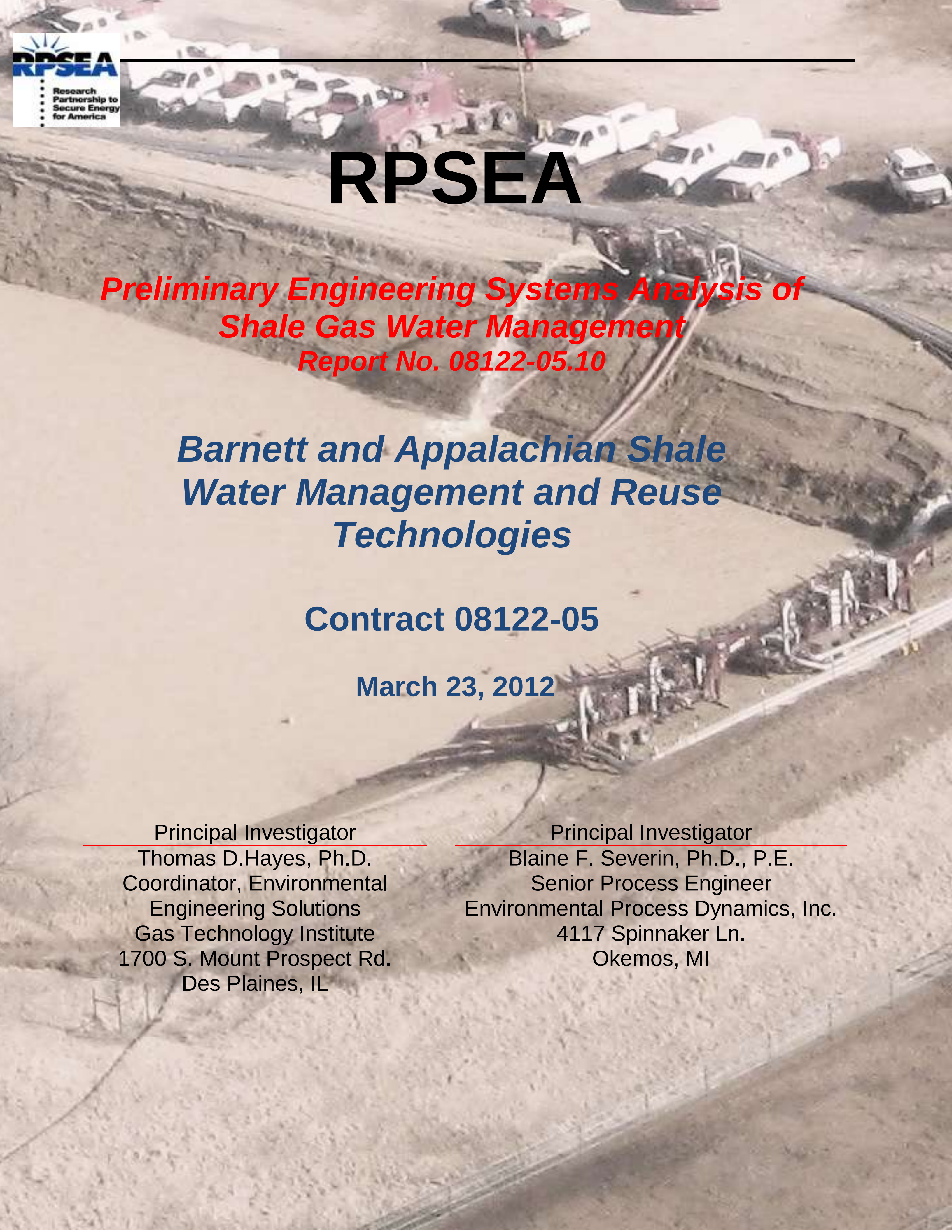

RPSEA

Preliminary Engineering Systems Analysis of Shale Gas Water Management
Report No. 08122-05.10

