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Identification of technical barriers and preferred practices for oil production in the Appalachian Basin

Sandra M. Del Bufalo Paez
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**IDENTIFICATION OF TECHNICAL BARRIERS AND PREFERRED
PRACTICES FOR OIL PRODUCTION IN THE APPALACHIAN BASIN.**

Sandra M. Del Bufalo Páez

**Thesis Submitted to the
College of Engineering and Mineral Resources
At West Virginia University
In partial fulfillment of the requirements
For the degree of**

**Master of Science
In
Petroleum and Natural Gas Engineering**

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**Morgantown, West Virginia
2004**

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Water Handling and Disposal, Waterflooding, Appalachian Basin, Enhanced
Oil Recovery, Reservoir Characterization, Flow Unit, Permeability
Prediction techniques, Paraffin, Corrosion, Reducing Electric Cost.
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ABSTRACT

IDENTIFICATION OF TECHNICAL BARRIERS AND PREFERRED PRACTICES FOR OIL PRODUCTION IN THE APPALACHIAN BASIN.

Sandra M. Del Bufalo Páez

The Appalachian Basin is characterized by great number of stripper wells and marginally producing oilfields that face a number of production problems. The purpose of this study was to identify the main problematic issues and preferred solutions for oil production in the Appalachian Basin. Investigation and identification of oil production problems and preferred solutions began with searches in the Society of Petroleum Engineer (SPE) library, and Petroleum Technology Transfer Council (PTTC) website. In addition, journals, workshop, conference were used to find additional information. Formal interviews were arranged with oil producers to gain more insight into problems in the Appalachian Basin. Accordingly, the following production problems were identified and ranked in order of decreasing importance: water production, poor understanding of reservoir heterogeneity, limited availability of compatible water for water injection, lack of sufficient reservoir data such as permeability, porosity, and primary production data for reservoir characterization, and paraffin and asphaltene causing operational issues. The technologies that are investigated included: water controls treatment, water-handling methods, and reservoir characterization using Artificial Neural Networks, paraffin and asphaltene control. In addition, corrosion problems and electrical cost reduction are discussed.

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CHAPTER 1

INTRODUCTION

Demand for oil in the United States has continued to increase to a point that more than half of domestic needs are met through imports. This is a trend that most predict will continue in the near future. One major obstacle to attempt to stem this tide through domestic production is the fact that the recovery from the wells in the United States is inefficient, resulting in vast amounts of oil remaining in the ground. For every barrel of crude oil produced in the United States, two barrels are left in the ground. Average oil recovery from U.S. reservoirs is only about 32 percent. Although it is physically impossible today to recover all of the oil that is discovered, the potential for improvement with the use of technology is significant indeed ^{1*}.

Most oil discoveries in the Eastern United States are found in three distinct geologic provinces as shown in Figure 1. One of these provinces is the Appalachian Basin, which is located in mountainous terrain. It is a foreland basin containing Paleozoic sedimentary rocks of Early Cambrian through Early Permian age. The Appalachian Basin Province crosses New York, Eastern Ohio, Eastern Kentucky, Pennsylvania, West Virginia, Western Maryland, Western Virginia, Eastern Tennessee, Northwestern Georgia, and Northeastern Alabama. This province covers an area of about 185,500 square miles ².

The Appalachian Basin was the site of much early oil exploration. In the early and middle 1800's drillers searching for salt found oil by accident. The oil was located in shallow layers bellow the surface. The first successful production was in the Drake well of Titusville, Pennsylvania. This region peaked around 1900 with respect to oil production as a culmination of the first major oil boom in America (As a matter of fact, West Virginia actually led the nation in oil

* The superscript numbers in text refer to references cited at the end.

production for one year, in 1899)³. Although the Appalachian Basin is where the domestic oil industry began, this region may be characterized by having extremely inefficient production operations resulting in low recovery rates of oil.

Figure 1. Location of the Appalachian Basin⁴.

Nowadays, the Appalachian Basin region is characterized by having a great number of stripper wells and marginally producing oilfields. A stripper oil well is defined as a well in the final stages of production, which usually produces less than 10 barrels a day⁵. There are numerous causes that restrict oil production in the Appalachian Basin. Some of these are water production, poor understanding of reservoir heterogeneity, limited availability of compatible water for water injection, lack of sufficient reservoir data such as permeability, porosity, and primary production data for reservoir characterization, and paraffin and asphaltene causing operational issues⁶.

As a result, it is common for stripper wells to be abandoned, leaving significant amounts of recoverable oil in place. Excessive water production is one of the main problems in this area. Water disposal must be addressed in order to minimize environmental impact, which results in high handling costs for the producers. One of the reasons for the decline of the total field production rate is the fact that the pressure in the reservoir decreases while fluids are withdrawn in the course of production. Therefore, there are secondary recovery techniques that are used to maintain the pressure in the reservoir and improve oil recovery.

Waterflooding is one type of secondary recovery technique that is used in the Appalachian Basin. This technique has been successfully applied in some of the reservoirs found in this region. However, other reservoirs have experienced accidental waterflooding as a result of casing leaks, producing abnormal production of water from the wells. Also, waterfloods have failed as a result of severe uncertainty in oil fields drilled prior to the time of reliable logging tools or production data were available. Poor understanding of reservoir heterogeneity and distribution of porosity and permeability have been a problem that affects the waterflooding process. In addition, limited availability of compatible water for water injection may cause excessive costs for the producers. The water supply should, ideally, be closely similar in character to the formation water. Finally, paraffin and asphaltenes cause reservoir and equipment damage, decrease production and flow rate. The treatments used to remove these components from the reservoir add additional cost to oil production.

There are numerous technologies available to enhance production and reduce operating costs for stripper wells. However most of the fields in the Appalachian Basin are relatively shallow, with low pressure, and heterogeneous thin zones having low permeability. As a consequence, certain enhanced oil recovery techniques are not applicable in this region. Therefore, it is important to assess different characteristics of the reservoir and to try to identify the technologies that are applicable to reservoirs in the region.

The oil industry in the Appalachian Basin is primarily composed of independent small producers that operate stripper wells. The thin profit margins associated with these wells make them extremely sensitive to increases in operating costs or decreases in prices paid for their commodity. Local producers would be unlikely to invest in such fields due to afore mentioned reasons.

The purpose of this study is to gather, discuss and establish a set of possible solutions to the most relevant oil production problems in the Appalachian Basin. This information could be used by the producers to improve

production, increase oil recovery, and at the same time reduce operating costs while increasing the profit margins.

CHAPTER 2

METHODOLOGY

The methodology used in this work consisted of the following steps:

1. Establishing problems and problematic issues related to oil production in the Appalachian region.
2. Identifying potential production practices that can overcome the existing problems.
3. Selection of the relevant technologies.

2.1 Establishing Problems and Problematic Issues Related to Oil Production in the Appalachian Region:

Some of the problems associated oil production in Appalachian has been identified through. The previously held workshops sponsored by PTTC in the region. Attempts were also made during technical meetings such as the SPE Eastern Regional Conference, AAPG Eastern Section Conference, and Stripper Well Consortium Meeting. To engage industry participants in informal discussions regarding the problems that industry is facing in the basin. In addition, the technical presentation during the meeting that provided potential solutions to some of the problems was noted. Formal interviews, though limited, provided another source for identification of problems and best practices.

2.2 Identifying Potential Production Practices that can Overcome the Existing Problems:

The main approach for identifying potential production practices was literature and web searches. The literature review was initiated with the Society of Petroleum Engineers (SPE) Electronic Library. The identified problem areas were used as key words to search the extensive library. The identified papers

were then reviewed to determine relevancy and technical content. The papers that provided potentially useful practices were then summarized. Generally, only recent papers (published within the past 5 years) were considered for this purpose. However, some older papers related to activities within the basin were also compiled and reviewed to establish historical activities or reservoir characteristics. During this process several hundred papers were reviewed and sixty-two were abstracted and a comprehensive list was developed.

In addition to the SPE Library, an Internet search was conducted to identify other potential practices. The various PTTC websites (National and Regional) were found to be a major source of information for various problems and practices. Also, the literature review was continued by searching journals such as the Journal of Petroleum Technology (JPT) and The Independent Oil and Gas Association of West Virginia, Inc (IOGA). In addition, some of the literature information was collected by attending workshop conferences on produced water and associated issues and paraffin and asphaltene problems and solutions. Many of the problems faced by Appalachian operators were found to be common to many other basins. As a result, some of the practices found in the literature review can be applicable in the Appalachian basin. The rest of the information collected from various websites and workshops were also compiled and reviewed.

2.3 Selection of the Relevant Technologies:

The collected information was utilized to identify production practices that are applicable to Appalachian Basin.

CHAPTER 3

RESULTS

Based on the results of interviews and other available information, the following problems were established as the major problem faced by oil industry in the Appalachian Basin ⁶:

Problems

- Water production.
- Poor understanding of reservoir heterogeneity.
- Limited availability of compatible water for water injection.
- Lack of sufficient reservoir data such as permeability, porosity, and primary production data for reservoir characterization.
- Paraffin and asphaltene causing operational issues.
- Enhanced oil recovery.

Solutions

1. Several technologies for water control and shut-off were identified and summarized.
2. Innovative methodologies for reservoir characterization to understand heterogeneity and predict permeability were identified and compiled.
3. Several treatments to solve Paraffin and Asphaltenes were identified and compiled.

The problems highlighted above and the production practices to overcome them will be discussed in the following chapters.

CHAPTER 4

WATER PRODUCTION PROBLEMS AND SOLUTIONS

4.1 Description of the Problem:

Water production is one of the major problems associated with oil production. Usually excessive production of water is the main criterion to abandon oil wells, leaving large volumes of oil behind. Most oil fields experience a gradual increase in water production. Worldwide daily water production is estimated to be some 3 times that of the world oil production ⁶. The source of water is either the formation water or the water injected for improved recovery. The increase in water production is caused by higher mobility of water relative to oil. The higher mobility of water is the results of lower water viscosity and can be further exacerbated by formation heterogeneities leading to water channeling particularly during waterflooding.

Water production can cause severe problems including corrosion of tubulars, fines migration, and hydrostatic loading. The environmental impact of the handling, treating and disposing of the water is a major problem for many operators. The profitability of oil production can be seriously affected by water production and disposal. The increase in oil recovery cost due to increase in operating costs and costs for replacement, and expansion of existing water handling facilities are some of the issues that need to be addressed.

4.2 Produced Water Management Strategy:

Management of produced water is a challenge for mature fields and for the development of remote fields. Effective measures to handle unwanted or excess produced water depend on the asset maturity, on the type of reservoir, production rates, location, legislation and history. The life cycle of water should

always be assessed as part of the reservoir management strategy, considering drilling, completion and production ⁷.

Water production is an inevitable consequence of oil production. However, it is desirable to defer the onset of water production or its increase for as long as possible. Thus the water management strategy main objective is to diagnose the cause of water production, to minimize the production of water implementing remedial treatment, to reduce the costs of traditional water treatment methods and to seek opportunities enabling larger gross volumes to be handled by existing facilities and mitigate the impact on the environment.

4.3 Causes of Water Production:

The water production causes can be divided into several categories including:

Mechanical Problems: Casing leaks are example of mechanical problems. Much excess of water problems is caused by poor mechanical integrity of the casing. Some of the factors that produce casing leaks are holes caused by corrosion, excessive pressure, or formation deformation that can allow unwanted water production to enter the casing ^{8,9,10}. Casing leak are normally detected by an unexpected increase in water production. To evaluate and monitor casing condition, different types of logging tools can be used ¹¹:

- 1) Mechanical (multi-arm caliper): provide information about internal casing condition only.
- 2) Electromagnetic (phase shift and eddy current/flux leakage): electromagnetic phase-shift devices measure the attenuation and phase-shift of a transmitted electromagnetic signal to determine circumferential averages of casing thickness and diameter. Electromagnetic Flux leakage is one of the most acceptable methods for evaluating metal loss.

- 3) Ultrasonic (pulsed echo and acoustic imaging): These are used for casing inspection.

Completion: The common completion related problems are channel behind casing, perforating into or too close to water zone, and fracturing out of zone.

Channel behind casing: This type of problem generally occurs immediately after the well is completed or stimulated. Unexpected water production at this time is an indicator that a channel exists by which permit-unwanted fluid enters behind the pipe ⁸. Temperature surveys, noise surveys, radioactive tracer surveys, mechanical flow meter surveys, and fluid density or capacitance surveys are all used for flow diagnosis and allocation ^{9, 11}. These logs are run to determine if a production problem, such as excessive water, is the result of a completion problem, or a reservoir problem.

