and gas in Michigan. Federated owns or controls and is the operator of three wells in the Washington 10 pool.

Mich Con, a Michigan corporation with principal offices in Detroit, is engaged in the distribution and sale of natural gas at retail to approximately 1,000,000 customers. As a part of its overall operations, Mich Con owns and/or operates a number of gas producing wells. Mich Con is the owner of certain leasehold working interests in 14 wells in the Washington 10 pool.

One of the wells drilled into the Washington 10 pool is identified as the Bowerman-Roy No. 2-10 well. The drilling unit upon which this well is located originally consisted of a 40-acre parcel identified as the southeast quarter of the southeast quarter of Section 10, Town 4 North, Range 12 East, Washington township, Macomb county, Mich. (Parcel A). The standard well connection permit application for the Bowerman-Roy No. 2-10 well was filed with the commission on November 24, 1980, and the well has been in continuous production since that date. Immediately to the east of Parcel A is another 40-acre parcel described as the southwest quarter of the southwest quarter of Section 11, Town 4 North, Range 6 East, Washington township, Macomb county, Mich. (Parcel B).

Armand Bowerman and Katherine Bowerman-Roy were brother and sister and until Mr. Bowerman's death in 1981 owned Parcels A and B as joint tenants. All of this property was part of a farm that has been owned by the Bowerman family since 1812. Abigail and Katrina Roy are the daughters of Katherine Bowerman-Roy and her former husband, Dr. David R. Roy.

Armand is a Michigan corporation incorporated on April 1, 1984, for the purpose of taking title to a part of the land owned by Katherine Bowerman-Roy, primarily for estate planning purposes. Katherine Bowerman-Roy has executed a warranty deed for consideration to all rights to approximately 31 acres of land in Parcel B lying west of VanDyke road to Abigail and Katrina Roy. They, in turn, conveyed their interest in this property to ***242** Armand which is solely owned by Abigail and Katrina Roy.

At the current time, all 40 acres of Parcel A are owned in fee simply by Katherine Bowerman-Roy and are under lease to Mich Con. As for Parcel B, Katherine Bowerman-Roy owns approximately 6.5

acres of land on the west side of VanDyke road that she leased to Mich Con on April 1, 1980. Also located on the west of VanDyke are 1.57 acres of land owned by Gerald Choma et al., and .6 acre owned by Ralph F. Buccinno et al. Both of these properties have been leased to Mich Con. The remainder of the land in Parcel B lies to the east of VanDyke road and is owned by Armand, with the exception of a one-half mineral interest in .6 acre of land owned by Dr. Roy. The land in Parcel B lying to the east of VanDyke road has never been leased to Mich Con.

On February 20, 1985, Armand entered into a voluntary pooling and operating agreement with Mich Con, which calls for Mich Con to continue as the sole operator of the Bowerman-Roy No. 2-10 well. It also calls for an expansion of the original 40-acre Bowerman-Roy No. 2-10 drilling unit (Parcel A) to include the 40 acres located in Parcel B, thus making the Bowerman-Roy No. 2-10 drilling unit an 80-acre unit. Armand would be a working interest owner and would pay its fair share of all past, present, and future operating costs and well costs to Mich Con. The amount of the past costs was agreed to by the parties and is dependent upon the outcome of this litigation. If Armand wins, it is obligated to pay Mich Con in excess of $272,000, with payments to be made over 36 months out of production. If Armand loses, the amount it is obligated to pay will be significantly smaller.

The agreement between Armand and Mich Con was reached one day before a scheduled hearing at the Department of Natural Resources (DNR) on Armand's October 25, 1984, petition to enlarge the Bowerman-Roy No. 2-10 drilling unit. As originally filed, Armand's petition with the DNR requested that the Bowerman-Roy No. 2-10 drilling unit be increased to 120 acres. However, following the agreement reached between Armand and Mich Con, Armand's petition for an enlarged drilling unit was revised downward to include the addition of only Parcel B. On March 8, 1985, Armand received an order from the DNR authorizing enlargement of the drilling unit for the Bowerman-Roy No. 2-10 well from 40 to 80 acres (Parcel A plus Parcel B). By its terms, that order became effective March 15, 1985. On May 21, 1985, an application for a standard well connection permit was received by the commission for the enlarged Bowerman-Roy No. 2-10 drilling unit.

Donald J. Mazuchowski, a petroleum engineer in the staff's gas division, presented uncontested testimony regarding the physical characteristics of the Washington 10 pool used by the parties to calculate field index ratings and minimum allowables for the wells drilled into the pool. He stated that because a great deal of well data was available for the Washington 10 pool, Federated, Mich Con, and the staff agreed to prorate the pool through use of the 100% acre-feet proration ***243** method using the isohydrocarbon numbers. He explained that the 100% acre-feet proration method uses the pay rock pore volume underlying a producing unit to calculate field index ratings. The isohydrocarbon number is the product of the porosity, gas saturation, and the feet of net pay. According to Mr. Mazuchowski, this represents the amount of gas-filled pore space under each producing unit. Federated, Mich Con, and the staff agreed that the reservoir pore space volume was 6,731 acre-feet. It was also agreed that Parcel B was underlain by 311.3 acre-feet. Based upon these calculations, it was determined that increasing the size of the Bowerman-Roy No. 2-10 drilling unit from 40 acres to 80 acres increased the Bowerman-Roy No. 2-10 well field rating percentage from 12.74% to 16.95% and resulted in corresponding reductions of the field rating percentages of the other 16 wells.

The only issue that was not resolved by the parties involves the date to which the proration of the enlarged Bowerman-Roy No. 2-10 drilling unit should be made retroactive. Armand argues that the increased field index rating for the Bowerman-Roy No. 2-10 well should be applied retroactively to production from the Washington 10 reservoir after November 24, 1980, the date of the original applic-

ation for a standard well connection permit from the commission. Federated, and the staff, contend that the Bowerman-Roy No. 2-10 well field index rating of 16.95% (based upon the enlarged drilling unit) should only be retroactive to production from the Washington 10 reservoir subsequent to May 21, 1985 (the date the revised application for a standard well connection permit was received by the commission), with the lower field index rating of 12.74% being applied from November 24, 1980, through May 21, 1985.

Armand presented the testimony of two witnesses in support of its position. Jack R. Elenbaas, a consulting petroleum engineer, testified that the commission prorates the production of gas reserves in a common pool in order to ensure that each gas well producing unit in that pool will be allowed to produce its fair and equitable share of the natural gas reserves in the common pool. According to Mr. Elenbaas, the commission accepts the well producing units established by the DNR pursuant to 1939 P.A. 61 (Act 61) and the commission has never attempted to alter a production unit or to prorate a gas field among producing units except where a voluntary pooling agreement has been executed for an enlarged or revised unit. Mr. Elenbaas believed that proration should be imposed retroactively to the date each well producing unit begins to actually drain or deplete the reserves of a common pool to assure that each producing well unit is allowed to produce its fair and equitable share of the common pool as determined by the actual geological distribution of the reserves underlying each unit.