Barnett and Appalachian Shale Water Management and Reuse Technologies

Contract 08122-05

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Acronym and Abbreviations

Barnett	A geographic region in northern Texas
Bbl	Barrel = 42 US gallons
Closure	Removing a well from service
Completion	The termination of a drilling event
Cuttings	Rock generated during drilling
Drilling team	A single drilling rig
Duration	Life of a play in years
Field	A defined area of thousands of square feet containing multiple wells
First Crossover	Remaining reuse capacity becomes less than the planned collection volume (years)
Flowback	Water recovered immediately during the first 180 days after a fracture event
Installation	Days to complete a well
Marcellus	A geographic region in Pennsylvania and West Virginia
mg/l	Milligram per liter approximately ppm
Mobilization	Days between completion of a field and moving to a new field
Play	A defined area of hundreds of square miles containing multiple fields
Problem Water	Water that cannot be immediately reused
Produced Water	Water recovered during from a well after 180 days from after a fracture
Refracture	A repeat of the fracture procedure performed on a well
Second Crossover	The rate of creation of reuse capacity is less than the rate of collection (years)
Spent mud	Drilling lubricants, antioxidants, recovered during drilling
TDS	Total dissolved solids mg/l or pp,
Well	A single drilling event

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1 Abstract

The objective of this modeling effort is to simulate the characterize the chemical and hydraulic character of flowback water generated during the fracture of shale formations, and how these may influence the planning of gas generation facilities over a forty five year life cycle of individual wells, fields of wells, and plays of multiple fields.

Data collected at 19 wells in the Marcellus shale were analyzed for total salt production, flowback rates, and extrapolations for long term water recovery. The median Marcellus event was used to interpret water recovery during the expected life of a projected play based on the particular needs of gas generation in the Marcellus.

A Microsoft Excel Visual-Basic systems model was developed to incorporate a range of operating criteria on the projected life-cycle of the play. The core model tracks up to 32 wells per field at up to 350 fields per play. Concentrations and flow may be simulated by any reasonable set of parameters, such as the median Marcellus event. The projections are made on a daily basis for up to 30 years from the first completion. The variables include, but are not limited to, individual closure dates, number of wells per field, number of wells per field, number of refractures, installation rate, mobilization rate, days between refracture, number of drilling rigs mobilized, and recovered water rate.

The analyses show that there are three distinct periods in the life of a play; young age, middle age, and old age. The water flow and salt generation during each period will likely dictate a different water management strategy for each period. The magnitude of water and salt generation is exceedingly high and early planning for each period in the life of the play is recommended.

Extrapolations for the life cycle in Barnett are also presented based on the assumption that water and salt generation is similar to the median Marcellus flowback event. Differences in geology and aggressiveness in the development of each play, however, yield very different projections for the Barnett compared to the Marcellus. It is expected that each resource will need a water handling and management strategy tailored to some extent for that resource. Without sound strategies in place, water management has the potential to determine the pace of drilling, the number of refractures implemented, the periodicity of refractures, the life span of water reuse options, and the shut-in dates of individual wells.

2 Introduction

The hydraulic fracture of shale formations for the capture of natural gas is a relatively new technology. Recent work on North American shale formations has demonstrated the potential to capture trillions of cubic feet of high value gas. Other shale formations on other continents have the potential for development, therefore, potentially revolutionizing energy economies on a worldwide basis.

During the fracture process, between 1 and 4 million gallons of water and sand is expended “down hole” into each extraction well to aide in the fracture. A portion of this water is recovered during the initial extraction of the gas. The recovered fluid can contain high concentrations of dissolved salt, plus trace concentrations of residual anti-oxidants and lubrication fluids. Therefore, recovered flowback water presents a disposal problem, as well as a financial burden on the operation of the well.

The nature of the chemistry and dynamics of recovered water is of vital interest for effective environmental stewardship of a gas field. Development areas that are roughly the size of counties may more than a hundred well fields and each well field may contain one or two well pads from which 8 to 24 horizontal wells are constructed. Within a development area, thousands of wells are constructed, completed via hydraulic fracturing and then possibly stimulated again with more hydraulic fracturing during the life of the well. Each well, then, has its own pattern of water consumption, flowback water generation and produced water output during its life.

The output of water and salts from each well field and from the development area are important factors in the year-by-year changes observed in operating cost and in decision making on when wells and well fields need to be shut down. These calculations are best estimated as a summation of mass flows comprised of water and salts, yet as of the time period of the current project, no computer model has been presented or discussed in the literature. Such a model that is capable of forecasting water output, average brine concentrations, salt output and even solid waste generation is critical to the tracking of tens of millions of dollars per year of operating costs in a typical shale gas development area.