Fractures: Natural fractures or induced fractures in a reservoir, sometimes, can cause an excess of water production. One of the reasons for excessive water production is because this water can come from an aquifer via the fractures.

Reservoir: The main reservoir related problems are reservoir heterogeneity such as fracture and high permeability streaks, bottom water coning, and reservoir depletion.

Water coning is one of the main problems in reservoirs in the Appalachian Basin. It is produced when pressure near the well completion is reduced. As a result, water moves vertically toward the completion. The problem becomes worse when this water phase breaks through into the open set of perforation, moving upwards through a hydrocarbon phase, replacing all or part of the oil production.

4.4 Water Production Problems Associated with Waterflooding:

During the life of a waterflood, the volume of water production tends to increase. This unwanted fluid production in producing wells is a factor that limits the productive life of a well, bringing an excessive cost of operations to many producers. Azari *et al*⁹ describes a methodology for identifying excess water production problems in production and injection wells as follows:

4.4.1 Production Wells.

Production Wells (Early Breakthrough)

If water breakthrough is experienced early in the life of the well the following possible reason should be examined.

- Undesired Production from a Channel Behind Casing
- Perforation into Water or too close to water zone
- Fracturing out of zone

Production Wells (Late Breakthrough)

If water entry is experienced late in the life of the well, the operator can expects the following conditions

- Channel from a water flood or natural water drive
- Bottom Water Coning (Vertical water movement trough a hydrocarbon phase around wellbore)
- Casing Leaks
- Depleted Reservoir

4.4.2 Injection Wells.

The problems in injection wells are related primarily to the injection of fluid into unwanted zones built up with materials that reduce injectivity, inadequate information about the reservoir drainage area, and presence of gas cap and reservoir heterogeneity.

4.5 Water Production Control:

The most critical design issue is to determine the source of the water and the production mechanism. Numerous technologies are available for water shut-off, but the nature of the water production must be known in order to design an effective treatment. One of the reasons for failure in managing the increasing flow of water has been the lack of understanding the source and point of entry of the water into the well.

Once the water production mechanism is understood, the water shut-off treatment strategy can be formulated. This involves the selection of an appropriate technology, design of an effective treatment, formulation of a treatment procedure, and an effective quality control program.

4.6 Problem Identification and Treatment:

In order to obtain the best solution to attack excess water production, it is important to identify where the problems are before using any technique. Chan¹² gave details on using log-log plots of water-oil ratio versus time (based on systematic numerical simulation studies on reservoir water coning and channeling) to classify types of water problems. In addition, the time derivative of water-oil ratio can be used to differentiate whether the well is experiencing water coning, high permeability layer breakthrough, or near wellbore channeling. Figure 2 shows the different plots of water coning and water channeling. There can be discerned three periods of WOR. The early time period, where the WOR curves remain flat showing expected initial production. The second time period shows the rate of WOR increasing relatively slow for water coning and relatively fast for water channeling. Finally, in the third time period, a pseudosteady - state cone is developed. The well mainly produces bottom water and the water cone becomes a high water conductivity channel. The WOR slopes are very close because they are mainly controlled by relative permeability functions. Figure 3 shows the promptly increase of WOR after the injection water breakthrough at the production well. The WOR' curve shows a positive slope for a short period

after water breakthrough, continuing with a negative slope which indicates a cone build up. Then, a last positive slope is shows the completion of the water recycling conductive vertical channel construction. Finally, Figure 4 shows a near wellbore problem, where the WOR rapidly increases and the slope turn almost infinity. The time derivative water-oil-ratio would become an effective methodology to select candidate wells for water control treatment.

Figure 2. Water Coning and Channeling WOR Comparison ¹¹.

Figure 3. WOR and WOR' Derivatives for Thief Layer Water Recycling ¹².

Figure 4. Near Wellbore Water Channeling ¹².

The control of the water-cut for mature oilfields is always a challenging task for field operators. To solve the problem, different technologies have been developed. Seright *et al*⁸ provided the following guidelines for various technology applications. Table 1 shows where these technologies can be applied.

In order to obtain successful solutions, the easiest problems should be attacked first. The easiest problems are included in category “A”. These can be solved by traditional methods that include water shutoff technique. There are mechanical and chemical water shutoff methods. When producers know which zone produces water, they can use mechanical methods to selectively prevent this from occurring in specific zones. When the water-producing zone is not known, or when there are breakthroughs or operating difficulties, chemical methods can be used.

Each problem requires a different approach to find the optimum solution. Therefore, it is important that the problem be correctly identified depend of the causes of water production.

Table1 - Excess Water Production Problems and Treatment Categories ⁸.
(Categories are listed in increasing order of treatment difficulty)

Category	Treatment	Where treatment can be used.
A	"Conventional "	Casing leaks without flow restrictions. Flow behind pipe without flow restrictions Unfractured wells (injectors or producers) with effective barriers to crossflow.
B	Gelants.	Casing leaks with flow restrictions. Flow behind pipe with flow restrictions "Two-dimensional coning" through a hydraulic fracture from an aquifer. Natural fracture system leading to an aquifer.
C	Preformed Gels.	Faults or fractures crossing a deviated or horizontal well. Single fracture causing channeling between wells. Natural fracture system allowing channeling between wells.
D	Gel should not be used	Three-dimensional coning. Cusping. Channeling through strata (no fractures), with crossflow.

4.6.1 Methods to Repair Mechanical Problems

4.6.1.1 Casing leak

The methods used to repair a casing leak without flow restriction, (the leak is occurring through a large aperture breach in the piping and a large flow conduit

behind the leak) involve either cement or mechanical devices ^{8, 10}. On the other hand, to repair a casing leak with flow restrictions (the leak is occurring through a small aperture breach in the piping and small flow conduit behind the leak), conventional methods are not recommended to be used. An adequate method to repair a casing leak with flow restriction is by using gel treatments, which are used to solve problems in category “B” ⁸.

After a casing leak is repaired, it must be checked the plugged back total depth and remove any drilling mud or other debris that may have entered into the wellbore ¹⁰.

Table 2 summarizes the different water shut off materials and methods.

Table 2 - Water Shutoff Materials and Methods ⁸

Chemical & Physical Plugging Agents	Mechanical & Well Techniques
Cement, sand, calcium carbonate	Packers, bridge plugs, patches
Gels, resins	Well abandonment, infill drilling
Foams, emulsions, particulates, precipitates, microorganisms	Pattern flow control
polymer/mobility-control floods	Horizontal wells

4.6.2 Methods to Repair Completion Problems

4.6.2.1 Channel behind pipe

The methods used to repair flow or channel behind the pipe without flow restrictions (the fluid flow is occurring through a large aperture flow conduit behind the pipe) involves cement application ^{8,9,10}. On the other hand, to repair flow or channel behind the pipe with flow restrictions (the flow behind pipe is occurring through a small aperture flow conduit), conventional methods are not recommended to be used ⁸. An adequate method to repair the flow behind pipe with flow restriction is by using gel treatments, which are used to solve problems in category “B” ⁸.

4.6.2.2 Fractures

A gelant treatment should be used to solve problems caused by fractures. When the problem is caused by a fault or fractures crossing a deviated or horizontal well, or fractures which produced channeling between wells, it is necessary to use preformed gel^{8, 9, 10, 13}.

4.6.3 Methods to Repair or Control Reservoir Problems

A number of techniques have been developed for water control into the reservoir. These techniques are described in detail by Azari *et al*⁹ and Di Lullo *et al*^{14, 15}.

- Zone Isolation.
- Permeability Blockers.
- Disproportionate Permeability Reducers (DPR) and/or Selective Permeability Blockers (SPB).
- Relative Permeability Modifiers (RPM).
- Dual Completion

4.6.3.1 Zone Isolation

Zone isolation techniques are often used to isolate water-out zones. It is a form of water shut-off and not water control treatment. These include mechanical methods such as using packers and bridges, plugs and squeeze cement, or gelants. However, other methods exist as The Dual Injection technique, which is considered to be an advanced zone isolation technique. Some practical consideration of dual injection have discussed by S.V. Plahn *et al*¹⁸.

4.6.3.2 Permeability Blockers

These materials plug the pore spaces preventing fluid movement, usually by means of controlled, and delayed chemical reaction that allows deep injection of materials before it reacts to form a three-dimensional gel.

4.6.3.3 DPR and/or SPB

These materials also plug the pore spaces, restricting the fluid movement, but they do not precipitate, swell, or viscosity as much in the presence of oil as they do in a water environment. The net effect is reduction of water relative permeability by a larger factor than that of oil.

4.6.3.4 RPM

These are water-soluble hydrophilic polymer systems that, when hydrated, produce long polymer chains that, in the rock, will loosely occupy the pore space. Because of their hydrophilic properties, they attract water and repel oil and, as net result, they exert a drag force on water flow in pores with minimal effect on oil flow.

4.6.3.5 Coning

To evaluate coning, a reservoir or area study may be necessary to determine the current location of the oil-water contact. To diagnose if water coning is the problem, increasing the production rate will usually increase the percentage of water produced. Also, resistivity and porosity logs (sonic, density, neutron) can be combined to determine the location of water and pay zones which later can be compared to cased hole logs to look for coning in producing reservoirs^{8, 9,10,16,17,19}. Three-dimensional coning is a difficult problem, which can be solved applying a dual completion technique^{8,9,16,17,18,19}. The other processes to eliminate or reduce the water-coning problem are to decrease the production rate to shut in the well for several months (around 2 or 3 months). In addition, cement squeezes and plugback techniques can be used to eliminate or reduce water coning problem, only if the source of water production can be identified and isolated, and if the formation prevents the water from bypassing the treated interval. Cement squeeze and plugback techniques are also applied to solve problems of water cusping and channeling problems^{8, 9,10,16,17}.

4.6.3.1. a. Dual Completion Method

This technique uses dual completion technology with zonal isolation packer to separately produce the water and the oil. The water is produced from the perforation below the oil-water contact, at the same time that oil is produced from perforations at the top of the sand. The method creates a downward pressure difference on oil-water contact and so counters the cone development at the wellbore. A basic completion configuration is shown in Figure 5. This technique is mainly useful in reservoirs with severe water coning, where oil is found over water in clean sands with high vertical communication and no vertical flow barriers. It can reduce or reverse the water coning. Because the water is not mixed with the oil, it can be disposed directly without facilities treatment, thus reducing the overall water-processing requirements before it is disposed. However, some mixing can take place, in which case, this technique does not completely eliminate the problem of contaminated water production but reduces it to, perhaps, some manageable level. This problem can be addressed with better water saturation monitoring where real time monitoring and control could be implemented. The detailed description of this technology and guidelines for proper applications are given by Wojtanowicz^{17,19}. Also, Davis *et al*¹⁶ and Plahn *et al*¹⁸ present some experience from field applications using dual completion method.

Figure 5. Basic Completion Configuration¹⁷.

Wojtanowicz ¹⁷ provided the following guidelines to mitigate the problem of produced water contamination while maximizing oil recovery with this technology.

- Adequate field data and production logs should be run to understand the extent of water saturation transition development over time and the possible current location of oil-water contact.
- A good understanding of field history from start of production and location of original oil-water contact is necessary
- Capillary pressure data from core analysis within the field or correlation fields could be used to derive suitable capillary pressure data from the Leverett J-function correlation for the pre-installation studies.

- In the absence of core data, capillary pressure information could be obtained from electric resistivity log responses using typical capillary profile match 15.
- In the last option, linear approximations from Young's equation could be used to together with information from the production logs.
- To avoid, initial oil breakthrough (initial inverse oil cone), the water sink location should be as deep as the limit of water handling capacity can dictate. The sink should not be installed just below the oil-water contact or in the transition zone where mobile oil can easily flow into the water sink.
- In wells where the transition size is almost the same size as oil zone thickness water production starts almost immediately at the oil zone completion. For such completions, it might be necessary to turn on the water sink for a period to collapse the cone prior to start up oil production.
- Incorporating the dual concept of capillary pressure transition and relative permeability hysteresis effects in modeling of old wells can mitigate the problem of contaminated fluid production in these wells.
- Where water handling and disposal is not restricted as in offshore environments, location of the sink closest to the bottom of the water zone increases the size of the domain for segregated fluid production and accelerates oil recovery.
- Locating the water sink at the oil-water contact or slightly below reduces the amount of water production required to counter cone development. However, it creates the environmental problem of inverse oil cone.

Advantages:

- The application of Dual Completion enables operators to produce uncontaminated water from oil wells.