Mr. Elenbaas supported Exh. I-2, an isopach map showing that the Washington 10 pool extends under Parcel B with net pay thickness in excess of 250 feet. Exhibit I-3 is Mr. Elenbaas's isohydrocarbon map which also shows that Parcel B is underlaid ***244** by the Washington 10 pool. Based upon these exhibits, Mr. Elenbaas believed that in excess of 500 hydrocarbon acre-feet underlie Parcel B. This would be equivalent to more than 2 Bcf of the original gas reserves in the Washington 10 pool.

It was Mr. Elenbaas's opinion that the Bowerman-Roy No. 2-10 well had been consistently depleting or draining the original gas reserves underlying the entire 80-acre enlarged Bowerman-Roy No. 2-10 unit from the date the Bowerman-Roy No. 2-10 well first began production. Additionally, he believed that the drilling of a well on Parcel B at any time subsequent to the commencement of production of the Bowerman-Roy No. 2-10 well would have constituted waste. As the Bowerman-Roy No. 2-10 well has drained the 80-acre unit since its inception, it would be arbitrary and unrealistic to treat the 80-acre unit as anything other than one indivisible unit for proration scheduling.

Donald E. Mather, an attorney for Armand, testified that he was retained on August 2, 1983, by Katherine Bowerman-Roy to represent her individually and in her capacity as personal representative of her deceased brother's estate, including a federal estate tax audit conducted by the Internal Revenue Service (IRS) regarding the valuation of the estate's assets. According to Mr. Mather, the IRS had questions about the value of the gas royalty interests held by his clients. Mr. Mather stated that during a June 29, 1984, meeting an IRS agent presented him with a net pay isopach map for the Washington 10 pool which had been prepared by Mich Con on October 24, 1983. Mr. Mather contacted Mich Con and discussed the situation with them. He was advised that Mich Con intended to file a petition for gas proration with the commission. At that time, Mr. Mather consulted with two specialists having backgrounds in oil and gas law and engineering. Based upon their recommendations, he advised his clients to file an application with the DNR to expand the Bowerman-Roy No. 2-10 drilling unit. Subsequently, negotiations resulted in the agreement with Mich Con regarding a voluntary pooling agreement and voluntary unit operating agreement.

The staff supported its position with the testimony of two witnesses. James C. Woodruff, director of the staff's gas division, described the regulatory history of retroactive proration in Michigan. Accord-

ing to Mr. Woodruff, until 1963, the commission had utilized a standard surface-acreage/open-flow methodology of prorating production from gas fields. He explained that this methodology was developed and applied during an era when gas fields were primarily sandstone reservoirs underlying rather larger acreages with relatively thin pay zones. Under such geological circumstances, two-dimensional surface areas provided reasonable proxies for the underlying reservoir rock and a well's deliverability, as measured by open-flow capacity, was an acceptable indicator of the quality of the surrounding pay. Given these circumstances, reasonably equitable take of gas could be accomplished utilizing a formula giving, in effect, equal weight to a well's deliverability and to the surface acreage of its producing unit ***245** with appropriate penalties for off-center locations.

Mr. Woodruff explained that in the late 1950s oil and gas began to be produced from Niagaran reefs which had quite limited areal extent, but very thick pays. By the early 1960s it became evident that the commission would not be able to meet its responsibilities to provide for equitable take from reef-type gas pools if it continued to use a two-dimensional proration formula dominated by open-flow capacity. Mr. Woodruff stated that the staff developed and advocated a proration formula giving 90% weight to pay rock volume and 10% weight to open flow. This so-called ”90-10” formula was adopted by the commission on May 28, 1964, in Case No. U-970 (Ray) and has been used for the proration of most Niagaran reef fields.

Mr. Woodruff stressed that the commission prorates gas production, not reserves. Therefore, if there is only one well in existence capable of draining gas from a reservoir, there is no proration. According to Mr. Woodruff, a working or mineral interest owner has no claim upon produced gas or any share of gas produced from a pool until the capability to capture that gas exists. This means that either a producible well must exist on a producing unit including the working or mineral interest owners' interests or arrangements and agreements have been completed by which the working or mineral interest owners' gas can be produced by someone else's well.

According to Mr. Woodruff, the commission was motivated by a number of concerns to develop and to implement the system of temporary allowable withdrawal orders and retroactive production. The waste and disruption of testing wells to the atmosphere; difficulties in arranging for and validating well tests due to the phase-out of state conducted tests; the absence of alternative testing capabilities; concerns for gas conservation; the need to mitigate environmental and noise pollution; employee health and public safety considerations; and the need for a period cleanup production demanded a regulatory system which could provide for the testing of wells to pipelines without penalizing those with interests in the wells completed after discovery wells. Mr. Woodruff explained that the key benefits to the system of temporary allowable withdrawal orders and retroactive production was a flexible regulatory system that allowed:

1. Issuance of temporary allowable withdrawal orders based on operators' estimates;

2. Production before testing for open-flow capacity;

3. Development of appropriate proration formulas;

4. Equity assurances inherent in retroactive production;

5. Early availability of gas from newly drilled wells.

Mr. Woodruff believed that retroactive production had proven itself to be a viable and acceptable regulatory mechanism which provided the commission with a tool to mitigate or to avoid the abusive use of the law of capture.

***246** According to Mr. Woodruff, the ”proration” of oil wells by the DNR is not the same as the commission's ”proration” of gas wells. He explained that DNR's proration is a conservation function

which limits daily production of oil and gas in order to prevent reservoir damage or underground waste. On the other hand, the commission's proration is an equity function designed to provide for the equitable sharing of whatever volume of gas is produced and sold from a pool. Mr. Woodruff stated that the commission accomplishes its conservation function through the use of allowable withdrawal orders which limit maximum gas production rates for each well.

Mr. Woodruff testified that the commission's "producing unit" differs from the DNR's "drilling unit." According to Mr. Woodruff, the DNR's drilling unit is a geographic subdivision created for well-spacing purposes, while the commission's producing unit is an area in which working and mineral interests have been communitized for gas production purposes. He contended that the DNR has no authority to establish producing units. However, he noted that the staff had consistently required that when there is a DNR spacing order in effect, the commission's producing units must coincide with DNR drilling units or whole multiples thereof. The purpose of this requirement is to ensure that a working interest or mineral interest owner will not be left out of a commission producing unit and also unable to capture his or her gas due to the DNR's refusal to grant a drilling permit for a fractional drilling unit in violation of its spacing order.