The purpose of this effort was to develop an approach for constructing a preliminary water-based life cycle model that has the capability of estimating the aggregate output of water and salt from a development area on a year by year basis to enable the engineer the ability to predict the occurrence of water management issues and challenges over the life of a shale gas development area. This modeling task is a part of a larger effort to define the flowback water chemistry, flow dynamics of recovery, and engineering solutions to lower the cost of water handling and minimize environmental impact. The development of rational treatment alternatives for flowback waters necessitates an understanding of the flow and salt profiles of the recovered water.

3 Background

Water is central to a large portion of operating costs and many of the potential environmental impacts of shale gas development. Water-based mud is used in drilling to transport cuttings and solids from the well bore to the surface. Most cuttings may be suitable for beneficial use, so it is important that low-cost technologies are identified for dewatering and rapidly classifying residues. For most shale gas plays, the management of water for fracturing is so massive that it comprises a major operational cost in terms of transportation, handling, and environmental control. The movement of a million gallons of water from surface water impoundments to the well pad requires 210 trucks. Delivery of 4 million gallons of water would require over 840 truckloads. Movement of the flowback and produced waters collected after well completion requires 210 truckloads for every million gallons of wastewater transported, if off-site disposal of the collected flowback water is required. Water handling and transportation affect multiple environmental factors including emissions, carbon footprint, traffic congestion, perceived public nuisance, public safety, and frequency of emergency spills and releases. In most shale gas plays, the strategy of recycling flowback and produced waters from a completed well and blending these brines with freshwater to supply water for the next well completion has been examined to reduce water demand, transportation cost, and ultimate disposal cost. Of course, the reuse of brine is limited by the ultimate number of well completions and "refracs". It is, therefore, important to have a computer model that is capable of forecasting water and salt generation for a development area and the point in time when reuse capacity is declining to the point where reuse capacity is exceeded by brine generation --- a point where other disposal options will need to be utilized to continue sustainable water management.

When constructing a shale gas water management model for a shale gas development area, it is important to have a good information base of water characteristics at numerous locations in a shale gas play that can be used to develop mathematical models of water and salt generation. Hayes (2010) presented data collected on flow and salt profiles of flowback water from the Marcellus formation. Salt (TDS) concentrations from the influent to the storage reservoirs and the total volume of water collected on 1, 5, 14, and 90 days after the fracture event were collected from 19 wells (Table 1). From the Marcellus data, three observations were made:

1. The ultimate recovery of water is less than 35% of the initial charge on a weighted basis of flow from all wells.
2. The flow rate of flowback water from the wells is initially high then decreases rapidly with time; most of the water (80%) is collected within the first 14 days after the fracture event. Less than 20% flowback recovery occurs between days 15 and 90.
3. The concentration of salt increases as a function of time after fracture. Four data sets show salt concentrations at 14 and 90 days. The 90 day concentrations are 50% greater than the 14 day concentrations.

Within the Marcellus information base, twelve of the data sets (associated with 12 locations) contain sufficient information to develop empirical correlation of flow versus time and salt concentration versus time for the individual events. These two correlations, when analyzed together, yield a third correlation between total salt recovered versus total flow recovered for each event. Surprisingly, eight of twelve events showed remarkably similar total salt versus total volume profiles. This kind of information is important to the construction of equations for the computer model that can make estimates of water and salt output throughout the anticipated life of a development area. Examples of the use of these equations to make projections (plots) of brine concentrations and salt output from a development area are shown in Figures 1 and 2, respectively.

Figure 1 is a summary of the projected mass of salt collected versus the barrels of flowback water recovered in a low salt recovery event Site E, Table 1), a high salt recovery (Site F, Table 1) and the Median Marcellus Event.

Flowback water is designated in this report as the water collected immediately after a fracture event. The correlations established in Appendix A are extrapolated to 180 days to represent the flowback recovery.

Produced water is designated as the water recovered after 180 days after the fracture event. The volume of produced water is not well documented, except by anecdotal account from various drilling companies. Produced water generation ranges from less than 4 barrels/day to 15 barrel/day in the Marcellus. Reports from the Barnett range from 10 to 30 barrels/day.