- The produced water is disposable without treatment or could be re-injected for pressure maintenance.
- This technique may provide a tool to bypass the facilities plant and allow for significantly higher re-circulation of water in the reservoir that will ultimately lead to a higher recovery.

Disadvantages:

- It is not suitable in reservoirs with vertical flow obstacles.
- Although this method separately produces the water and the oil, it does not completely eliminate the problem when water is already contaminated at its source.
- The production of uncontaminated water from oil fields with severe water coning history without adequate pre-installation modeling and planning is not possible.

4.6.4 Produced Water Handling.

The main options for produced water handling are ²⁰:

- Surface disposal
- Subsurface disposal after producing to surface
- Subsurface re-injection for IOR after producing to surface
- Subsurface disposal after downhole separation
- Subsurface re-injection for IOR after downhole separation
- Downhole water shut-off

4.6.5 Water Separation and Disposal

Traditional methods for water disposal range from disposal in evaporation and infiltration pools to injection in water disposal wells or injection wells for secondary recovery. The water handling results in significant capital and operational expenditures. Capital expenditure normally means the installation of artificial lift facilities and water treating equipment and/or injection wells. There

are techniques that have shown significant promise to control the cost of water separation and disposal. They include downhole oil/water separation system (DOWS).

4.6.5.1 Downhole Oil/Water Separation System (DOWS)

The system separates water from oil and re-injects it within the same wellbore reducing amount of water that goes to the surface. The system only can be used in wells which have a depleted horizon, with low static pressure that are more probable to need water injection. Figure 6 describes ESP-DOWS equipment.

Downhole separation and disposal in the same well is an environmentally friendly tool that provides a unique opportunity to reduce operating costs and enhance the economic viability of higher water-cut wells (>65%). DOWS (Downhole Oil/Water Separation System) and their application have been discussed by Scaramuzza *et al*²¹ and Blanco and Davies²². The DOWS consist of a hydrocyclone separator couple to a conventional pumping system. This device uses a huge centrifugal force to separate fluids. The concentric reducing of the hydrocyclone and the fine taper accelerate the fluid. Once it is accelerated, the heavy fluid is forced to the walls of liner, while at the same time, the lighter fluid is conducted to the center of the liner where it is collected and goes to a reject point. Figure 7 gives a pictorial view of the hydrocyclone and the flow pattern in it.

Figure 6. ESP DOWS Scheme ²¹.

Figure 7. Flow through the Hydrocyclone ²¹.

Scaramuzza *et al* listed the following advantages and limitations with DOWS.

*Advantages*²¹

1. Operating Costs Reduction

- Lower energy costs due to less lifting, treatment and re-injection
- Lower chemical costs
- Lower treatment costs

2. Capital expenditure Reduction

- Less installations
- Fewer Injection wells drilled

3. Increase of oil recovery because of the

- Lower economic limit
- Improvement of the waterflood

4. Environmental risks and damage reduction

- Lower fluid disposal on the surface.
- Lower risk to shallow fresh water sands
- Reduction of the impact of the environmental regulations.

*Limitations*²¹

- Hydrocyclone hydraulic capacity.
- Min. casing 5^{1/2"}, hydrocyclone 4^{1/2"}, and two tubes up to 720 m³/day.
- Max. Casing 9^{5/8"}, hydrocyclone 7^{5/8"}, 10 tubes up to 4000 m³/day.
- ESP (electrical submersible pump)-DOWS the engine must be installed below the productive zone to allow its refrigeration; otherwise, an engine sleeve must be used when the casing size allows it.

- The presence of sand in the produced fluid could fill the casing below the isolation packer set and plug the water injection perforations.
- The WOR (water oil ratio) must be higher than $5\text{m}^3/\text{m}^3$
- Oil density must be higher than 16° API
- A minimum of difference of 0.05 between specific gravities oil and water is required.
- Oil (typically between 10 and 200 ppm) in the injected water can damage the formation especially those that do not have oil residual saturation.
- It is impossible to effectively stimulate the zones below the pump without pulling.
- Pump deficiency causes discontinuous injection.
- Potential for introducing the scale and emulsion problems is possible due to oil and water phase mixing in the wellbore.

4.6.6 How to prevent the most common problems related to injection wells

The following are the main sources of information to help prevent the most common problems related to injection wells.

- Records of injection pressures and rates.
- Injection Profiles (Spinner survey tool to obtain injection vs. depth data).
- Tracer Surveys for interwell communication (Tracer surveys in multi-well injection-production patterns may be utilized).
- Interference Pulse Testing (time, flow rate and pressure data are analyzed using pressure transient techniques).
- Debris, scale or presence of bacteria (water analysis comparison between injection and reservoir fluid).
- Location of Faults (well testing – buildup and interference test for boundaries detection).

- Injection out of Zone (Rocks mechanics and reservoir data analysis).
- Cross-flow (high volume water flow through an annulus) occurred as a result of fractures, channels, or high or low-pressure layers. Production logging (spinner survey, pressure records, density and temperatures logs) and well testing can be used to identify cross-flow.

It is important to locate high and low extremes of permeability in the reservoir because these are the main conduits for the flow of oil, and, a potential barrier to cross-flow, respectively.

In waterflooding operations, three of the most serious problems are formation plugging, non-uniform injection profile, and injection of water out of the target zone or completion interval.

Recently, some techniques have been presented to control those problems that use thermal neutron capture cross-section logging, new flow meters for production logging and well testing, and gamma-ray-emitting tracers for profile surveillance. In addition to the various testing and logging methods, multiple-well testing provides a means for determining formation continuity between injection and production wells.

4.7 Application in the Appalachian Basin:

In order to obtain the best solution to attack excess water production in the Appalachian Basin, producers must identify the type of water problems and where the problems are, before implement any technique. Therefore, a diagnostic plot methodology, using log-log plot of water oil ratio vs. time and log-log plot time derivative of water oil ratio vs. time, provide the producers with a tool to identify the source of the problem and to select candidate wells for water control treatment. Water controls treatments vary depend on the source of water problems (mechanical, completion, and reservoir). Beginning with the easiest

problems to the complex problems, the treatment for controlling excess of water production in the Appalachian Basin could be applied.

The water handling plays an important role in the cost of water separation and disposal. ESP-DOWS technique is an effective technology to minimize the economic and environmental consequence of water production. It might not be applicable to all the producing wells in the Appalachian Basin. The most important limitation is the size of the hole. Other limitations mentioned earlier in this chapter, also impact the applicability of this technique in a particular well. It needs to be evaluated on a case-by-case basis.

CHAPTER 5

SECONDARY RECOVERY

5.1 Description of the Problem:

Waterflood techniques in the Appalachian Basin have experienced a number of problems including low injectivity, drastic permeability variations, poor completion practices, failure to bank oil, and unfavorable economics. These factors are not independent; the economic factor, for example, is strongly related to injectivity. Another common problem is accidental dump flooding presumably through and around leaking casings of old improperly abandoned wells. The detection of accidental floods is difficult. The best indicator is abnormal production water from the wells. In many cases it is recommended to conduct a pilot flood in order to rule out the possibility of prior accidental flooding.

Some examples of successful Waterflooding used in the Appalachian Basin floods have been seen. These include Cabin Creek Field, Granny Creek Field, and Jacksonburg-Stringtown Field. The results of repressurizing these fields by water injection suggest that a properly engineered waterflood can be successful in the Appalachian Basin, even in reservoirs with high connate water saturation.

Often, during primary recovery, less than 20 percent of the original oil in place is recovered, leaving significant amounts of oil in the ground. In most cases the decline in production is caused in decrease reservoir pressure. Therefore, if this pressure decline could be stopped, the field could continue to produce economically. There are numerous techniques for improving oil recovery and maintaining the pressure in the reservoir. One of the most common techniques for secondary recovery is waterflooding. This technique has been in use since the late nineteenth century.

Before implementing waterflooding techniques in a reservoir, it is important to evaluate preliminary reservoir data and survey all possible water sources. Water will generally need to be treated before it can be injected into the reservoir. It is important to determine what type of treatment is required to make the water suitable for injection. In addition, it is important to make an economic evaluation of the water injection process. After waterflooding is applied, it must be controlled to obtain the best results in oil recovery and profitability. A surveillance program is an essential key to a successful waterflooding project.

5.2 Waterflooding:

Waterflooding is the process of injecting water into an oil reservoir to sweep oil to producing wells. Waterflooding is the most used secondary recovery technique because water is more available than other fluids, it is highly efficient in displacing oil, easy to inject (the most natural place to inject the water is in the lower part of the reservoir, i.e. in the vicinity of the oil-water contact) and inexpensive relative to other fluids.

In waterflooding, certain reservoir and /or well conditions can result in anomalous distribution of injected water, which in turn may result in inefficient flood recovery. Flood pattern, well spacing, and injection pressures should be designed to meet these requirements. If fluid-flow distribution can be ascertained, then corrective measures can be undertaken as needed.

There are different considerations that need to be accounted before implementing waterflooding techniques in a reservoir. The first step is to evaluate preliminary reservoir data including information about water production and gas oil ratio (GOR), and to survey all possible water sources, with special attention given to satisfying quantitative requirements (the pore volume method is a good approximation of the ultimate water requirements for waterflood). It is important to determine what type of treatment is required to make the water suitable for injection, after establishing the source of water. The second step is to analyze

the reservoir data and determine if a waterflooding project will be an attractive candidate to improve oil recovery and profitability.

5.3 Preliminary Reservoir Data:

It is important to gather information on the reservoir before applying a waterflooding project. This is because some waterflooding projects have failed as a result of a lack of information data. Numerous waterflooding project failures have been seen in old fields that lack information because these were drilled before the time of satisfactory logging tools or where reliable production data for the particular zone in question are not available. Therefore, a waterflood in a zone, which has a high primary recovery, meaning an increase in the amount of water produced rather than oil, will result in project failure. Also, connate water saturation has a critical effect on waterflooding recovery. Generally, the risk element involved in waterflooding is much greater where the connate water is high rather than where it is low. Finally, primary recovery of sufficient magnitude to cast serious doubt upon the outcome of a waterflood is not apt to occur as a result of the solution gas drive process alone.

5.3.1 Engineering and Geologic Factors

There are a number of geologic and engineering factors that must be considered before implementing a waterflood^{23, 24,25,26,27}:

- Depth: Impacts the cost of wells (injectors or producers) that must be drilled to develop suitable waterflood patterns.
- Faulting: faults can cause serious problems for waterfloods.
- Fractures: If natural fractures are present, injectors and producers should be installed perpendicular to the fracture strike. This would minimize any channeling effects and lead to a better sweep efficiency.
- Structure: In the case of anticlinal reservoir, water should be injected down dip in order to maximize recovery.

- Porosity: The porosity of a reservoir must be high enough to ensure that there will be a significant amount of oil remaining in-place for economic waterflooding operations.
- Permeability Profile: Uniform permeability is desirable for good sweep efficiency. If the permeability varies substantially, water channeling through the higher permeability portions of the reservoir can become a problem.
- Rock properties: Water wet rocks are usually better candidates for water flooding. Clays can swell and reduce the permeability of the formation.
- Oil Saturation: It is important that the reservoir has a significant amount of oil-in-place to justify a waterflood.
- Water Saturation: Good waterflood candidates should have water saturation of no more than 45%. High connate water saturation results in much higher water relative permeability than oil relative permeability.
- Relative Permeability: For a good waterflood, the relative permeability to oil should be greater than the relative permeability to water at most water saturations. The mobility ratio should be as low as possible, certainly no more than ten and as close to one as possible.
- Crude oil properties: Viscosity of a crude oil is one of the factors that affect the mobility ratio. It is desirable that the oil viscosity is not substantially higher than water viscosity.
- Water Production: The excess water in the reservoir will lead to an inefficient waterflood due to increased relative permeability to water in the zone with higher water saturations.

5.4 Surveying all Possible Water Sources:

It is important to specify the source of water and establish that there is enough water to meet demand. Possible water sources for injection are:

seawater, fresh surface water, produced water or aquifer water that does not come from the producing reservoir.

An incorrect choice of supply water may cause excessive costs for the producers.

The water supply should, ideally, be closely similar in character to the formation water. L.C. Case, M.A.²⁸ describes the proprieties of most significance for trouble-free injection water as follows:

- The water for injection should not be corrosive to the water handling equipment.
- It should not form a scale under the conditions of operation.
- It should not carry inert suspended matter, organic slime, oil, or emulsion in sufficient quantity to clog injection wells.
- It should have calcium and magnesium salts 10% or more of total dissolved solids in the event that any swelling type clays are present in the formation to be flooded.
- It should be oxygen-free and be maintained in this condition in a completely closed system.
- The water supply should be entirely compatible with produced brine if mixed above ground.