John T. King, supervisor of the petroleum engineering section within the gas division, described the transfer of jurisdiction over gas wells from the DNR to the commission. According to Mr. King, the operator of a well must first file an application for a standard well connection permit with the commission, and must include test data, a filing fee, open-flow calculations, and a gas analysis. Secondly, the staff prepares and sends a letter to the geological survey division of the DNR asking for classification of the well. If the DNR finds the well is a gas well, it will transfer jurisdiction over the well to the commission for production regulation.

According to Mr. King, the application for a standard well connection permit for the Bowerman-Roy No. 2-10 well was received by the commission on November 24, 1980. The staff submitted its letter to the DNR requesting well classification on December 1, 1980, and the DNR transferred jurisdiction over the well by letter dated December 19, 1980. Thereafter, the commission issued standard well connection Permit No. 2064 and a temporary allowable withdrawal order on January 21, 1981. A revised allowable withdrawal order was subsequently issued on August 27, 1984, after submission of open-flow test data. In every instance the Bowerman-Roy No. 2-10 well was considered as a 40-acre unit.

Mr. King testified that under the staff's methodology the effective date of retroactive proration for the 40-acre unit would be December 1, 1980, which is the first day of the ***247** month after receipt of the application for a standard well connection permit. Mr. King strongly opposed Armand's position that the expanded 80-acre unit for the Bowerman-Roy No. 2-10 well should be retroactively prorated to December 1, 1980. He reasoned that the existing 40-acre unit was expanded by a communitization agreement apparently to avoid drilling a well on the 40 acres that was added. Mr. King believed that Parcel B should be treated exactly as if a well had been drilled. He argued that if Mr. Elenbaas's position were to prevail, it would cause inequities with respect to each of the other 16 producing units. Further, he stressed that it would be improper for the commission to include acreage that was not leased until recently in retroactive production.

Jerome A. Colligan, executive vice president of Federated, stated that the position taken by Armand, if adopted, would seriously erode the law of capture and prorate gas reserves rather than gas production. Additionally, Mr. Colligan believed that the adoption of Armand's position would penalize Federated for complying with the rules previously established by the commission. He argued that any deviation from the commission's past practice regarding proration would take away gas which

Federated has produced from the Washington 10 field. According to Mr. Colligan, the commission should adopt the staff's position and consider the Bowerman-Roy No. 2-10 well to be an 80-acre unit only as of the date the commission received an application for a standard well connection permit for that well covering that 80-acre unit.

III.

Proposal for Decision

After considering the regulatory history of proration, the ALJ recommended that the position taken by Armand be rejected by the commission. The ALJ first distinguished the commission's proration of the Clarence 19-A pool from the facts of this case. Next, he rejected Armand's argument that the commission is bound by the previous actions taken by the supervisor of wells and must therefore prorate the expanded Bowerman-Roy No. 2-10 unit retroactively to November, 1980. The ALJ also found that the legislature had given the commission jurisdiction over proration of gas wells and that the DNR's statutory authority to establish spacing requirements for drilling units could not be construed to divest the commission of this authority.

The ALJ stated that Armand had no reason to complain of the negotiations which occurred between Federated, Mich Con, and the staff before Armand became a party to this case. He noted that Armand presented no evidence in opposition to the positions reached in the agreement by the other parties despite the fact that it was free to do so. The ALJ also rejected Armand's argument that its proposal will reduce the cost of gas and save money for Mich Con's ratepayers. The ALJ pointed out that although Armand will be sharing in the drilling and completion costs of the Bowerman-Roy No. 2-10 well, Mich Con's gas purchase agreement with Armand will increase its cost of ***248** gas obtained from the well. Finally, the ALJ rejected Armand's contention that equity requires that proration of the Bowerman-Roy No. 2-10 well be made retroactive to December 1, 1980. In so doing, the ALJ expressed concern that Bowerman-Roy family members took no action to protect their interest in gas underlying Parcel B for a number of years despite evidence that Parcel B was underlaid by the Washington 10 pool. Additionally, the ALJ was concerned that adoption of Armand's position would undermine commission policy by discouraging exploration and early production.

IV.

Exceptions

Armand challenges eight rulings of the ALJ and proposes 14 findings of fact. The exceptions concern Armand's arguments that the ALJ has misconstrued the express statutory authority granted to the DNR supervisor of wells, allowed the staff and Federated to collaterally attack an order issued by the DNR, deprived Armand of the right to drain gas under its property, misinterpreted the significance of the commission's decision regarding proration of the Clarence 19-A pool, and allowed the staff to exercise authority without sufficient rules, guidelines, or standards to prohibit an abuse of discretion. Additionally, Armand contends that its position will reduce Mich Con's costs, its predecessors of title were diligent in prohibiting drainage of Parcel B, and its requested relief is fair.

V.

Discussion

Request for Oral Argument

In its request for oral argument, Armand contends that resolution of this matter involves important issues regarding the commission's jurisdiction over the proration of natural gas and the interaction of 1929 P.A. 9 (Act 9) with Act 61. Armand also contends that an adverse ruling from the commission could cost it approximately $275,000 and result in ”serious ramifications” for Michigan's oil and gas

industry. For these reasons, Armand requests the opportunity to present oral argument before the commission.

[1] Rule 40(1) of the rules of practice and procedure before the commission gives the commission discretion to hear oral arguments. In deciding whether to exercise this discretion, the commission must determine whether a full hearing has occurred on the record as required by the Administrative Procedures Act, 1969 P.A. 306, as amended (APA). The APA requires that parties in a contested case be given an opportunity for a prompt hearing, an opportunity to present oral and written arguments on issues of law and policy, and an opportunity to present evidence and argument on issues of fact. Further, the APA allows parties the right to cross-examine witnesses and submit rebuttal evidence. However, once the parties have been granted a fair and impartial hearing in accordance with the full panoply of procedural safeguards guaranteed by the APA, a party***249** does not have the right to demand oral argument before the commission, *Rochester Community Schools Board of Education v. Michigan Board of Education*, 104 Mich.App. 569, 305 N.W.2d 541 (1981).

The record in this proceeding is complete. No additional information is required by the commission to render a decision upon the applications for proration of the Washington 10 pool. To grant Armand's request for oral argument when the commission has before it a full record of evidence, arguments, and exhibits received at the hearing would be unnecessary, counterproductive, and redundant. Armand has not specified that the request for oral argument is based upon an effort to supplement the record. Instead, Armand merely wishes to debate the issue raised by the parties in their briefs. Based on the discussion above, the commission finds that Armand's request for oral argument should be denied.