Table 1: Recovered Flow-back Water Inventory for The Marcellus (After Hayes, 2009)

Site	Total Used Bbls	Barrels Recovered by Days After Fracture				Barrels Recovered %	Input Frac Fluid mg/L	Well Stream Concentration (mg/l) Days After Fracture			
		1	5	14	90			1	5	14	90
A	40,046	3,950	10,456	15,023		38	990	15,400	54,800	105,000	216,000
B	94,216	1,095	10,782	13,718	17,890	19	27,800	22,400	87,800	112,000	194,000
C	146,226	3,308	9,652	15,991		11	719	24,700	61,900	110,000	267,000
D	21,144	2,854	8,077	9,938	11,185	53	1,410	9,020	40,700		155,000
E	53,500	8,560	20,330	24,610	25,680	48	5,910	2,890	55,100	124,000	
F	77,995	3,272	10,830	12,331	17,413	22	462	61,200	116,000	157,000	
G	123,921	1,219	7,493	12,471	31,735	26	1,920	74,600	125,000	169,000	
H	36,035	3,988	16,369	21,282		59	7,080	19,200	150,000	206,000	345,000
I							265	122,000	238,000	261,000	
J							4,840	5,090	48,700	19,100	
K	70,774	5,751	8,016	9,473		13	804	18,600	39,400	3,010	
L							221	20,400	72,700	109,000	
M	99,195	16,419	17,935	19,723		20	371			228,000	
N	11,435	2,432	2,759	3,043	3,535	31	735	31,800	116,000		
O							2,670	17,400	125,000	186,000	
P							401	11,600	78,600	63,900	
Q	23,593	1,315	3,577	5,090		22	311	16,600	38,500	120,000	
R							481	15,100	46,900	20,900	
S	16,460	2,094	7,832	9,345	10,723	65	280	680	58,300	124,000	