A successful water injection scheme can lead to optimum field development by:

- Maximizing overall recovery so that an evenly distributed waterfront sweeps the remaining hydrocarbons towards the producers.
- Accelerating hydrocarbon production by maintaining high reservoir pressure and sweeping oil, rather than water, towards the producers.
- Minimizing water production and associated water handling cost.

- Improving both the environmental and technical profile of the operating company (e.g. by (re) injection of the produced water into the reservoir).

5.5 Type of Treatment to Make the Water Suitable for Injection:

Five components in water detrimental to a waterflood are ¹⁰: 1) microorganisms, 2) dispersed oil, 3) suspended solids, 4) dissolved gases, and 5) dissolved solids. Therefore, these are the principal parameters studied in an analysis of water.

Bacteria are the microorganisms that cause the most serious problem in waterflooding. These may contribute to formation damage or lead to reservoir souring (generation of H_2S) that can cause corrosion problems and loss of injectivity. These can be controlled using biocide chemicals and may be removed by filtration. Another serious problem is the presence of dispersed oil in injection water because oil reduces the relative permeability of water in the injection well. As a consequence, it requires more pressure to inject the same amount of water. Also, scale deposits can adsorb oil and then it is difficult to remove these deposits by acid treatments. Dispersed oil can be controlled by using demulsification chemicals and by better design of the water system.

Also, suspended solids such as clays or living organisms may be problematic. These may reduce injection potential or reservoir permeability and can cause formation plugging. Many suspended solids can be removed by settling tanks and filters.

In addition, dissolved gases such as oxygen, carbon dioxide and hydrogen sulfide, are generally found in injection waters causing corrosion problems and loss of injectivity. Dissolved gas can be removed by degasification. An oxygen scavenger, such as cobalt-catalyzed sodium bisulfite, can remove oxygen. Proper gas blanketing of the water tank also minimizes oxygen entry. Hydrogen sulfide can be oxidized to sulfur with oxygen or sulfur dioxide, or to sulfate with hypochlorite. Removal of carbon dioxide from the water can be achieved by

stripping with an inert gas, such as nitrogen, but the cost generally exceeds the benefit ¹⁰.

Finally, dissolved solids are found in all water. These may produce scaling and plugging effects. It is important to analyze dissolved solids to determine whether precipitates will form under injection conditions or due to mixing with formation waters. Chemical treatment programs and regular water analysis can help to minimize the problems that could cause these precipitates.

5.6 Economic Evaluation of Water Injection:

An economic evaluation of the water injection process plays an important role for the producers. Doing an economic evaluation of water injection could reduce excessive costs. B.Palsson *et al* ²⁹, describe a holistic approach for an economic evaluation of the water injection process, integrating key technical and economical elements, Tables 2 and 3.

5.7 Controlling Waterflooding Process:

A surveillance program is an essential key to a successful waterflooding project. Three major categories of field conditions must be included in any waterflood surveillance program: reservoir conditions, injection/production well conditions, and facilities/ operating conditions. Facilities and operations change considerably depending upon location and these changes continue over the course of the waterflooding process, management of an operation runs into difficulties resulting from injection-pattern, configurations, surface topography, reservoir characteristics, deviated wells and other field operating constraints. Although there are four types of wells that necessitate surveillance (production, injection, water supply, and water disposal wells), the most attention must be paid to production and injection ³⁰.

Table 3 - A Summary of the Economical Elements of Water Injection, as Related to either Injector or Producer²³.

	INJECTION WELL	PRODUCTION WELL
COST	<p>Cost of injection well; design, drilling, completion and possibly modification of platform.</p> <p>Cost of equipment for water treatment and pumping and platform capacity.</p> <p>Cost of injection operations; pumping, chemicals, plant maintenance and monitoring.</p> <p>Cost of workovers, such as tubing replacement, acid, fracturing etc.</p>	<p>Cost of water production; lifting produced water and handling at surface.</p> <p>Cost of produced water disposal.</p> <p>Cost of water related workovers, water shut off and chemical treatment, eg. scale prevention.</p> <p>Possible "loss" of bypassed oil.</p>
BENEFIT	<p>If produced water Injection, then reduced costs due to surface, or other disposal options.</p>	<p>Accelerated production</p> <p>Improved overall oil recovery.</p>

Table 4 - The Advantages and Disadvantages of Different Completion Options for Injectors in a Layered Formation ²³.

COMPLETION	ADVANTAGES	DISADVANTAGES
Vertical or deviated well, open hole completion.	Low cost option. All layers can be reached and minimum flow restriction through the completion.	The tighter layers are likely to plug up quickly. The water will flow into and cool the higher permeability layers, resulting in thermally induced fractures. Then, the fracture will dominate the injection
Vertical or deviated well, selective perforation or chemical conformance control.	Ensures that water enters the tighter zones and sweeps at least close to the injection wells.	Completion will cause flow restriction. The water is likely to flow through the higher permeability zones through cross-flow, deeper in the reservoir.
Horizontal injector, drilled through the tighter zone only.	Maximum control of injection profile.	Expensive and complex well option, both for construction and operation. Contacts only limited number of layers.
“Controlled” waterflood (thermally) fracturing	Selected layers fractured before injection starts into the higher permeability layers, to ensure good injectivity and better profile.	Fracture conformance to the reservoir zone is essential, demanding on extensive monitoring program and study of rock mechanical properties.

5.8 Reservoir Characterization:

One of the major difficulties in predicting performance of waterflood operation is lack of detail reservoir description. Accurate reservoir characterization is the key for predicting the success of secondary recovery operation. Most reservoirs to Appalachian Basin show some degree of heterogeneity due to contrasting lithologies, diagenesis, or sedimentological complexity. Heterogeneity in a hydrocarbon reservoir is referred to as non-uniform, non-linear spatial distribution of rock properties ³¹. Reservoir characterization plays an important role in developing and understanding a hydrocarbon reservoir. This process permits a definition of petrophysical parameters such as rock and fluid properties (porosity, permeability oil, gas and water saturation), the flow units and the reservoir production mechanisms to understand and unlock the full reserve potential of a reservoir.

Reservoir characterization along with a realistic flow unit model is the basis to successfully simulate a secondary recovery performance by predicting or interpreting fluid displacement behavior. A flow unit is defined as a zone that is continuous over a defined volume of the reservoir, with similar average rock properties, and geological and petrophysical characteristics, which affect fluid flow ³². These properties are internally consistent and predictable through the zone and differ from properties of other reservoir volume. Slatt and Hopkins concluded that the flow unit model provided one of the most complete reservoir descriptions since the flow unit model allowed for the interpretation of many of the geological and petrophysical properties into the reservoir description, which leads to improved recovery and reservoir management ³³.

Independent operators can take advantage of improving oil recovery, increasing their profitability and reducing costs by using reservoir characterization technologies. Also, they will understand the heterogeneity of the reservoir, which will improve placement of the wells.

5.8.1 Reservoir Characterization Studies in the Appalachian Basin

A number of studies have been performed in the Appalachian Basin, which has led to the development of new technologies for reservoir characterization. The reservoir characterization studies that were performed on Granny Creek and Jacksonburg-Stringtown Fields are received here:

5.8.1.1 Background of the Granny Creek Field

Granny Creek field, located in Southern West Virginia (Figure 8), was discovered in 1924. It is located structurally on the northwest flank of a syncline, which strikes N 15-20 degrees east to S 15-20 degrees west. The crude oil in Granny Creek is a paraffin base, Pennsylvania grade oil with a viscosity of 3.14 cp at atmospheric pressure and 75 °F and a liquid gravity of 45.4° API at 60° F. The total oil production is around 6,500,000 and 6,750,000 barrels. Granny Creek field is a shallow oil reservoir with about 1800-2000 deep feet of producing horizon. The producing horizon in this field is the Upper Pocono Big Injun sand of Lower Mississippian age. Big Injun sandstone in this field has a net thickness about 35 to 45 feet and is capped by Big Lime. Pocono Big Injun is subdivided into three members (A, B, and C), at the same time the member C is subdivided in three different layers numbered from oldest to youngest (C_1 , C_2 , and C_3). The thickness data and completion records show that C_2 is the major reservoir and producer within the field. The table 4 shows characteristics that correspond to the grain-size distribution and bulk density variations^{34, 35}.

Waterflooding was initiated in the 1970's and currently is in progress as a series of five spot patterns^{34, 35}.

Figure 8. Location of the Granny Creek Field ³⁴

Table 5. Characteristics of Grain-Size Distribution and Bulk Density Variations³⁵

Lithofacies	How Identified	Member	Thickness (ft)	Bulk density variation	Average Permeability (md)
Upper coarse-grained sandstone and conglomerate (low density)	Gamma and density logs.	A	5-15	Low density	Good
Coarse-grained sandstone and conglomerate (high density)	Gamma and density logs.	B	5-10	High density	Poor
Fine-grained sandstone	Gamma and density logs.	C3 C2 C1	20-35	Low density	Good

5.8.1.3 Background of the Jacksonburg-Stringtown Field

The Stringtown field was discovered in 1895. The field is located on the western flank of the Burchfield syncline, in southeastern Wetzel, eastern Tyler, and northwestern Doddridge counties, West Virginia (Figure 9). The crude oil in Stringtown has a viscosity of 3.5 cp at atmospheric pressure and 75 °F, a liquid gravity of 44° API at 60° F. The range of pay thickness varies from 4 to 20 ft. The variation is due to the depositional characteristics of the environment. The range of permeability varies from less than 5 md to more than 250 md. Total oil production is estimated to be some 13 millions barrels to date and the initial oil in place was estimated at 88.5 million barrel. The primary producing formation in the field is the Upper Devonian Gordon Sandstone. The Gordon embraces five different lithofacies stacked into three parasequences. General characteristics of each lithofacies are show in table 5. Only one of the lithofacies (Fss) display characteristics of pay³⁶.

Figure 9. Location of the Jacksonburg-Stringtown Field³⁶

Table 6. Lithofacies Characteristics ³⁶

Lithofacies	How Identified	Symbol	Thickness (ft)	Grain size	Average Permeability (mD)
Shale	Core and Log	Sh	1-20	clay/silt	2.81
Heterolithic bioturbated	Core and Log	Hb	1-5	clay to sand	0.18
Laminated sandstone	Core and Log	Lss	5-15	fine sand	3.48
Conglomeratic sandstone	Core	Css	5-8	fine sand to granule	3.84
"Featureless" sandstone	Core and Log	Fss	1-10	fine sand	41.29

The pilot waterflood of the Gordon was installed in 1981, as an approximately 34-acre dual five-spot. An average of 1300 BOPA was recovered in 4 years. Water injection rates were limited due to supply. Lower than predicted (1500 BOPA) recovery is believed to be due to dump flooding of the eastern five-spot (Boone and others).

The full-scale waterflood began in 1990. Since 1990, more than 100 new wells have been drilled for water injection and 40 new wells drilled for production. Of these newly drilled wells, 24 of them have been drilled with low angle deviations, to accommodate surface topographic and logistical constraints. Penn Energy, the operator at the time, divided the field into 3 areas or units for waterflood development. Unit I, consisting of 1,815 acres, was formed in 1981, and contains the pilot waterflood. Unit II, 5,723 acres, was formed in 1986 and is located north of and adjacent to Unit I. Unit III, 1,360 acres, was formed in 1995 and is located south of Unit I ³⁶.

From January 1991 through February, 1999 1,864,782 barrels of oil have been produced as a result of the full-scale waterflood ³⁶.

5.8.1.4 Description of the studies developed in the Granny Creek and Jacksonburg-Stringtown fields.

In order to define flow units appropriately, permeability and porosity must be predicted with accuracy. Porosity is generally evaluated using density log data that usually is available for the majority of reservoirs. But permeability values, which are generally determined from core analysis, are not usually available because core analysis is an expensive technique that only can be applied to a few wells.

Owing to the lack of data available in most of the wells to predict permeability distribution, a methodology for reservoir description and characterization utilizing only geophysical well logs and geological information data represents a significant technical as well as economic advantage. Therefore, using graphical, statistical and Artificial Neural Networks to predict permeability from well log data.

Numerical reservoir simulators can solve problems related to geological and petrophysical characteristics in a heterogeneous reservoir. The reservoir simulators can describe quantitatively the flow of multiple phases, and can develop an accurate description of compartments and their distribution.