Proration

At the heart of Armand's first exception is its argument that by passing Act 61 the legislature vested broad authority to regulate Michigan's oil and gas industry with DNR's supervisor of wells. Armand argues that § 13 of Act 61 defines drilling units in terms of the area drained. It contends that proration should equitably apportion the gas in a reservoir among the individual drilling units based on the amount of gas beneath each unit. Armand also stresses that § 24 of Act 61 provides:

"This act shall be cumulative of all existing laws on the subject matter, but, in case of conflict, this act shall control and shall repeal such conflicting provisions, except for the authority given the public service commission in §§ 7 and 8 of Act No. 9 of the Public Acts of 1929, as amended, being §§ 483.107 and 483.108 of the Michigan Compiled Laws."

Armand argues that Act 61 gives the supervisor of wells authority over all oil and gas wells except for the limited provisions of §§ 7 and 8 of Act 9. Armand contends that § 7 of Act 9 merely refers to maximum daily flows and that § 8 grants only a limited authority to prorate natural gas production when full production exceeds supply. According to Armand the past practice of the staff is irrelevant. Instead, as both the commission and the DNR are creatures of statute, the specific statutory provisions of Acts 9 and 61 must be applied. According to Armand, the commission has no authority to disregard Act 61. Armand believes that the commission should accept the DNR's recognition that the Bowerman-Roy No. 2-10 unit consists of 80 acres and drains 80 acres and that the well has drained the 80 acres since the start of production.

[2] To properly determine the commission's jurisdiction over proration of the Washington 10 pool, a review of the relevant sections of Acts 9 and 61 is necessary. In Act 61 the position of supervisor of wells was established in the DNR and regulatory mechanisms to prevent waste and encourage conservation of oil and gas production were put into place. Section 1 of Act 61 declares it to be the public policy of this state to protect ***250** the interest of

its citizens and land owners from unwarranted waste of gas and oil and foster the development of the oil and gas industry along the most favorable conditions and with a view to ultimate recovery of the maximum production of these natural products. The legislature also provided that Act 61 should be construed liberally in order that effect may be given to sound policies of conservation.

Section 4 makes it unlawful for any person to commit waste in the exploration, development, production, handling, or use of oil or gas. Section 5 gives the supervisor of wells jurisdiction and authority over the administration and enforcement of the provisions of the act and all matters relating to the prevention of waste and to the conservation of oil and gas. Section 2 defines waste to include, in addition to its ordinary meaning, underground waste, surface waste, and market waste. If the supervisor of wells feels that the total allowable production for any field or pool should be produced in such a manner as to prevent waste, he or she is to "prorate or distribute on a reasonable basis the allowable production of the producing wells in a field or pool." However, Act 9 vests the commission with similar jurisdiction. By its title, Act 9 gives the commission jurisdiction to regulate the production, purchase, and sale of natural gas, provides for the control and regulation of certain persons by the commission, and defines the powers and duties of the commission. Section 7 empowers the commission to establish the maximum daily flow in any production field. Section 8 provides that:

"Whenever the full production from any common source or field of supply of natural gas in this state is in excess of the market demands, then any common purchaser of such natural gas as herein defined receiving production or output from such source or field shall take therefrom only such proportion of the available supply as may be marketed and utilized without waste, as the natural flow of the well or wells owned or controlled by such common purchaser bears to the total natural flow or production of such common source or field, having due regard to the acreage drained by each well, so as prevent any common purchaser from securing an unfair proportion therefrom; and it shall be the duty of the commission and it is hereby empowered to regulate and enforce the above provision, provided that the commission may by proper order permit the taking of a greater proportion by any common purchaser whenever or wherever it shall determine the taking of such greater proportion reasonable and equitable or conducive to public convenience or necessity."

Pursuant to these statutes, the commission and the DNR have determined that proration of natural gas wells is properly a matter of commission jurisdiction. As a practical matter, once a well is drilled, the DNR scrutinizes the well logs and other data to determine if it should be classified as an oil or gas well. If, pursuant to its original jurisdiction, the DNR classifies the well as a gas well, jurisdiction is transferred to the commission.

***251** [3] For nearly 47 years, the DNR and the commission have interpreted Acts 9 and 61 to mean that once a well is classified as a natural gas well, jurisdiction is transferred from the DNR to the commission as a matter of course. According to *Roosevelt Oil Co. v. Secretary of State,* 339 Mich. 679, 64 N.W.2d 582 (1954) great weight should be given to the construction consistently given to a statute by the executive department charged with its administration. Such construction should not be overturned unless clearly wrong or unless a different construction is plainly required.

The broad authority of the commission to prorate natural gas production under the auspices of Act 9 has recently been upheld by the Ingham county circuit court. In *Northern Michigan Exploration Co. v. Michigan Pub. Service Commission,* File Nos. 82-30061-AA, 82-30077-AA, and 82-30085-AA, Circuit Judge Robert Holmes Bell rejected arguments that Act 61 should be interpreted as conferring upon the supervisor of wells nearly exclusive authority to regulate natural gas production. Judge Bell stated:

"Thus, the first question posed by plaintiffs' jurisdictional challenge is whether the proration order constitutes an exercise of authority conferred upon the commission by either § 7 or § 8 of 1929 P.A. 9, being M.C.L.A. 483.101 et seq.; M.S.A. 22.1311 et seq. (hereinafter, Act 9). If so, then there is no question but that the commission had jurisdiction to issue the proration order.

"Section 7 of Act 9 authorizes the commission to regulate the maximum daily flow of gas from any well:

.....

"Obviously, § 7 does not expressly authorize proration. It does, however, authorize the commission to restrict the maximum daily flow of gas from any well to an amount less than 25% of the daily natural flow 'for good cause shown.' Although 'good cause' is not defined by the statute, the purpose of the statute is instructive as to the legislative intent underlying its language. In *Nelson v. Galpin,* 277 Mich. 529, 548, 269 N.W. 586 (1936), the Michigan supreme court described one purpose of Act 9 as follows:

" 'One purpose of this statute is to permit equitable withdrawal of gas by those interested in a common source of field of supply, for purposes of conservation, and to restrict the daily flow or output to that end.'

"Since the object of the proration order - i.e., to permit each well operator reasonable opportunity to produce recoverable gas beneath his interest - is substantially the same as the above acknowledged purpose of the statute, proration would certainly seem to constitute 'good cause' for restriction of maximum daily flow. Hence, this court is inclined to accept § 7 of Act 9, proffered by the commission in its brief, as a proper basis for commission jurisdiction.