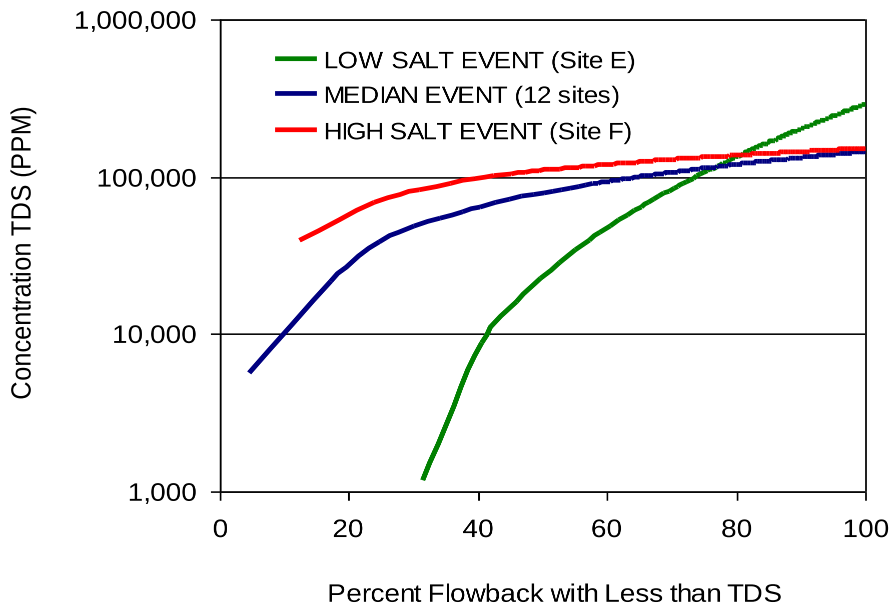

Figure 1: Percent of Flowback Water with Less than Stated TDS

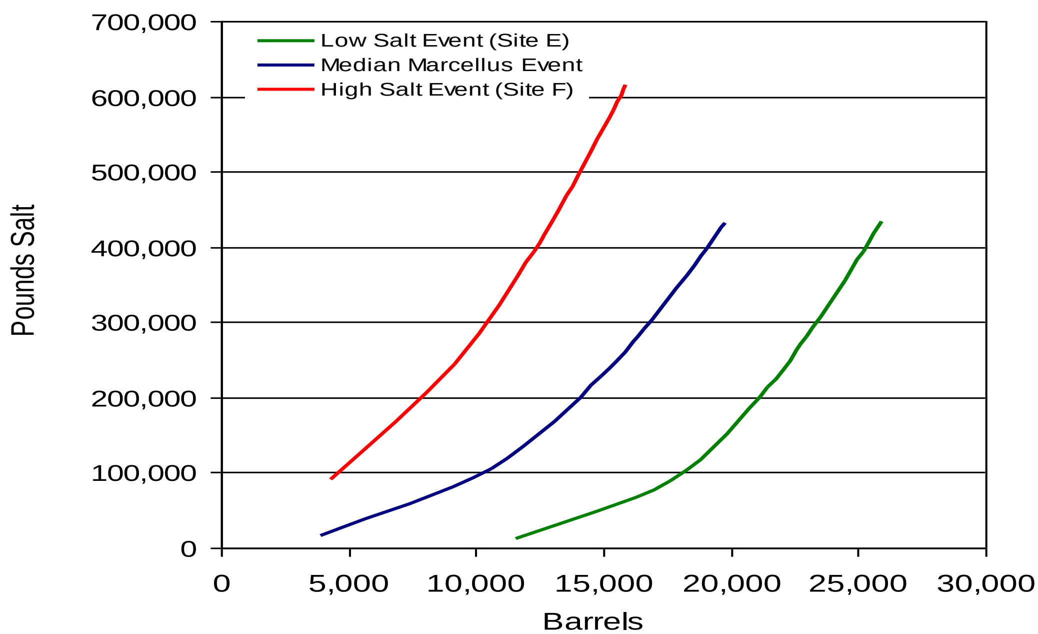

Figure 2: Salt Recovered vs Barrels Collected. Projected for a Range of Flowback Events

4 Model Development

The computer model is written in Microsoft Excel Visual Basic. The concept behind the model is to establish the relative dates for initiation, completion, refracture(s), and closure for a single well. The results for a single well are then reproduced for all wells in a field based on the initiation of each individual well. The results for the entire development area are then reproduced by duplicating the dates for the field, offset as dictated by a number of operational variables. The result is a compilation of the significant dates for up to 32 wells per well field and for up to 500 well fields per development area on a daily basis for up to 30 years. Data for flows, concentrations, cumulative sums of mass, etc. are calculated at various points within each computational loop. In most of the analyses presented, herein, the daily events are summarized on a yearly basis for ease of presentation. The variables in the model are presented in Table 2.   The parameters in Table 2 relate to the simulation used for the Median Marcellus event with an estimated long term water recovery of 7 barrels/day/well over the life of a shale gas development area which is approximately the size of a typical Pennsylvania county (625 sq mi).

Table 2: Operational Parameters Used in Most Model Analyses

Parameters Used in Most Model Analyses			
Define the duration of field in years			30 years
Closure (days after final refracture)			8000 days (29.1 years)
Number of wells in a field			16
Number of fields in development			300 (48% coverage)
Total Projected wells			4,800
Concentration of the produced water ppm			250,000
Number of refractures expected			3
Days to install a single well			25
Days between install and next well start			7
Days to mobilize to new field			3
Days between completion and refracture			1,000
Produced water bbl/day			7
Number of driller teams			12
Spent Drilling Mud Recovered per well			53 Tons
Rock Cuttings per well drilled			873 Tons
Flow Equation	parameter 1	AQ	3,400
	parameter 2	BQ	3,200
Salt equation	parameter 3	k3	0.0067
	parameter 4	k4	1.8526

5 Model Results for an Example Development Area in the Marcellus Shale (Pennsylvania, USA)

5.1 Base Case and Life Cycle Events

The basis for the example development area within the Marcellus Shale Region includes 16 wells per field and 300 fields per play for a total of 4800 wells. It is instructive to first evaluate the completion of the first field of 16 wells. With a drilling rate of 25 days per well and an installation delay of 7 days between wells, the first field takes about 1.5 years to complete. Figure 3 shows the range of flows and concentrations generated leading up to the completion of the first field. There is a slow increase in the daily maximum flow and the daily concentration. This reflects the impact of the recovered water (7 bbl/day, herein) on both the total daily flow and the concentration.