5.8.1.5 Permeability Prediction in Granny Creek field.

Numerous studies for estimating permeability of a heterogeneous formation utilizing geophysical well logs and geological interpretation have been performed in Granny Creek field ^{34, 35}. The methodology followed in these studies was to divide the formation into zones for studying the permeability variation in each zone as a function of well log data. The purpose of these investigating was to determine a correlation between permeability and log data.

The whole core analysis on seven centrally located wells was used to develop a correlation between permeability, porosity, water saturation, depositional environment, and pore type. Gamma Ray (response are an indication of shalyness or clay content of the formation and may have some

impact on the ability of the rock to conduct fluid), Deep Induction (usually used to calculate water saturation in rocks), and Bulk Density (used to calculate porosity of the rock) logs were collected for all these wells. The results showed that satisfactory correlations could not be developed. It was noted that full diameter core analysis, represent the average rock properties over the interval of the study. The whole core has a tendency to ignore the rapid changes in rock properties that are common to heterogeneous formations. Therefore, to lessen the averaging problem with whole core analysis, two wells, one located on the most eastern part, and the other one located on the most western sides of the field, were selected for detailed plug core analysis. In these two wells Gamma Ray, Induction, Density logs and permeability values were used to compare the similarities between them. Accordingly, three different zones (zone 1, zone transition and zone 2) were defined in term of log responses and annotated as Gamma Ray Induction Density (G.I.D). After, zone 1 and zone 2 were subdivided into 1A, 1B, 2A and 2B. As illustrated in Figure 10 and 11, zone 1A begins with the first cross over of induction and gamma ray log responses and terminates when they cross over again. Zone 1B initiates at this second cross over and terminates at the next cross over of induction and gamma ray responses. The transition zone starts at the last cross over and continues as density and induction log responses follow a decreasing trend while gamma ray response increases and then decreases. Zone 2 A is characterized by relatively constant induction and gamma ray log responses. When the induction and gamma ray log responses begin to diverge zone 2B begins and continues to the end of the core related ³⁵. The obtained results showed that there were similarities among the zones with the exception of the transition zone.

The extension of the early study tried to find the reason for discrepancy in porosity values between the two wells and the other adjacent wells. It was concluded that the matrix density varies significantly in heterogeneous formations from well to well. Hence, a specific matrix density cannot provide accurate prediction for a well that is characterized by a different matrix density. Therefore, the bulk density values had to be adjusted for proper matrix density values to

establish the correlation ^{34, 35}. Then, maps were prepared to correlate the reservoir properties between wells.

Figure 10. Core Plug Permeability and Log Responses for the Eastern Well ³⁵.

Figure 11. Core Plug Permeability and Log Responses for the Western Well ³⁵.

5.8.1.6 Permeability Prediction in the Jacksonburg-Stringtown field.

Graphical^{31, 32,37}and Statistical^{37, 38} approaches were used in Jacksonburg-Stringtown to predict permeability and to divide the formation into flow units.

The primary tool for flow unit identification based on the porosity and permeability relationships in the study of individual wells was the plot of cumulative flow capacity versus cumulative storage capacity (Gunter *et al*) where the deflection points were indicators of flow unit boundaries. Because the permeability was evaluated by core analysis, it was neither sufficient for developing reliable porosity-permeability correlation nor for identifying the flow unit boundaries in some wells (Aminian). Therefore, to pinpoint the flow unit boundaries detailed permeability measurements were required. Hence, core permeability measurement via minipermeameter and porosity values from the well logs was utilized in a similar manner to develop cumulative storage capacity versus cumulative flow capacity graphs³⁷. A semi-log scatter plot of permeability versus porosity and the flow zone indicator (FZI) was used to verify and refine the previously determined Flow Units. To identify the flow unit in the reservoir, it was necessary to use statistical techniques and artificial neural network (ANN) to correlate these units across the wells. Mustafa, R.³⁷ developed a study to find flow unit by using statistical techniques, the Reservoir Zonation technique (Testerman) for identifying, and describing and correlating zones in a reservoir. He used a linear relationship between the log density and core permeability data in the cored wells to predict permeability of the uncored wells. Then, the statistical method was used to identify the Flow Unit, by using core and predicted permeability data. Finally, the Flow Units of each well were correlated to characterize the reservoir. He concluded with this study that the statistical zonation technique could successfully identify flow units in wells with core permeability data. The methodology used was as follows:

Selection of the zone where variation of permeability within the zones is minimized and between the zones is maximized.

$$I_z = 1 - \frac{S_z}{S_{zz}}$$

The largest value of I_z represents the best division into additional zones and continues until the difference between the variance within the zone (S_z) and variance between the zones (S_{zz}) is negligible. These techniques are not very accurate because of the significantly limited data for identifying flow units ³⁷.

5.8.1.7 Permeability estimation using Artificial Neural Networks

Artificial Neural Networks is a technique superior to statistical methods in predicting flow unit and permeability from well log data because of their excellent pattern recognition ability. These systems are physical cellular systems, which can acquire, store, and utilize experiential knowledge ³⁹. It was demonstrated that with a limited number of data, a carefully designed and developed ANN could provide acceptable results.

The key to using ANN is to observe, recognize, and define problems in a way that may be addressable by neural nets. Neural nets do not use an algorithmic process. They respond, like humans, thinking and learning by experience. Therefore it is necessary to expose the net to sufficient examples, so it can learn and adjust its links and connections between different neurons ³⁹.

Neural networks can be programmed to train, store, recognize, and associatively retrieve patterns or data base entries; to solve combinatorial optimization problems; to filter noise from measurement data; and to control ill-defined problems^{37, 40,41}.

Some studies with ANN have been implemented in Granny Creek and Jacksonburg-Stringtown with success.

5.8.1.7.a Study Using ANN in Granny Creek Field

A methodology implemented in Granny Creek was as follows ⁴⁰:

Five wells were taken which have all the necessary data to train the ANN. Then, four separate networks were utilized as follow:

Depositional environments and Lithofacies zones are strictly core-based definitions. Statigraphic zones are log-based definitions and GRID zones are dependent on log and core data.

Input used in the networks:

- Depth (every data point)
- The slope of the log plot (log reading vs. depth) prior and after that point (depth).

Output:

- Zones.

Training:

ANN was provided with the log data (input) as well as the definition of the various zones (output). After a number of iterations, the networks recognized a pattern between the input and output.

Verification:

Two wells were utilized to verify the accuracy of the network prediction. These were compared with zone previously identified from core and log.

5.8.1.7.b Studies Using ANN in Jacksonburg-Stringtown Field

Different studies using ANN were performed in Jacksonburg-Stringtown. Gil, E. ⁴² used six different wells for predicting porosity and permeability using Artificial Neural Network. Random selections of core porosity and well log data were used from five different wells for training ANN. One of the six wells was

used as the verification set. Then, the flow units were selected based on porosity and permeability distribution findings that it enhanced the simulation to evaluate the waterflood performance of the dual five-spot pilot project in the Stringtown oil field. In his work he could conclude that the prediction of porosity and permeability with ANN improved the description of the reservoir and helped to identify the main flow units for the formation in the pilot area. The obtained results revealed that the randomly selected test set might result in accurate predictions if the number of data that are used to train the network is very long. If the data are limited, the random selection is sensitive to the arrangement of the data. Oyerokun, A.⁴³ developed a pre-specified test set approach for training the network when the data are limited, using input from electric log and flow units obtained from geological interpretation of the pay zone. Several methods for identifying the common set test were considered. The first method involved setting an entire well as a test set, whereby four wells are used as training sets and the sixth well is used as the verification set. In the second method, the test set consisted of the minimum and maximum values of permeability in each well. The third method utilized trial and error to define the best possible test set. He concluded in this study that using each of these methods improved prediction permeability in some of the study wells but not in all of them. Also, with this study it was proved that the pre-specified test set generated better results than the randomly selected test when the data are not very long for training the network.

ANN can successfully predict the permeability from log data only when the flow units are provided to the network as input. This interdependency of the flow units and permeability required direct prediction of flow units by ANN using only the well log data as input. To discover the complex relationship among well log data and flow units, the back propagation network was utilized³⁷.

In the absence of the permeability as input the network is not capable to correctly identify the flow unit for transition zone. So, a new set of networks was trained by designating three flow units (unit I, transition zone, and unit II) as

target outputs. Using this set of networks successfully predicted the flow units including the transition zone.

Once the flow units are predicted ANN can be used to predict the flow unit characteristics, mainly permeability. Again in this case back propagation networks were utilized for permeability prediction from the well log data (Aminian, *et al* and Thomas)³⁷.

The predicted permeability values were combined with the flow unit thickness data to determine flow capacity (kh) for each flow unit in each well. The results were utilized to generate field maps showing the distribution of flow capacity for each flow unit.

Flow unit-based modeling can significantly improve the simulation of the waterflood performance in this heterogeneous reservoir. The methodology utilized was as follows:

- Collected well records, well logs.
- Core analysis from several flood patterns was utilized to generate the necessary input for the flow unit and permeability prediction networks.

The results of the network predictions were then utilized to generate the description of the reservoir in these patterns. The reservoir description and injection-production data were then used in conjunction with a reservoir simulator to predict the waterflood performance in these patterns. Alla, V.⁴⁴ developed a study to identify flow units by using BOAST98 software to simulate two adjacent five spot patterns in the Stringtown field. He developed two alternate simulation models in which one model had two layers representing two flow units and the second model had three layers representing three flow units. He concluded in this study that simulation of waterflooding performance could be used with considerable accuracy to verify the flow unit prediction methodology.

It can be concluded with the numerous studies performed in heterogeneous fields that artificial neural networks is a reliable method to predict

data. It is important to confirm that the most important factor in developing an ANN is the input data selection to properly describe a given problem.

5.8.1.8 Using Electrofacies for Permeability and Flow Unit prediction.

The purpose of this study was to find any correlation for predicting flow unit or permeability by using Electrofacies as a guideline. This study was performed by using the data of the four wells in the Jacksonburg-Stringtown field. The methodology and results of this study are discussed below:

The first step was to separate each of the electrofacies and each flow unit in groups depending on their densities and depth. Then, a simple linear regression was used to plot flow unit vs. electrofacies (Figure 12). The results indicated that the flow unit 1 cannot be discriminated using groups of electrofacies 2, 3 and 4. But accordingly to the characteristics of electrofacies 2 and 3, flow unit 1 is mostly related with these. On the other hand, the flow unit 2 is mostly represented by group 4 of electrofacies. After that, a typical linear regression was used to plot log permeability data vs. porosity data and log permeability data vs. log porosity for each electrofacies and each flow unit. The purpose of this was to find a relationship between electrofacies and flow units, but the results indicated that no reliable correlation between them could be found. Figure 13, Figure 14, and Figure 16 can show that there is not any correlation among electrofacies 2 and 3, and flow unit 1. Also, Figure 15 and 17 show that a poor correlation exists between electrofacies 4 and flow unit 2. Therefore, to try to find a correlation between electrofacies and flow unit or permeability, diverse well logs (gamma ray, gamma ray slope, density, density slop) vs. permeability and well logs vs. log permeability were used. At this time, a multiple linear regression (LINEST) was used to find the relationship between the well logs and the core permeability for each group of electrofacies and flow unit. This method calculates the statistics for a line by using the "least squares" method to calculate a straight line that best fits the data, and returns an array that describes the line. The equation for the line is:

$y = mx + b$ or $y = m_1x_1 + m_2x_2 + \dots + b$ (if there are multiple ranges of x-values) where the dependent y-value is a function of the independent x-values. The m-values are coefficients corresponding to each x-value, and b is a constant value. Then, the array that LINEST returns is $\{m_n, m_{n-1} \dots m_1, b\}$, because y, x, and m can be vectors.

Figure 12. Flow Units vs. Electrofacies.

Figure 13. Electrofacies 2

Figure 14. Electrofacies 3

Figure 15. Electrofacies 4

Figure 16. Flow Unit 1 (all wells)

Figure 17. Flow unit 2 (all wells).

5.8.1.9 Using Electrofacies for Permeability prediction in Granny Creek field.

The results from this study can also demonstrate that electrofacies cannot be a guideline to predict permeability in heterogeneous reservoirs as show the figures 18, 19, 20 and 21 in the Granny Creek field.

Figure 18. Electrofacies 1 ⁴⁵.

Figure 19. Electrofacies 2 ⁴⁵.

Figure 20. Electrofacies 3 ⁴⁵.

Figure 21. Electrofacies 4⁴⁵.