.....

"Sections 5 and 14 [of Act 9] are broad grants of authority:

.....

"Neither of these sections mentions proration. Yet they would both appear***252** to be broad enough to permit proration under the established commission rule, 1979 Administrative Code, R 460.865. Plaintiffs contend, however that § 5 and § 14 were repealed by § 24 of Act 61, *supra,* because the conflict with the regulatory authority of the DNR supervisor of wells.

.....

"It appears ... that by using the word cumulative, the legislature intended that both Acts 9 and 61 should continue to have full vitality in harmonious coexistence. Only in the case of 'conflict' does Act 61 become preeminent, controlling and repealing conflicting provisions.

"In *Miller Brothers v. Michigan Pub. Service Commission,* Docket Nos. 78-2713, 78-2714, Sept. 24, 1979 (Mich.App.) (unreported), the court of appeals had occasion to construe § 24 of Act 61. The court held that 'conflict' refers to the relationship between exercises of authority by different governmental agencies pursuant to different statutory provision, rather than the relationship between the statutory provisions themselves.

" 'Thus in case of an inherent conflict between an *order* issued by the MPSC on this subject and the supervisor of wells, the supervisor of wells'*order* would prevail.' (Id, p. 5; emphasis added.)

"The court impliedly held, in other words, that unless both the commission and the supervisor issued conflicting orders respecting the same subject matter, there would be no 'conflict' which would activate the 'repeal' power of § 24. In the absence of such a conflict, the authority delegated to the commission by Act 9 would appear to be unaffected by

§ 24 of Act 61." (Citations deleted.)

Given the recent judicial affirmation of the commission's jurisdiction to prorate gas wells, Armand's first exception must be rejected.

In its second exception, Armand contends that the staff and Federated are attempting to collaterally attack an order issued by the DNR. Specifically, Armand contends that the DNR has ruled that the Bowerman-Roy No. 2-10 drilling unit should be considered as an 80-acre unit throughout the period of its production. However, the commission believes that the retroactive production methodology utilized by the staff is consistent with the order of the supervisor of wells expanding the Bowerman-Roy No. 2-10 drilling unit to an 80-acre unit. Conspicuously absent from Armand's discussion of the supervisor of wells' March 8, 1985, order is any mention of the effective date. Contrary to Armand's contentions, there is no specific finding of fact that the Bowerman-Roy No. 2-10 well was capable of efficiently and economically draining both Parcels A and B prior to the order's effective date of March 15, 1985.

[4] In its third exception, Armand contends that the standards utilized by the staff and the commission for establishing retroactive proration are unpublished, uncited, and unauthorized by statute. It also argues that the standards and policies "exist only in the minds of the staff." The commission disagrees. As evidenced by the testimony of Mr. Woodruff, the ***253** standards and policies for proration of natural gas by the commission have developed over many years and have been applied in dozens of cases that have been decided by the commission. Additionally, in Order No. 2883, the commission adopted Rule 15(d); 1979 Administrative Code, R 460.865(4), which reads:

"Ratable taking or gas proration: All gas produced from a field or pool in excess of the minimum allowable provided for in subrule (c) shall be taken ratably from all wells that are capable of producing more than their minimum allowable take. Such excess shall be divided among such wells in proportion to their modified open-flow capacities or any other method determined by the commission to be equitable or less wasteful, except that in no case shall the total gas taken from a well be larger than provided for in subrule (A)."

In *Northern Michigan Exploration Co., supra,* the appellants challenged the commission's application of the 90-10 proration method on the ground that it had not been promulgated as rule pursuant to the APA. After noting that natural resources management "is ill-suited for specific regulation," Judge Bell found that the language of Rule 15(d) is "sufficiently precise" so as not to leave administrative officials with unbridled authority to act arbitrarily. The judge also observed that:

"Even in the 1980s, the state of subterranean exploratory technology is not so far advanced as to permit precise estimation of reservoir configuration and contents. In view of these realities, it is appropriate, and indeed necessary, for the commission to retain relatively broad discretion in applying its technical expertise and administrative authority to the task of equitable prorating natural gas production. This discretion is not totally unbridled. Adequate protection from its abuse is provided by the mechanism of judicial review."

[i] In its fourth exception Armand contends that the acceptance of the ALJ's ruling will deprive it of the right to drain gas under its property. However, an examination of Armand's exception reveals that its position is based upon a fundamental misunderstanding of the "law of capture" and the effective date of the order of the supervisor of wells establishing the Bowerman-Roy No. 2-10 well as an 80-acre unit. Although Armand correctly notes that Michigan adheres to the "ownership in place" theory of oil and gas law, it misstates that law. By simply stating that "a surface owner owns the oil and gas beneath his land," Armand ignores the effect [of] the "rule of the law of capture" and the "fair share rule." A comprehensive discussion of these principles is contained in *Wronski v. Sun Oil*

Co., 89 Mich.App. 11, 279 N.W.2d 564 (1979):

"In Michigan, we adhere to the ownership-in-place theory. *Michigan Attorney General v. Pere Marquette R. Co.*, 263 Mich. 431, 248 N.W. 860 (1933) . Under this theory 'the nature of the interest of the landowner in oil and gas contained in his land is the same as his interest in solid minerals.' William and Meyers, Oil and Gas Law, § 203.3, p. 44. Solid minerals are a part of the land in or beneath which are located, *Mark v. Bradford*, 315 Mich. 50, 23 N.W.2d 201 (1946), and ***254** as a consequence the owner of land is also the owner of the oil and gas in or beneath it.

"Oil and gas, unlike other minerals, do not remain constantly in place in the ground, but may migrate across property lines. Because of this migratory tendency the rule of capture evolved. This rule provides:

" 'The owner of a tract of land acquires title to the oil and gas which he produces from wells drilled thereon, though it may be proved that part of such oil or gas migrated from adjoining lands. Under this rule, *absent some state regulation of drilling practices*, a landowner ... is not liable to adjacent landowners whose lands are drained as a result of such operations.... The remedy of the injured landowner under such circumstances had generally been said to be that of self-help - "go and do likewise." ' William and Meyers, *supra*, § 204.4, pp. 55-57. (Emphasis supplied.)

"This rule of capture was a harsh rule that could work to deprive an owner of oil and gas underneath his land. To mitigate the harshness of this rule and to protect the landowner's property rights in the oil and gas beneath his land, the 'fair share' principle emerged.