Many drilling companies in the Marcellus plan to reuse much of the flowback water for completing a subsequent well. Certainly the daily variability of the flow rate and the quality of the flowback water will impact the choice of on-site pretreatment processes (such as suspended solids, iron control, and other quality issues) needed to process the flowback for reuse. Daily choices may also be made on segregation of extremely salty water to be sent off-site, as opposed to immediate reuse. The end of easy on-site reuse begins at the completion of the final well on or about 1.5 years. The flowback water from the final well in the field must all be transported off-site. Water generated past 1.5 years at this field slowly becomes more and more concentrated. Ultimately about 100 bbl/day of concentrated brine is generated from the field. Since these flows will be generated from 16 individual wellheads, some provision should be made for ease of collection, storage, and off-site transport prior to drilling the first well.

Under certain conditions, refracturing is applied to wells to prevent natural gas production rates from declining to uneconomical levels. The model allows for three or more refractures planned for each well during the life of the play. Based on the assumption that each well will be refractured three times, with a timed spacing of 1000 days between planned events, then the planning for recovery of flowback and produced water does not diminish with time. Figure 4 is a plot of the planned drilling and three refractures for the first field of 16 wells.

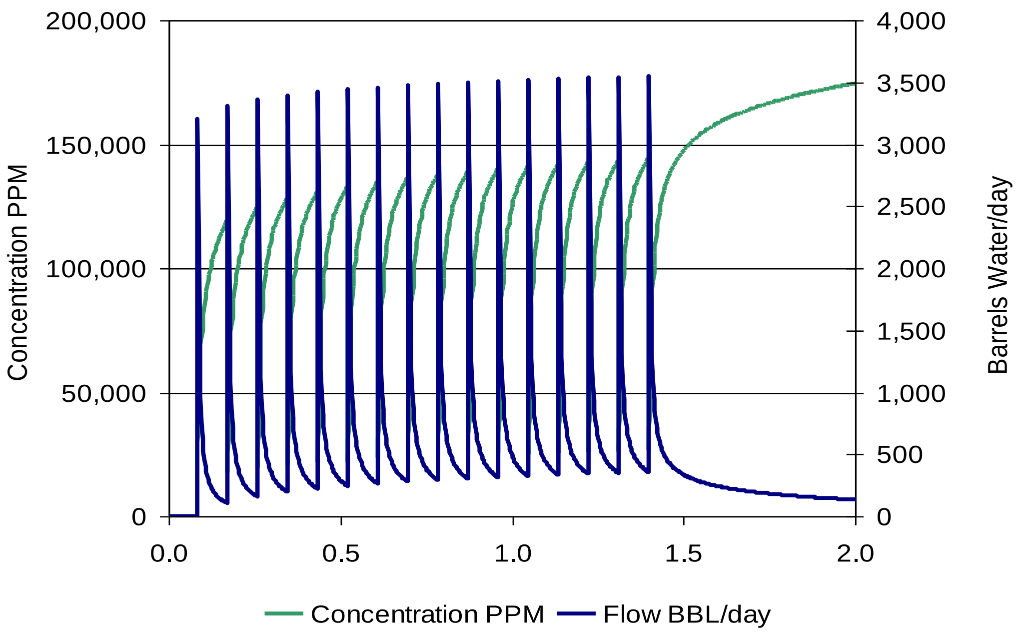

Figure 3: Example of the Flows and Concentrations Expected during the Completion of the First Field of 16 Wells

The decision to refracture a specific well should be made on the economics of gas production, and may or may not match the 1000 day cycle presented here. However, Figure 4 clearly shows the square wave profile between the routine collection of produced water and the vastly different recovery of flowback water. The process needs during the peaks of flowback water recovery and the valleys during produced water recovery are different, even on the smallest scale. An example is the pumping and storage needs during the cycles are vastly different from peaks of 3500 bbl/day down to 100 bbl/day. Figure 4 demonstrates the need to carefully engineer systems that are either mobile or maintainable on-site over a long down time.

The long term view of water management becomes even more crucial when the life-time of the play is considered. Some planners are considering the creation of up to 300 fields, each with 16 wells, for a 25 mile x 25 mile area, with upwards of 50% cover of the play. The model was used to define event dates for the activity needed to support 4800 wells. The assumptions in Table 2 were used to generate a table of fracture events over a 30 year period based on the use of 12 drilling teams to create 4800 wells (Table 3). The water management plan for the play needs to incorporate 19,200 fractures with the baseline control of produced water recovery from each of the 4800 wells.