5.8.1.10 Application in the Appalachian Basin:

Waterflooding is a technique that could be applied successfully in several fields in the Appalachian Basin. This success of waterflooding is affected by the degree of heterogeneity of the reservoirs. Most reservoirs in the Appalachian Basin are characterized by some degree of heterogeneity. Therefore, it is important to perform a detail reservoir characterization study before undertaking waterflooding operations.

The key parameter for reservoir characterization is the permeability distribution. In reservoirs where permeability measurements are not abundant, permeability must be predicted from well log data. The statistical techniques often fall short of the accuracy needed for permeability prediction. Reservoir characterization studies in the Appalachian Basin indicate that artificial neural networks are superior to statistical methods in predicting permeability from well log data because of their excellent pattern recognition ability.

The rapid changes in properties that are common to heterogeneous formations necessitate detailed permeability profile to accurately identify the flow units in the reservoir. The identification of transition zone plays a key role in success of permeability and flow unit predictions. The detailed permeability profile can be obtained through extensive core plug studies or mini-permeameter measurements. This type of measurements provides a permeability profile that is in similar scale as well log data. Combination of Statistical methods and Neural Networks provided a new and innovative methodology for reservoir characterization in the Appalachian Basin. Also, the integration of geological interpretation and reservoir simulations studies can be used as instrumental in identifying reservoir heterogeneities.

CHAPTER 6

ENHANCED OIL RECOVERY.

If waterflooding can be successful, then polymer-augmented waterflooding should also be applicable and even more effective. However, this assumes that the injectivity of the wells will not be drastically changed by the polymer solution. Many years of actual field experience in other basins show that this is normally the case but the clay problem and low permeability (below 20 md) can produce disastrous results. The chief advantage of this technique for Appalachian reservoirs is that the chemicals are relatively inexpensive and high pressures are unnecessary. Polymer-augmented waterflooding should be applicable if the reservoir permeability is greater than 20 md ⁴⁶. Polymer flooding has been used in a few waterflooding projects in order to even out the injection front as it passes through varying permeability in a reservoir. Also, this polymer has been used behind micellar slugs to obtain an even advance of the flood front. Several projects using a micellar solution followed by water injection with polymer to control viscosity were used in Pennsylvania with varying results. Some of the projects experienced good oil recovery but costs were excessive and there was no indicated economy in further projects. The process would have a much greater potential success rate in higher permeability rocks because injection rates were low due to a highly viscous micellar slug and low formation permeability. It is concluded based on some work done in which injection rates were low due to a highly viscous micellar slug and low formation permeability.

On the other hand, CO₂ and nitrogen would be used in reservoirs with low permeability ^{46, 47, 48,49,50,51}.

CO₂ -flooding injection is a process that improves oil recovery by swelling the crude oil, reducing the oil viscosity, reducing the gas-oil interfacial tension, vaporizing and extracting the lighter hydrocarbons in crude oil and generating

miscibility by the multiple contact process if the pressure is high enough. Even though CO_2 will not mix with oil when they are first combined, when it is introduced into a reservoir a miscible front forms as small, light hydrocarbon molecules mass from the oil to the CO_2 . This front is basically a mass of enriched gas consisting of the CO_2 and the light hydrocarbons from the oil. Under exact conditions related to pressure and heat, this front will indeed be soluble with the oil, facilitating a move towards production. CO_2 –flooding injection could be applied to reservoirs of high interstitial water saturation or watered-out waterflood reservoirs. Miscible CO_2 flooding is one of the most economical oil recovery processes for recovering additional oil from reservoirs that have been waterflooded. One critical requirement for the CO_2 process is that the reservoir will competently hold miscible pressure. Also, this process includes a restriction to reservoirs greater than 2000 ft deep, with oil gravity greater than 25° API, and high residual oil saturations, generally greater than 20 %. Pressure, which has been depleted, must be restored before applying CO_2 injection.

CO_2 flooding is sensitive to reservoir characteristics. Therefore, it is important to assess the reservoir conditions and choose the best location for injecting CO_2 . Waterflooding with poor sweep efficiencies or large injection losses is not a good candidate for CO_2 flooding injection. Also, the viscosity of carbon dioxide is very low and if natural or induced fracture systems are in close proximity to injection wellbores, a great percentage of the injected CO_2 can be lost. In addition, there are some unfavorable conditions (excessive fractures, thin pay, wide spacing, high minimum miscibility pressure, large gas cap, and thief zones) that could affect the injectivity of the CO_2 .

CO_2 is an enhanced oil recovery process which can be very successful if it is properly applied in specific locations and if it is available at a low price. This process has been applied in the Appalachian Basin but has been sensitive to oil price and the amount of incremental production. However this process could be considered as a viable method of oil recovery in a high water saturation reservoir or in a field that has reached an economic waterflood limitation. Some possible

sources for obtaining a cheap source of CO₂ could be power plants, high CO₂ content natural gas deposits, or manufacturing facilities. Also, operators can reduce the cost of CO₂ by using the Huff and Puff method. It is an enhanced oil recovery method used for increasing light oil production and has been a successful technique in pressure-depleted reservoirs. This process consists of injecting CO₂ into an oil well. Then, the well is shut in for a “soak period”. During this period the CO₂ swells the oil and reduces its viscosity. Finally, the well is opened and placed on production. This process can be repeated several times, but efficiency decreases with the number of cycles.

Nitrogen-CO₂ flooding is a cheaper variation on traditional CO₂ flooding. Nitrogen may typically be produced at the reservoir site, reducing the need for bringing in outside CO₂ by pipeline or ground transportation. Cryogenic separation allows nitrogen to be extracted from the air in any amount necessary, and it is an inert gas that is also non-corrosive.

In Nitrogen-CO₂ flooding, the nitrogen is injected into the reservoir to displace CO₂ slug and its associated oil bank.

CHAPTER 7

PRODUCTION PROBLEMS.

7.1 Paraffin and Asphaltenes

Paraffin related problem appears through out the production process of nearly all kinds of crude oils all over the world. Paraffin deposition is one of the major problems with reservoirs that produce paraffinic oil. Wax is solid-state normal alkane with 15~80 carbon atoms and very few branch chains. Paraffin deposition generally consists of wax, asphaltene, resin and sands etc. The main component is wax. Under the reservoir conditions, the wax is dissolved in the oil. But in the course of oil production the decrease in pressure and temperature and release of the solution gas, the wax is separated out to form crystals. The wax crystals will grow, aggregate and then precipitate.

Deposition of asphaltenes and paraffins causes plugging of production lines, oil tubulars, and formation face in and around the sandface. Paraffins deposition costs oil companies millions of dollars per year removal costs and more in lost production.

Paraffin may be deposited throughout the oil flow system from the reservoir, through wellbore tubulars, to surface facilities and in the refinery. In some field cases, the reported paraffin and asphaltene deposition in reservoirs has been so severe that it significantly reduced well productivity and injectivities. Asphaltene deposition has also occurred in the field when solvents were used to displace oil in Enhanced Oil Recovery (EOR) processes. Acidizing operations are also known to cause asphaltene flocculation and deposition.

The process of wax precipitation includes three stages that include wax separation, wax crystal growth, and the wax deposition. Paraffin inhibition can be achieved by controlling of any one of the three stages of wax deposition. Commonly used electric heating cable is an example of control wax deposition at

the first stage (wax separation). The application of chemical inhibitors is the example of control at the crystal growth stage. The glass oil tube and coating oil tube are the examples of control wax deposition at the third stage.

7.1.1 Treating Methods

Conventional and recent techniques for treatment of paraffin or asphaltene deposition can be categorized into the following main groups^{52, 53,54,55,56}:

7.1.1.1 Chemical Treatment

Chemical methods are the most popular ones for asphaltene treatment since they can be used to treat depositions in wellbore and/or into the producing formations. Chemical treatment falls into three major classes:

a) Solvent treatment: Solvents (such as toluene and xylene) are used generally to dissolve deposits of asphaltene.

b) Asphaltene detergents: detergents are a class of surface-active agents. They are used to break up the asphaltene deposits and also prevent them from re-agglomerating back.

c) Crystal Modifiers: Polymers are used to alter wax crystal growth by disrupting nucleation, crystallization, or modification of the paraffin crystals.

For all types of chemical treatments, there are limits and restrictions on the use of many chemical-treatment materials necessitated by concerns for environmental safety and personal exposure hazards.

7.1.1.2 Mechanical Treatments

Mechanical treatments are used to remove asphaltene deposits from flow lines, producing tubing, and pipelines. These methods include rod scrapers, wire line scrapers, flow line scrapers, and free-floating piston scrapers, for cleaning flow lines and wire lining tubing. The advantage of mechanical methods includes good cleaning with minimal formation damage. The disadvantages are:

a) They are expensive treatments.

b) They are restricted by their nature to production facilities and would not help if asphaltenes are deposited within the producing formation,

c) Their application is limited by availability of equipment involved and time.

d) There is a danger of mechanical parts getting lost in the hole, which necessitates fishing of tools.

7.1.1.3 Thermal Treatments

This category of treating methods includes hot oiling, bottomhole heaters, water, and the use of heat-liberating chemicals.

a) Hot Oiling: describes of the process of injecting hot oil to remove asphaltene deposits from a well. Hot oiling causes formation damage and is not recommended in most cases.

b) Downhole Heaters: The downhole heater represents a continuous source of heat which can be used for a period of time to melt asphaltene or paraffin deposits in the wellbore or on the tubing which are then pumped up to the surface with oil production.

Economics of maintenance, cost of the heating system, and availability of electric power limit this technique.

c) Heat-Liberating Chemicals: This process involves pumping down a mixture with equal molar concentrations of ammonium chloride and sodium nitrate. A buffer is used to delay the exothermic reaction until the fluid reaches the bottom-hole with a large quantity of nitrogen gas. The disadvantages of this method are

(i) It is very expensive in comparison with conventional thermal methods

(ii) The process must be designed and closely monitored by a chemist on location.

7.1.1.4 Microbial Treatment

Microorganisms alter the composition of the oil. Biodegradation generally converts long chain paraffins into short chain paraffins. This will result in lowering of Pour point and Cloud point temperatures. In addition to preventing formation of paraffin and asphaltenes, microbial treatment will reduce oil viscosity and density. This reduction in viscosity enhances oil mobility, which can lead to additional oil recovery. The microbial treatment represents a successful alternative technology to remove paraffin deposits without causing lasting formation damage.

7.2 Corrosion

Very often, corrosion is one of the most severe problems faced by oil producers. Correctly identifying water or other environmental factors containing corrosive components such as hydrogen sulfide (H_2S) and (CO_2), and taking steps to prevent their ill effects is essential for oil producers. Corrosion is defined as the destruction or deterioration of a material because of a reaction with its environment. This process may take place at anytime in the oil production. It can happen either below or above ground; it can also affect equipment and even processing and storage areas. The bottom line is that corrosion jeopardizes expensive machinery, leads to a loss of production through downtime; moreover it may cause fires, explosions, or even toxic leaks, generally resulting in an increase in overall production costs and safety concerns^{10, 57, 58}.

Corrosion can be uniform or of a pitting nature, where penetration rates can be very high. The severity of corrosion is influenced by temperature, pressure, pH, and velocity, among other factors.

Common types of equipment that are vulnerable to corrosion include rods, tubing, pumps, and casings.

There are different types of methods to control corrosion of equipment:

- Cathodic Protection: It is used to control corrosion in pipelines, well casings, tanks, and pressure vessels.
- Chemical Treatment: These are used to protect the inside of the casing, tubing, and sucker rods from corrosion. Corrosion inhibitors, scale control, and biocides are certain chemical treatment to control corrosion.
 - Corrosion inhibitors: These are used to protect oilfields from corrosive fluids. These can be applied by continuous injection, batch treatments or squeeze treatments.
 - Scale control: These can be used to control the water soluble on surface, downhole, and squeeze in zone.
 - Biocides: These are bacteria control, which can be used in deposits, plugging and H₂S production.
- Coatings and Linings: Can be used to control corrosion in pipe, tubing, tank, and vessels.
- Corrosion resistant alloys: This is a high performance and cost method, which must be chosen and used carefully.

7.3 Reducing Electric Costs

Electric costs are a major economic factor in oil production. With the prevailing low oil price and continuing decline in production from domestic reservoirs, independent producers need available tools to improve economic margins. Reducing electric costs can significantly enhance the profitable margin in stripper wells by improving artificial lift efficiencies, using total well management, generating their own electricity, and seizing opportunities created by electric restructuring. This may lead to additional oil recovery and extended well life. There are simplistic strategies to lower the electrical power costs that operators should be applying for reducing electrical cost. They must gather information about the prior twelve months worth of all power bills. Then, they can

organize these by month and analyze them carefully, looking for anomalies in trends of gross oil and water volume, different rates and costs among the months. Rate design review can identify factors such as annual peak demand ratchets and power factor penalties that can significantly affect cost. To determine whether self-generation make sense for applying in a specific site, operators should determine which electric utility rate offers the lowest cost. Then, they can negotiate with their utility representative, and ask for an explanation about the rates and bills^{10,59,60,61,62}. Knowing these they could determine the expected power consumption and verify if this is in agreement with the bills.