"As early as 1931, the board of directors of the American Petroleum Institute expressed this principle by declaring a policy:

" '...that it endorses, and believes the petroleum industry endorses the principle that each owner of the surface is entitled only to his equitable and ratable share of the recoverable oil and gas energy in the common pool in the proportion which the recoverable reserves underlying his land bears to the recoverable reserves in the pool.' Graham, "Fair Share or Fair Game? Great Principle, Good Technology-But Pitfalls in Practice," 8 Nat.Res.Law 61, 64-65 (1975).

"The API clarified the principle in 1942 by saying:

" 'Within reasonable limits, each operator should have an opportunity equal to that afforded other operators to recover the equivalent of the amount of recoverable oil [and gas] underlying his property. The aim should be to prevent reasonably avoidable drainage of oil and gas across property lines that is not offset by counter drainage.' Id. at 65.

"This fair share rule does not do away with the rule of capture, but rather acts to place limits on its proper application.

"Texas has adopted both the ownership-in-place doctrine and the fair share principle. Its courts have addressed the interrelationship between these two principles and the rule of capture.

" 'It must be conceded that under the law of capture, there is no liability for reasonable and legitimate drainage from the common pool. The landowner is privileged to sink as many wells as he desires upon his tract of land and extract therefrom and appropriate all the oil and gas that he may produce, so long as he operates within the spirit and purpose of conservation statutes and orders of the railroad commission. These laws and regulations are designed to afford each owner a reasonable opportunity to produce his proportionate part of ***255** practices injurious to the common reservoir. In this manner, if all operators exercise the same degree of skill and diligence, each owner will recover in most instances his fair share of the oil and gas. This reasonable opportunity to produce his fair share of the oil and gas is the landowner's common-law right

under our theory of absolute ownership of the minerals in place. But from the very nature of this theory, the right of each land holder is qualified and is limited to legitimate operations.' *Elliff v. Texon Drilling Co.*, 146 Tex. 575, 582, 210 S.W.2d 558 (1948).

"The rule of capture is thus modified to exclude operations that are in violation of valid conservation orders.

"Michigan recognizes the fair share principle and its subsequent modifications of the rule of capture. When a adjacent landowner drilled an oil will too close to a property line, the supreme court said that this:

" '[D]eprived plaintiff of the opportunity of claiming and taking the oil that was rightfully hers; and defendants must respond in damages for such conversion.' *Ross v. Damm*, 278 Mich. 388, 396, 270 N.W. 722 (1936).

"The supervisor of wells act also incorporated the fair share principle into § 13. This section concerns proration orders and state in part that:

" 'The rules, regulations, or orders of the supervisor shall, so far as it is practicable to do so, afford the owner of each property in a pool *the opportunity to produce his just and equitable share of oil and gas in the pool*, being an amount, so far as can be practicably determined and obtained without waste, and without reducing the bottom hole pressure materially below the average for the pool, substantially in the proportion that the quantity of the recoverable oil and gas under such property bears to the total recoverable oil and gas in the pool, and for this purpose to use his just and equitable share of the reservoir energy." M.C.L. 319.13; M.S.A. 13.139(13). (Emphasis supplied.)

[5] In the instant case, it is an inescapable conclusion that, until recently, Armand and its predecessors in title did nothing to ensure that the gas under its property was not being drained by other wells known to be producing natural gas from the common pool. It is the failure of these property owners to act, not the operation of the commission's retroactive proration methodology, which resulted in the draining of gas from underneath Parcel B. From the date that the Bowerman-Roy No. 2-10 well commenced production, Armand and its predecessors in title had the ability either to seek an expansion of the 40-acre Bowerman-Roy No. 2-10 drilling unit to include Parcel B or drill a well on Parcel B to ensure that the gas underlying Parcel B would not be drained.

Contrary to Armand's contentions, the order of the supervisor of wells did not find that the Bowerman-Roy No. 2-10 well had efficiently and economically drained gas from under Parcel B since the beginning of production of the well. While it is likely that some of the gas underlying Parcel B was being drained by the Bowerman-Roy No. 2-10 well prior to the expansion of the Bowerman-Roy No. 2-10 drilling unit, it is impossible to ***256** determine the percentage by which each of the wells offsetting Parcel B drained the gas from under it.

The establishment of a DNR drilling unit is not based solely upon the ability of a well to drain gas in a pool. Rather, the size of the drilling unit is determined by the maximum area that may be "efficiently and economically" drained by the well. While the experts testifying in this case agreed that if operated for a long enough period of time, a single well could drain the Washington 10 pool, it does not follow that a single well could efficiently and economically drain the pool. Given the emphasis upon efficient and economic drainage and differences in the costs of drilling wells, is understandable that drilling units may differ in size.

It was originally determined by the supervisor of wells that the maximum area that could be efficiently and economically drained by the Bowerman-Roy No. 2-10 well was limited to Parcel A. Expansion of the Bowerman-Roy No. 2-10 drilling unit from 40 acres to 80 acres was made effective March 15, 1985. Therefore, before that date, the

commission believes that the Bowerman-Roy No. 2-10 well must be considered according to its original designation as a 40-acre unit.

[6] In its fifth exception, Armand contends that the ALJ misinterpreted the significance of its Clarence 19-A example. According to Armand, its reliance upon the Clarence 19-A proration was merely an attempt to demonstrate that its claim for retroactive proration was neither unique nor inconceivable. However, the commission believes that the ALJ was correct in stressing that his selection of a date for the retroactive proration of the Lynn-DeBruyn well by the parties in the Clarence 19-A case was the result of an agreement reached by the parties. This is an important factor distinguishing the Clarence 19-A case from the current contested case. In settlement, parties often accept positions which are otherwise not acceptable in order to gain concessions or avoid the expenses and delays associated with litigation. Frequently, parties specify that positions taken in settlement agreements should have no precedential value in future cases. This allows parties the freedom to resolve disputes without being bound to compromises or positions taken simply to expedite resolution of the dispute. For these reasons, the commission finds that the ALJ properly distinguished the Clarence 19-A case from the instant case.

In its sixth exception, Armand argues that the ALJ erred in finding that its claim would not reduce Mich Con's costs. In his PFD, the ALJ rejected this argument based upon the conclusion that the contract price for the Washington 10 gas would be higher than Mich Con's "average cost of gas." In its reply to exceptions, the staff conceded this statement was incorrect. However, it contended that Mich Con's costs will actually increase by $1.57 per Mcf because the contract price of $3.50 per Mcf would exceed Mich Con's $1.93 per Mcf cost of produced gas (not average cost of gas, as the ALJ said) by that amount. So while the cost to Mich Con of operating the Bowerman-Roy No. 2-10 well should decrease due to payments received from Armand, its gas costs ***257** should increase as it will be paying more for the same gas after the agreement with Armand than it did before it. The net effect of these cost changes is not readily apparent on the record. However, it is certainly likely that any operating savings that will be realized by Mich Con will be entirely offset by higher gas costs. For these reasons, the commission rejects Armand's sixth exception.