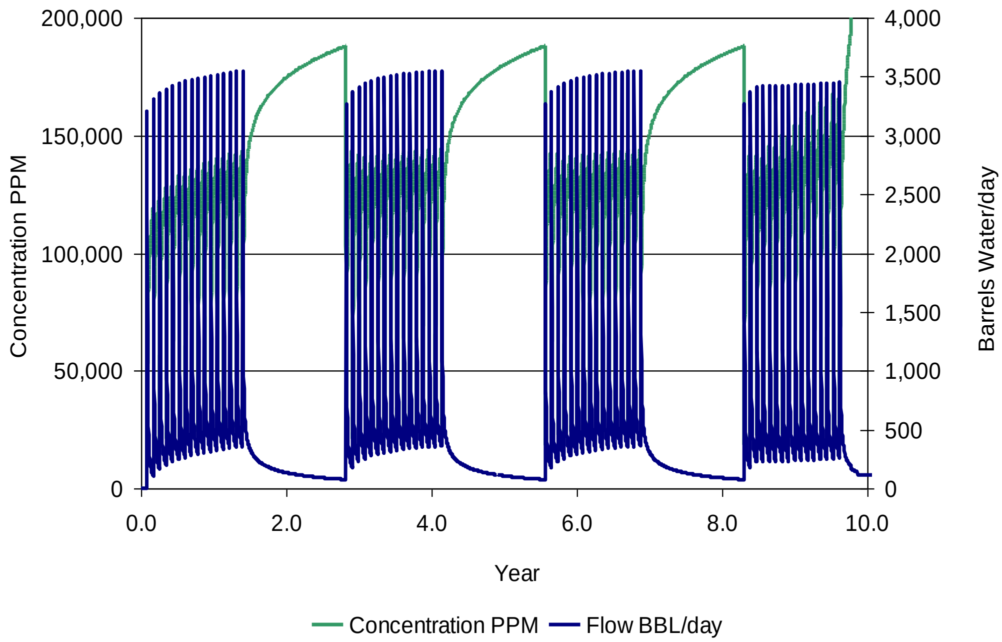

Figure 4: Planned Initial Fracture and Three Refractures One Field of 16 Wells (1000 Days between Fractures)

It is instructive to examine the yearly water management issues projected for 4800 wells with 19,200 fractures over a 30 year period. The Marcellus area has some unique water management issues that arise from the proscription of brine discharges to POTW facilities and the dearth of deep well injection resources for final disposal of flowback and produced water.

A current practice in the Marcellus is to use as much of the recovered flowback water, as possible, as part of the feed water for the next fracture. A common fracture event requires about 4 million gallons, or about 95,000 barrels of water. A typical recovery of flowback water is 1 million gallons, or about 24,000 barrels. Each subsequent fracture would require 3 million gallons fresh water plus the 1 million gallons collected from the previous fracture. Therefore, if 19,200 fractures are planned in a 300 field play, then each fracture reuses a water volume equivalient to 25% of 4 million gallons, for a total planned (initial) reuse capacity of 19,200 x 24,000 = 461,000,000 barrels. As each hydraulic fracture occurs, the reuse capacity of that fracture is used-up. It is a matter of book-keeping to compare the total planned reuse capacity associated with 19,200 fractures versus the cumulative total of the flowback water plus produced water collected over time.

Table 3: Drilling and Refracture Support of 4800 Wells in a Play of 300 Fields each with 16 Wells

Year	Initial Drilling	Refracture Events	Total Fractures
1	141	0	141
2	391	0	391
3	416	8	424
4	419	220	639
5	416	412	828
6	418	455	873
7	416	711	1127
8	419	836	1255
9	416	917	1333
10	418	1193	1611
11	416	1248	1664
12	385	1255	1640
13	129	1248	1377
14	0	1255	1255
15	0	1169	1169
16	0	904	904
17	0	832	832
18	0	690	690
19	0	441	441
20	0	409	409
21	0	193	193
22	0	4	4
23	0	0	0
24	0	0	0
25	0	0	0
26	0	0	0
27	0	0	0
28	0	0	0
29	0	0	0
30	0	0	0

Figure 5 is an example of a 19,200 fracture Marcellus development area that assumes an even larger share of reused water (33%) could be combined with fresh water to prepare the influent feed water for future hydraulic fracturing events. This is an even greater fraction of reused water in the frac job blends than assumed in the above discussion. The red line represents the planned reuse capacity of the development area (county sized). The blue line represents the recovered flowback plus produced water – or the recovered water line. The green line represents the average concentration of the recovered water. The planned capacity curve crosses the recovered water line at about 11.5 years into the life of the play. For reference, this will be termed the first cross-over point.