Also, it is important that operators improve artificial lift efficiencies by looking at the pumping unit as a complete system. Problems in any subpart (electrical motors, belts, gearbox, balance system, meter, stuffing box, pump valves, gear, switch gear, power factor correction, and conductors) are usually very expensive. How equipment is operated and at what time of day (Timers and pump-off controllers can increase saving) and looking for inefficient uses of power can reduce costs.

Artificial lift technology involves several types of lift systems such as beam pumps, electrical submersible pumps, and progressive cavity pumps. Beam pumps are simple devices with complex behavior. It is the most common system for pumping oil in most US oilfields. Therefore, a new tool (BPEAT) for analyzing a beam pump has been developed. The Beam Pump Energy Audit Tool (BPEAT), is used to permit the rapid (a few hours to a to a day) non-intrusive evaluation of a beam pumping unit to determine the potential impact and cost effectiveness of individual electrical, mechanical, and control energy efficiency measures⁶².

There is another important tool (DER), which can be used for small independent producers to improve economics. Distributed Energy Resources (DER) are devices located where excess power can be sold into the existing

power grid, and in places where power generation can run off of field gas onsite, produce lower lifting costs.

CONCLUSIONS AND RECOMMENDATIONS

1. Solutions to production problems came from a number of sources as SPE library, Internet (generally PTTC papers), journals (JPT, IOGA), workshop conferences and formal interviews with the producers.
2. Graphical diagnostic plots of data are useful to assist the operator in identifying type of water production problem in the life of a well.
3. It is important to identify the cause of the water problem (mechanical, completion, and reservoir) before implement any technique.
4. Water handling play and important role in the cost of water separation and disposal.
5. ESP-DOWS could be applicable in certain well of the Appalachian Basin.
6. Waterflooding is affected by the degree of heterogeneity of the reservoir.
7. Waterflooding could be applied successfully in several fields in the Appalachian Basin.
8. In reservoirs where permeability measurements are not abundant, permeability must be predicted from well log data.
9. Artificial Neural Networks is a reliable tool for predicting permeability and flow units in heterogeneous reservoirs in the Appalachian Basin.
10. Log derived parameters such electrofacies do not provide a reliable guideline for flow unit or permeability prediction in the Jacksonburg-Stringtown or Granny Creek field.
11. Microbial treating can control paraffin deposition in well systems without causing lasting formation damage.

12. Corrosion can cause premature equipment failures leading high operating cost, lost of production and environment and safety problems.
13. Lowering electric cost can enhance economics of oil production.
14. Artificial lift efficiencies can be improved through analysis of unit as a complete system.
15. DER is another approach for enhancing project economics.

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APPENDIX A

Log Permeability vs. Porosity Distribution in each Well using Core Data and Electrofacies as a Guideline.

Figure A.1 Permeability vs. Porosity using Electrofacies 3 in Well P.Horner 9

Figure A.2 Permeability vs. Porosity using Electrofacies 3 in Well T.H 8

Figure A.3 Permeability vs. Porosity using Electrofacies 3 in Well Ball 19

Figure A.4 Permeability vs. Porosity using Electrofacies 3 in Well Ball 18

Figure A.5 Permeability vs. Porosity using Electrofacies 4 in Well P.Horner 9

Figure A.6 Permeability vs. Porosity using Electrofacies 4 in Well T.H 8

Figure A.7 Permeability vs. Porosity using Electrofacies 4 in Well Ball 19

Figure A.8 Permeability vs. Porosity using Electrofacies 4 in Well Ball 18

Figure A.9 Permeability vs. Porosity using Electrofacies 2 in Well Ball 18

APPENDIX B

Log Permeability vs. Porosity Distribution in each Well using Log Data and Electrofacies as a Guideline.

Figure B.1 Permeability vs. Porosity using Electrofacies 3 in Well P.Horner 9

Figure B.2 Permeability vs. Porosity using Electrofacies 3 in Well TH.8

Figure B.3 Permeability vs. Porosity using Electrofacies 3 in Well Ball 19

Figure B.4 Permeability vs. Porosity using Electrofacies 3 in Well Ball 18

Figure B.5 Permeability vs. Porosity using Electrofacies 4 in Well P.Horner 9

Figure B.6 Permeability vs. Porosity using Electrofacies 4 in Well TH.8

Figure B.7 Permeability vs. Porosity using Electrofacies 4 in Well Ball 19

Figure B.8 Permeability vs. Porosity using Electrofacies 4 in Well Ball 18

Figure B.9 Permeability vs. Porosity using Electrofacies 2 in Well Ball 18

APPENDIX C

Log Permeability vs. Porosity Distribution in each Well using Core Data and Flow Unit as a Guideline.

Figure C.1 Permeability vs. Porosity using Flow Unit 1 in Well P.Horner 9

Figure C.2 Permeability vs. Porosity using Flow Unit 1 in Well TH.8

Figure C.3 Permeability vs. Porosity using Flow Unit 1 in Well Ball 19

Figure C.4 Permeability vs. Porosity using Flow Unit 1 in Well Ball 18

Figure C.5 Permeability vs. Porosity using Flow Unit 2 in Well P.Horner 9

Figure C.6 Permeability vs. Porosity using Flow Unit 2 in Well Ball 19

Figure C.7 Permeability vs. Porosity using Flow Unit 2 in Well Ball 18

APPENDIX D

Log Permeability vs. Porosity Distribution in each Well using Log Data and Flow Unit as a Guideline.

Figure D.1 Permeability vs. Porosity using Flow Unit 1 in Well P.Horner 9

Figure D.2 Permeability vs. Porosity using Flow Unit 1 in Well TH.8

Figure D.3 Permeability vs. Porosity using Flow Unit 1 in Well Ball 19

Figure D.4 Permeability vs. Porosity using Flow Unit 1 in Well Ball 18

Figure D.5 Permeability vs. Porosity using Flow Unit 2 in Well P.Horner 9

Figure D.6 Permeability vs. Porosity using Flow Unit 2 in Well Ball 19

Figure D.7 Permeability vs. Porosity using Flow Unit 2 in Well Ball 18

APPENDIX E

Log Permeability vs. Gamma Ray Data in Wells using Flow Unit as a Guideline.

Figure E.1 Permeability vs. Gamma Ray using Flow Unit 1 in Well P.Horner 9

Figure E.2 Permeability vs. Gamma Ray using Flow Unit 1 in Well TH.8

Figure E.3 Permeability vs. Gamma Ray using Flow Unit 1 in Well Ball 19

Figure E.4 Permeability vs. Gamma Ray using Flow Unit 1 in Well Ball 18

Figure E.5 Permeability vs. Gamma Ray using Flow Unit 1 in all Wells

Figure E.6 Permeability vs. Gamma Ray using Flow Unit 1 in Well P.Horner 9

Figure E.7 Permeability vs. Gamma Ray using Flow Unit 1 in Well Ball 19

Figure E.8 Permeability vs. Gamma Ray using Flow Unit 1 in Well Ball 18

Figure E.9 Permeability vs. Gamma Ray using Flow Unit 2 in all Wells

APPENDIX F

Log Permeability vs. Density Data in Wells using Flow Unit as a Guideline.

Figure F.1 Permeability vs. Density using Flow Unit 1 in Well P.Horner 9

Figure F.2 Permeability vs. Density using Flow Unit 1 in Well TH.8

Figure F.3 Permeability vs. Density using Flow Unit 1 in Well Ball 19

Figure F.4 Permeability vs. Density using Flow Unit 1 in Well Ball 18

Figure F.5 Permeability vs. Density using Flow Unit 1 in all Wells

Figure F.6 Permeability vs. Density using Flow Unit 2 in Well P.Horner 9

Figure F.7 Permeability vs. Density using Flow Unit 2 in Well Ball 19

Figure F.8 Permeability vs. Density using Flow Unit 2 in Well Ball 18

Figure F.9 Permeability vs. Density using Flow Unit 2 in all Wells

APPENDIX G

Log Permeability vs. Gamma Ray Slope Data in Wells using Flow Unit as a Guideline.

Figure G.1 Permeability vs. Gamma Ray Slope using Flow Unit 1 in Well P.Horner 9

Figure G.2 Permeability vs. Gamma Ray Slope using Flow Unit 1 in Well TH.8

Figure G.3 Permeability vs. Gamma Ray Slope using Flow Unit 1 in Well Ball 19

Figure G.4 Permeability vs. Gamma Ray Slope using Flow Unit 1 in Well Ball 18

Figure G.5 Permeability vs. Gamma Ray Slope using Flow Unit 1 in all Wells

Figure G.6 Permeability vs. Gamma Ray Slope using Flow Unit 2 in Well P.Horner 9

Figure G.7 Permeability vs. Gamma Ray Slope using Flow Unit 2 in Well Ball 19

Figure G.8 Permeability vs. Gamma Ray Slope using Flow Unit 2 in Well Ball 18

Figure G.9 Permeability vs. Gamma Ray Slope using Flow Unit 2 in all Wells

APPENDIX H

Log Permeability vs. Density Slope Data in Wells using Flow Unit as a Guideline.

Figure H.1 Permeability vs. Density Slope using Flow Unit 1 in Well P.Horner 9

Figure H.2 Permeability vs. Density Slope using Flow Unit 1 in Well TH.8

Figure H.3 Permeability vs. Density Slope using Flow Unit 1 in Well Ball 19

Figure H.4 Permeability vs. Density Slope using Flow Unit 1 in Well Ball 18

Figure H.5 Permeability vs. Density Slope using Flow Unit 1 in all Wells

Figure H.6 Permeability vs. Density Slope using Flow Unit 2 in Well P.Horner 9

Figure H.7 Permeability vs. Density Slope using Flow Unit 2 in Well Ball 19

Figure H.8 Permeability vs. Density Slope using Flow Unit 2 in Well Ball 18

Figure H.9 Permeability vs. Density Slope using Flow Unit 2 in all Wells

APPENDIX I

Gamma Ray, Gamma Ray Slope, Density, Density Slope vs. Permeability in all Wells using Multiple Regression Method and using Electrofacies as a Guideline.

Table I.1. Electrofacies 3 (multiple regression method).

x1	x2	x3	x4				
Gamma Ray	Density	Gamma Ray Slope	Density Slope	Log K	K	Log K (asses)	K (asses)
41.322	2.558	-13.222	-0.08	0.518514	3.3	-0.27109	2.844336
34.711	2.477	-1.102	-0.022	1.60206	40	0.839933	19.29843
33.058	2.458	-3.306	-0.034	1.740363	55	1.199398	24.85038
38.44	2.519	-12.258	-0.008	-0.95861	0.11	0.255483	10.07788
38.44	2.544	2.228	0.024	-0.92082	0.12	-0.26774	2.744663
51.811	2.495	3.342	-0.03	-0.03621	0.92	-0.31448	-3.22792
51.253	2.488	-6.684	-0.038	-0.50864	0.31	-0.06601	0.464595
39.554	2.473	3.342	0.004	0.812913	6.5	0.550271	13.02485
47.911	2.467	4.456	-0.014	0.579784	3.8	0.196632	4.913552
29.917	2.492	5.54	-0.03	0.627366	4.24	0.83361	21.36209
32.687	2.476	6.648	-0.042	1.041393	11	0.885331	20.91465
37.119	2.509	3.324	0.006	-0.56864	0.27	0.235814	10.03174
40.997	2.519	7.756	-0.036	-0.79588	0.16	-0.09216	4.489874
42.659	2.473	-5.54	-0.016	1.230449	17	0.523144	11.64394
41.551	2.604	-16.62	-0.02	-0.11351	0.77	-0.87405	-5.69558
46.537	2.575	5.54	-0.142	-0.85387	0.14	-0.9077	-7.24909
27.147	2.461	-2.216	-0.014	1.623249	42	1.432618	30.25783
27.147	2.454	1.108	-0.03	1.30103	20	1.496007	31.2162
50.97	2.47	-11.08	-0.014	0.146128	1.4	0.193786	3.726984
43.767	2.468	-22.162	-0.014	0.176091	1.5	0.730383	14.03479
41.551	2.506	16.62	0.286	-0.10237	0.79	-0.46096	-4.40585
43.213	2.505	1.108	0	-0.42022	0.38	0.002355	4.391655