In its seventh exception, Armand contends that the ALJ relied upon hearsay to determine that Armand's predecessors in title did not diligently protect their interests from 1980 to 1985. Armand argues that the ALJ considered hearsay evidence regarding reasons why a well was never drilled on Parcel B. The subject first came up during Federated's cross-examination of Mr. Elenbaas:

"Q. Do you have any knowledge as to why that 40 acres wasn't developed for oil and gas purposes?

"A. I have some knowledge. I know, for instance, that Mrs. Roy did not want to have a well drilled on the east of VanDyke where her home was located."

Armand did not object to this testimony. However, Armand did attempt to strike the following question and answer from the testimony of staff witness King:

"Q. Do you know why a well was not drilled on this acreage early in the life of the field?

"A. It is my understanding that the factor which prevented Michigan Consolidated from drilling is that Mr. Bowerman would not sign a lease."

The ALJ denied Armand's motion to strike this testimony on the ground that Mr. King was simply stating the basis for his expert opinion and the fact that it was hearsay did not alone justify its exclusion from the record.

The commission is convinced that the ALJ's determination regarding the diligence, or lack thereof, of Armand and its predecessors in title is accurate.

The fact that Mrs. Bowerman-Roy did not want Parcel B developed was contained in the unobjected to testimony of Armand's own witnesses. Additionally, the commission is unconvinced that Mrs. Bowerman-Roy first had reason to suspect the presence of gas under Parcel B at the time her attorney presented the isopach map from the IRS; the commission believes Mrs. Bowerman-Roy had adequate reason to suspect the presence of gas under Parcel B long before she learned of that isopach map. The presence of offsetting gas wells, including two on her own property, certainly should have raised suspicions of Mrs. Bowerman-Roy of the possibility of gas underneath Parcel B. Additionally, it is undisputed that Mrs. Bowerman-Roy leased a portion of Parcel B to Mich Con in 1980. Given these facts and circumstances, the commission finds that the ALJ properly discounted Armand's argument that both Armand and its predecessors in title had been diligent in protecting their rights to the gas under Parcel B.

[7] In its eighth exception, Armand contends that the ALJ should have found that the relief it requested is fair and would not disrupt the proration system. The commission disagrees. According to staff witness Woodruff, the commission's retroactive ***258** proration system was never designed nor intended to deal with the situation presented by this case. Mr. Woodruff believed that granting Armand the relief it requested would lead to an abuse of the retroactive proration system and might well lead to its abandonment. According to Mr. Woodruff, the staff's longstanding position is that a producing unit should be allowed to produce its fair and equitable share of the *remaining* recoverable natural gas reserves in the common pool *once the capability exists to produce the gas and/or to receive revenues* from the production of gas.

Until Armand signed its agreement with Mich Con for the voluntary pooling and operation of the Bowerman-Roy No. 2-10 well and an application for a revised standard well connection permit was filed with the commission, Armand did not have the capability to produce gas or to receive revenues. However, Armand seeks to be treated as if it possessed the requisite capability as of the filing of the original application for a standard well connection permit for the Bowerman-Roy No. 2-10 well in 1980. If successful, Armand would become entitled to a share of the recoverable natural gas remaining in the pool as of December 1, 1980, notwithstanding that it did nothing to obtain the capability either to produce the gas or to receive revenues from the production of the gas until 1985. Acceptance of Armand's position will not only allow Armand to prospectively share in the production of gas from the Washington 10 reservoir, but will also effectively credit gas already produced by others to Armand and require Armand's alleged deficit to be made up by giving Armand a larger share of future production. Adopting Armand's position would require changing the field rating percentage for the Bowerman-Roy No. 2-10 well from 12.74% to 16.95%, with corresponding reductions to the field rating percentages of all other wells, years before Armand took any action to protect itself from drainage by the other wells. Given these facts, the commission finds that it must reject Armand's eighth exception.

VI.

Proposed Findings of Fact

Pursuant to § 5 of the A.P.A., Armand submitted 14 proposed findings of fact. These proposed findings of fact, and the commission's responses thereto, are as follows:

”1. The application for well connection permit for the Bowerman-Roy No. 2-10 well was filed with the Michigan Public Service Commission on November 24, 1980.”

This fact is true for the original 40-acre unit. On or about May 21, 1985, the commission received a revised application for standard well connection permit covering the enlarged 80-acre unit.

”2. The Bowerman-Roy No. 2-10 well has, since

production from the well began, efficiently drained natural gas from beneath 80 acres of land."

This fact is not true. The establishment of the Bowerman-Roy No. 2-10 drilling unit as a 40-acre unit from December, 1980, through March 15, 1985, also supports the conclusion that the Bowerman-Roy No. 2-10 well ***259** " efficiently and economically" drained only the 40-acre unit referred to as Parcel A. Subsequently, the DNR supervisor of wells determined that, effective March 15, 1985, the Bowerman-Roy No. 2-10 drilling unit should be expanded to an 80-acre unit and as of that date it may be concluded that the Bowerman-Roy No. 2-10 well efficiently and economically drained the enlarged 80-acre unit.

"3. From December 1, 1980, to June 1, 1985, natural gas was drained from beneath the entire 80-acre parcel on which the Bowerman-Roy No. 2-10 well is located by that well and by other wells in the Washington 10 field."

This fact is true for the portion of the 80-acre parcel that is underlain by the Washington 10 field.

"4. Drilling a second well on the 80-acre parcel on which the Bowerman-Roy No. 2-10 well is located would constitute waste."

Under the present circumstances, the commission finds that this fact is true. However, the commission does not agree with Armand's insinuation that this fact was always true.

"5. Pursuant to an order issued under 1939 P.A. 61, the DNR supervisor of wells has determined that the Bowerman-Roy No. 2-10 well has efficiently drained and is efficiently draining natural gas from beneath an 80-acre parcel of land."

This fact is not true, as the order of the DNR supervisor of wells made no finding regarding the ability of the Bowerman-Roy No. 2-10 well to "efficiently or economically" drain the expanded 80-acre unit prior to the effective date of March 15, 1985.

"6. Pursuant to an order issued under 1939 P.A. 61, the DNR-supervisor of wells has determined that the drilling of the second well on the 80-acre parcel on which the Bowerman-Roy No. 2-10 well is located would be unnecessary and would thereby constitute waste."

This statement is true to the extent that it applies to the drilling of a well subsequent to the effective date of the order of the DNR supervisor of wells.