Permeability

m4	m3	m2	m1	b
-27.2562	-0.17436	-157.408	-1.11907526	447.2498
39.23359	0.322113	69.90786	0.388399893	171.8507
0.507775	12.37872	#N/A	#N/A	#N/A
4.384259	17	#N/A	#N/A	#N/A
2687.247	2604.956	#N/A	#N/A	#N/A

Log permeability

m4	m3	m2	m1	b
-1.20638	-0.01241	-12.1923	-0.05201388	32.80539
2.014601	0.01654	3.58969	0.0199439	8.824341
0.58229	0.635633	#N/A	#N/A	#N/A
5.924524	17	#N/A	#N/A	#N/A
9.574737	6.868507	#N/A	#N/A	#N/A

Table I.2. Electrofacies 4 (multiple regression method).

x1	x2	x3	x4				
Gamma Ray	Density	Gamma Ray Slope	Density Slope	Log K	K	Log K(asses)	K(asses)
39.669	2.418	5.508	-0.028	1.963788	92	1.50518165	36.69371
42.424	2.381	-1.102	-0.044	1.90309	80	1.59660512	62.38915
41.873	2.347	-2.204	-0.052	1.924279	84	1.88824589	109.3644
41.322	2.341	0	-0.006	2.089905	123	1.85732679	105.207
41.873	2.334	2.204	-0.012	2.133539	136	1.98671992	122.9056
45.73	2.289	5.51	-0.014	2.20412	160	2.3597515	182.4287
50.689	2.281	3.306	-0.014	2.130334	135	2.22617313	169.8833
52.342	2.274	2.204	0.002	2.158362	144	2.15064525	162.8376
55.647	2.284	1.102	0.01	2.093422	124	1.91761921	131.6202
55.647	2.288	0	0.016	2.170262	148	1.83082326	119.841
51.811	2.392	-1.114	-0.02	0.908485	8.1	1.16684247	6.703857
49.025	2.384	-2.228	-0.034	1.255273	18	1.32448323	28.96719
49.025	2.365	1.114	-0.004	1.342423	22	1.47597024	51.54259
52.925	2.359	5.57	-0.018	1.361728	23	1.60112944	68.46821
74.652	2.354	21.17	0.038	1.322219	21	1.3206703	32.1584
37.119	2.429	3.324	-0.016	1.579784	38	1.37646127	17.34233
39.889	2.424	5.54	-0.01	1.491362	31	1.3875403	19.80042
37.119	2.396	-8.864	-0.112	1.612784	41	1.62377739	64.82295
36.565	2.369	3.324	-0.012	1.812913	65	1.87410997	97.03683
41.551	2.399	7.756	0.096	1.230449	17	1.24438023	6.153938
43.767	2.432	0	0.008	0.83187	6.79	0.98887243	-30.0553
44.321	2.377	2.216	-0.04	1.863323	73	1.66276194	70.91212
43.213	2.365	4.432	-0.004	1.778151	60	1.73193825	81.17126
43.767	2.367	-4.432	0.004	0.064458	1.16	1.40936941	43.39151
39.335	2.358	1.108	-0.08	2.041393	110	2.06220339	126.8543
40.443	2.307	5.54	-0.008	2.025306	106	2.33395188	172.6761
43.767	2.293	-1.108	-0.01	2.31597	207	2.16947992	159.377
42.659	2.286	-2.216	-0.014	2.252853	179	2.2385639	170.3587
40.443	2.3	-8.864	0.018	2.093422	124	1.87354095	121.7727
44.321	2.355	9.972	0.06	1.414973	26	1.72518687	79.88375
50.97	2.36	21.054	0.096	1.531479	34	1.70649895	72.47396
33.795	2.396	-12.188	0	1.447158	28	1.22344547	12.52155
30.471	2.399	-3.324	0.014	1.732394	54	1.50274233	42.31304
39.335	2.324	12.188	-0.082	2.354108	226	2.67939073	210.0563
45.429	2.269	4.432	-0.034	2.409933	257	2.57142662	215.6199
48.753	2.274	2.216	0.02	2.31597	207	2.18530361	165.9976
49.307	2.284	1.108	0.008	2.255273	180	2.09661841	152.7758
52.632	2.294	11.08	0.028	2.25042	178	2.1496644	152.9972
63.712	2.35	25.484	0.038	2.136721	137	1.77827806	86.78511

Continuation of Table I.2

Permeability

m4	m3	m2	m1	b
-462.292	3.345678	-1329.63	-3.18783777	3346.817
145.9685	0.916413	115.7331	0.867304591	288.2488
0.808298	32.46856	#N/A	#N/A	#N/A
35.8396	34	#N/A	#N/A	#N/A
151129.5	35843.05	#N/A	#N/A	#N/A

Log permeability

m4	m3	m2	m1	b
-3.4981	0.029672	-8.27711	-0.02710173	22.33296
1.410659	0.008856	1.11846	0.008381748	2.785675
0.648783	0.313781	#N/A	#N/A	#N/A
15.70153	34	#N/A	#N/A	#N/A
6.183781	3.34758	#N/A	#N/A	#N/A

Table I.3. Flow Unit 1 (multiple regression method).

x1	x2	x3	x4				
Gamma Ray	Gamma Ray Slope	Density	Density Slope	Log K	K	Log K(asses)	K (asses)
98.072	-55.096	2.627	-0.044	-0.699	0.2	-0.941	-12.86
41.322	-13.222	2.558	-0.08	0.519	3.3	-0.039	8.92
34.711	-1.102	2.477	-0.022	1.602	40	0.633	20.69
33.058	-3.306	2.458	-0.034	1.740	55	0.815	24.98
39.669	5.508	2.418	-0.028	1.964	92	1.143	32.08
42.424	-1.102	2.381	-0.044	1.903	80	1.464	39.36
41.873	-2.204	2.347	-0.052	1.924	84	1.768	46.11
38.44	-12.258	2.519	-0.008	-0.959	0.11	0.224	10.94
38.44	2.228	2.544	0.024	-0.921	0.12	-0.011	5.08
51.811	3.342	2.495	-0.03	-0.036	0.92	0.432	17.29
51.253	-6.684	2.488	-0.038	-0.509	0.31	0.490	18.45
39.554	3.342	2.473	0.004	0.813	6.5	0.626	19.52
47.911	4.456	2.467	-0.014	0.580	3.8	0.671	21.53
51.811	-1.114	2.392	-0.02	0.908	8.1	1.306	35.01
49.025	-2.228	2.384	-0.034	1.255	18	1.401	37.59
49.025	1.114	2.365	-0.004	1.342	22	1.534	39.08
52.925	5.57	2.359	-0.018	1.362	23	1.595	41.30
74.652	21.17	2.354	0.038	1.322	21	1.516	37.91
84.211	-13.296	2.652	-0.022	0.387	2.44	-1.076	-15.12
29.917	5.54	2.492	-0.03	0.627	4.24	0.539	19.32
32.687	6.648	2.476	-0.042	1.041	11	0.684	23.05
37.119	3.324	2.429	-0.016	1.580	38	1.040	29.18
39.889	5.54	2.424	-0.01	1.491	31	1.069	29.64
37.119	3.324	2.509	0.006	-0.569	0.27	0.320	12.95

Continuation of Table I.3

40.997	7.756	2.519	-0.036	-0.796	0.16	0.276	14.34
42.659	-5.54	2.473	-0.016	1.230	17	0.626	20.16
37.119	-8.864	2.396	-0.112	1.613	41	1.423	41.41
36.565	3.324	2.369	-0.012	1.813	65	1.556	39.86
41.551	7.756	2.399	0.096	1.230	17	1.156	26.40
43.767	0	2.432	0.008	0.832	6.79	0.956	26.20
44.321	2.216	2.377	-0.04	1.863	73	1.492	39.92
43.213	4.432	2.365	-0.004	1.778	60	1.559	39.67
43.767	-4.432	2.367	0.004	0.064	1.16	1.518	38.03
44.321	9.972	2.355	0.06	1.415	26	1.573	37.09
50.97	21.054	2.36	0.096	1.531	34	1.479	33.93
83.657	16.62	2.503	0.188	0.124	1.33	0.007	-1.28
72.022	-34.348	2.615	-0.026	-0.585	0.26	-0.737	-8.90
41.551	-16.62	2.604	-0.02	-0.114	0.77	-0.515	-4.19
46.537	5.54	2.575	-0.142	-0.854	0.14	-0.105	11.49
33.795	-12.188	2.396	0	1.447	28	1.296	33.06
30.471	-3.324	2.399	0.014	1.732	54	1.278	32.33
27.147	-2.216	2.461	-0.014	1.623	42	0.788	23.38
27.147	1.108	2.454	-0.03	1.301	20	0.872	26.09
72.022	1.108	2.458	0.028	1.568	37	0.608	18.35
72.576	5.54	2.509	-0.024	-0.585	0.26	0.233	13.20
50.97	-11.08	2.47	-0.014	0.146	1.4	0.612	19.65
43.767	-22.162	2.468	-0.014	0.176	1.5	0.640	19.63
41.551	16.62	2.506	0.286	-0.102	0.79	0.014	-6.55
57.064	43.214	2.611	0.102	-0.602	0.25	-0.693	-11.02
86.981	-1.108	2.644	-0.008	-0.959	0.11	-1.016	-13.97
58.726	-47.644	2.527	-0.08	-0.585	0.26	0.119	10.97
43.213	1.108	2.505	0	-0.420	0.38	0.337	13.60

Permeability

m4	m3	m2	m1	b
-74.1749717	-182.38447	0.074057	-0.060386447	472.9978
51.806052	39.1883023	0.230511	0.206345731	93.31162
0.41223778	20.4135388	#N/A	#N/A	#N/A
8.2410774	47	#N/A	#N/A	#N/A
13736.6421	19585.4906	#N/A	#N/A	#N/A

Log permeability

m4	m3	m2	m1	b
-1.19792989	-8.6622435	0.001408	-0.003556302	22.18826
1.62798861	1.23147986	0.007244	0.006484349	2.932287
0.60107742	0.64148893	#N/A	#N/A	#N/A
17.704337	47	#N/A	#N/A	#N/A
29.1419082	19.340878	#N/A	#N/A	#N/A

Table I.4. Flow Unit 2 (multiple regression method)

x1	x2	x3	x4				
Gamma Ray	Density	Gamma Ray Slope	Density Slope	Log K	K	Log K (asses)	K (asses)
41.322	2.341	0	-0.006	2.090	123	2.061	111
41.873	2.334	2.204	-0.012	2.134	136	2.106	129
45.73	2.289	5.51	-0.014	2.204	160	2.262	189
50.689	2.281	3.306	-0.014	2.130	135	2.239	178
52.342	2.274	2.204	0.002	2.158	144	2.231	174
55.647	2.284	1.102	0.01	2.093	124	2.163	146
55.647	2.288	0	0.016	2.170	148	2.136	135
39.335	2.358	1.108	-0.08	2.041	110	2.077	121
40.443	2.307	5.54	-0.008	2.025	106	2.231	177
43.767	2.293	-1.108	-0.01	2.316	207	2.196	163
42.659	2.286	-2.216	-0.014	2.253	179	2.218	171
40.443	2.3	-8.864	0.018	2.093	124	2.101	124
39.335	2.324	12.188	-0.082	2.354	226	2.293	206
45.429	2.269	4.432	-0.034	2.410	257	2.333	217
48.753	2.274	2.216	0.02	2.316	207	2.240	177
49.307	2.284	1.108	0.008	2.255	180	2.202	163
52.632	2.294	11.08	0.028	2.250	178	2.230	173
63.712	2.35	25.484	0.038	2.137	137	2.111	126

Permeability

m4	m3	m2	m1	b
-307.773384	3.73695245	-1261	-2.485641657	3163.852
373.731809	1.68401658	363.2738	2.145285139	872.5544
0.5113389	34.0118962	#N/A	#N/A	#N/A
3.40082615	13	#N/A	#N/A	#N/A
15736.4263	15038.5181	#N/A	#N/A	#N/A

Log permeability

m4	m3	m2	m1	b
-0.65990648	0.00940375	-3.26687	-0.005852505	9.946909
0.99524297	0.00448451	0.967393	0.005712867	2.323601
0.48716272	0.09057324	#N/A	#N/A	#N/A
3.0872928	13	#N/A	#N/A	#N/A
0.10130657	0.10664565	#N/A	#N/A	#N/A