"7. Pursuant to an order issued under 1939 P.A. 61, the DNR supervisor of wells has determined that the appropriate drilling unit consisting of a developed area throughout the production history of the Bowerman-Roy No. 2-10 well consists of 80 acres and has so designated the subject of the 80-acre parcel as the unit for the Bowerman-Roy No. 2-10 well."

This statement is not true. The order of the DNR supervisor of wells had an effective date of March 15, 1985. At best, it can be concluded that subsequent to that date the appropriate size for the Bowerman-Roy No. 2-10 drilling unit was 80 acres and prior to that date the appropriate size was 40 acres.

The next six proposed findings of fact are:

"8. The unit upon which proration must be based for the Bowerman-Roy No. 2-10 well is the 80-acre unit recognized by the DNR supervisor of wells.

"9. The Bowerman-Roy No. 2-10 80-acre unit constitutes one developed area as long as the Bowerman-***260** Roy No. 2-10 well is capable of producing the economically recoverable gas under the unit.

"10. If the Bowerman-Roy No. 2-10 unit is prorated as an 80-acre unit from December 1, 1980, to June 1, 1985, and as an 80-acre unit thereafter, the commission would not be treating the 80-acre unit as one developed area as long as the Bowerman-Roy No. 2-10 well is capable of producing the economically recoverable gas under the unit.

”11. If the Bowerman-Roy No. 2-10 unit is prorated as a 40-acre unit from December 1, 1980, to June 1, 1985, and as an 80-acre unit thereafter, and if other units are prorated retroactively, the owners of the land comprising the DNR recognized 80-acre Bowerman-Roy No. 2-10 unit will be permanently deprived of the opportunity to produce their just and equitable share of the gas drained from the pool by existing wells, including the Bowerman-Roy No. 2-10 well, for the period from December 1, 1980, to June 1, 1985. Said gas will instead be credited to other units.

”12. There is no statute or duly promulgated rule giving the commission the authority to recognize units for purposes of proration that consist of areas different from those established and recognized by the DNR pursuant to § 13 of 1939 P.A. 61.

”13. There is no statute or duly promulgated rule providing standards by which the commission and its staff may be guided in recognizing units for purposes of proration that consist of areas different from those established and recognized by the DNR pursuant to § 13 of 1939 P.A. 61.”

In each instance, what has been described by Armand as a proposed finding of fact is in reality a legal conclusion based upon acceptance of the positions and policies argued by Armand. Under § 85 of the A.P.A. the commission need not respond to such conclusions of law.

Armand's final proposed finding of fact reads:

”14. The relief requested by Armand in this case is identical to the relief granted to the owners of the Lynn-DeBruyn well in Case No. U-970 (Clarence 19-A).”

The facts of the Clarence 19-A proration are significantly different from the facts of the instant case and do not constitute precedent for the commission's decision. The most notable difference between the Washington 10 case and the Clarence 19-A case is the fact that in the Clarence 19-A case the parties agreed that the drilling unit for the Lynn-DeBruyn well should be increased. Additionally, the lands that were added to the existing unit were under one lease and owned by the same land owner.

The commission finds that:

a. Jurisdiction is pursuant to 1929 P.A. 9, as amended, M.C.L.A. 483.101 et seq.; 1919 P.A. 419, as amended, M.C.L.A. 460.51 et seq.; 1939 P.A. 3, as amended, M.C.L.A. 460.1 et seq.; 1969 P.A. 306, as amended, M.C.L.A. 24.201 et seq.; and the commission's rules of practice and procedure, 1979Administrative Code, R 460.11 et seq.

b. The Washington 10 pool is a Salina-Niagaran natural gas bearing reef-type reservoir located in T4N, ***261** R12E, Washington township, Macomb county, Mich.

c. The commission possesses jurisdiction to prorate natural gas production within the state of Michigan, pursuant to 1929 P.A. 9 and 1939 P.A. 61.

d. The purpose behind proration of natural gas production is to protect correlative rights, to permit a reasonable opportunity to produce recoverable reserves, to provide for equitable purchasing and taking of natural gas from a common source of supply, to ensure that each producer recovers production in proportion to the recoverable gas under his or her land, and to prevent waste.

e. The 100% acre-feet method of proration agreed to by Federated, Mich Con, and the staff should be utilized because its use is supported by the well data available for the Washington 10 pool and it will be the fairest and most equitable method of prorating the Washington 10 pool since it permits the opportunity of each well in the pool to produce the percentage of gas underlying each production unit.

f. The effective date of the enlargement of the Bowerman-Roy No. 2-10 well from a 40-acre unit to an 80-acre unit was March 15, 1985.

g. The application for a standard well connection permit for the Bowerman-Roy No. 2-10 40-acre drilling unit was dated November 24, 1980.

h. The application for a revised standard well connection permit for the enlarged Bowerman-Roy No. 2-10 80-acre drilling unit was May 21, 1985.

i. The Bowerman-Roy No. 2-10 well should be retroactively prorated on the basis of an 40-acre unit from December 1, 1980, through May 31, 1985.

j. The Bowerman-Roy No. 2-10 well should be retroactively prorated on the basis of an 80-acre unit from June 1, 1985.

k. The proration schedule attached as Exh. A [omitted herein] should be adopted.

Therefore, it is ordered that:

A. Proration from the Washington 10 pool shall be by a formula giving 100% weight to the acre-feet of pay underlying each producing unit.

B. The net pay isopach map agreed to by Federated Natural Resources, Inc., Michigan Consolidated Gas Co., and the commission staff is hereby adopted as the official isopach map for the Washington 10 pool.

C. The proration schedule contained in Exh. A shall be issued in accordance with this order.

The commission specifically reserves jurisdiction of the matters herein contained and the authority to issue such further order or orders as the facts and circumstances may require.

Any party desiring to appeal this order must perfect an appeal to the Ingham county circuit court within 30 days after issuance and notice of this order, pursuant to M.C.L.A. 462.26.

END OF DOCUMENT

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to consider the appropriate regulatory response to proposals by various producers of natural gas from Antrim Shale Formation to operate their wells under a vacuum.

Case No. **U-16230**
(e-file/paperless)

_____/

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss
COUNTY OF INGHAM)

Linda S. Andreas, being first duly sworn, deposes and says that on **July 18, 2012** she served a true copy of **The Michigan Public Service Commission Staff's Initial Brief** upon the following parties **VIA E-MAIL** as follows:

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Linda S. Andreas

Subscribed and sworn to before me
this 18th day of July, 2012.

Tina L. Bibbs, Notary Public
State of Michigan, County of Clinton
Acting in the County of Ingham
My Commission Expires: 11-13-2014