The significance of the first cross-over point is that it demarks the transition between a young play and a middle aged play. In the years up to the cross-over, the axiom holds that "all the recovered water can be sent back down-hole". At year 11.5, however there remains less reuse capacity available than the projected future recovery. At year 11.5 it becomes difficult to schedule enough reuse to keep up with the generation of flowback and produced waters. If alternatives enabling treatment and beneficial reuse or disposal have not been developed, the focus of the shale gas enterprise could change from the business of gas production to the business of water management. One possible consequence is that competing companies will begin to trade excess recovered water for the opportunity of disposal. Another consequence is that the frequency of choosing long distance disposal options will certainly increase.

This first cross-over from a young play to a middle-aged play is quite recognizable, and is something that should be planned for before the first well in the first field is ever drilled.

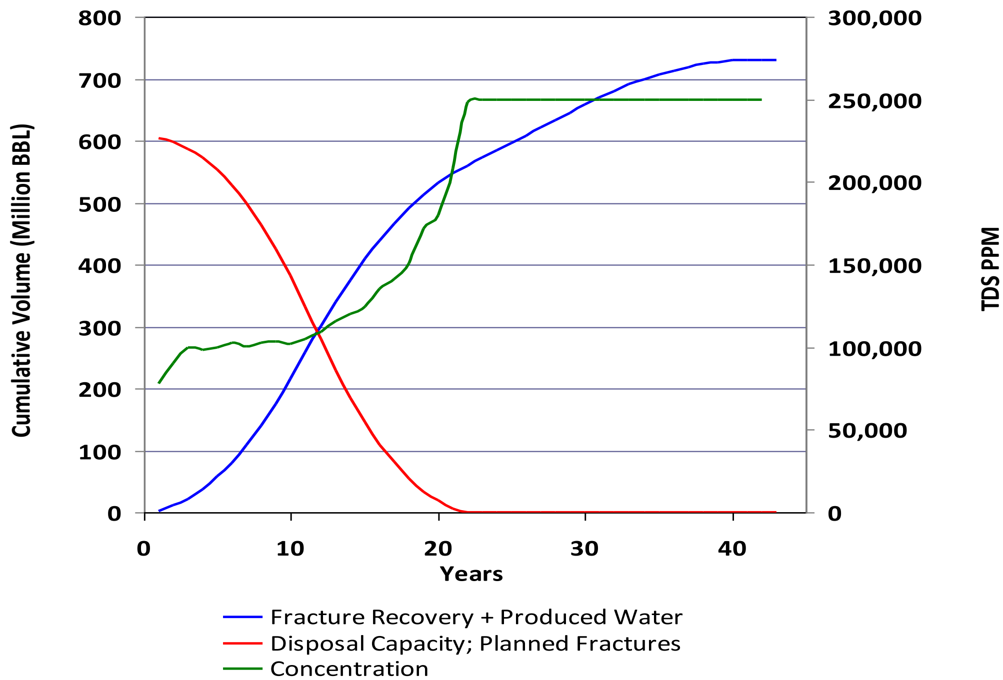

Figure 5: Cumulative Fracture and Process Water Recovery vs Projected Reuse Capacity in a 19,200 Fracture Play Assuming 33% Blend of Recovered Water in Each Fracture

Figure 6 is another way of mapping the fate of the water recovery versus reuse capacity. Once again, a generous ratio of 33% blend of recovered water to total water use in the fracture is assumed. Figure 6 shows the rate of total water recovery versus the rate of reuse capacity. The red curve represents the rate of creation of reuse capacity and essentially reflects the rate of fracture events. The blue curve represents the rate of collection of flowback water and produced water. The green line is a reference line for the average concentration of the collected water. The plum colored curve is the rate at which non-reuse options will be needed in the future. Non-reuse options may be resource recovery systems, brine volume reduction, and/or long-distance hauling of concentrated brines to deep-well injection.

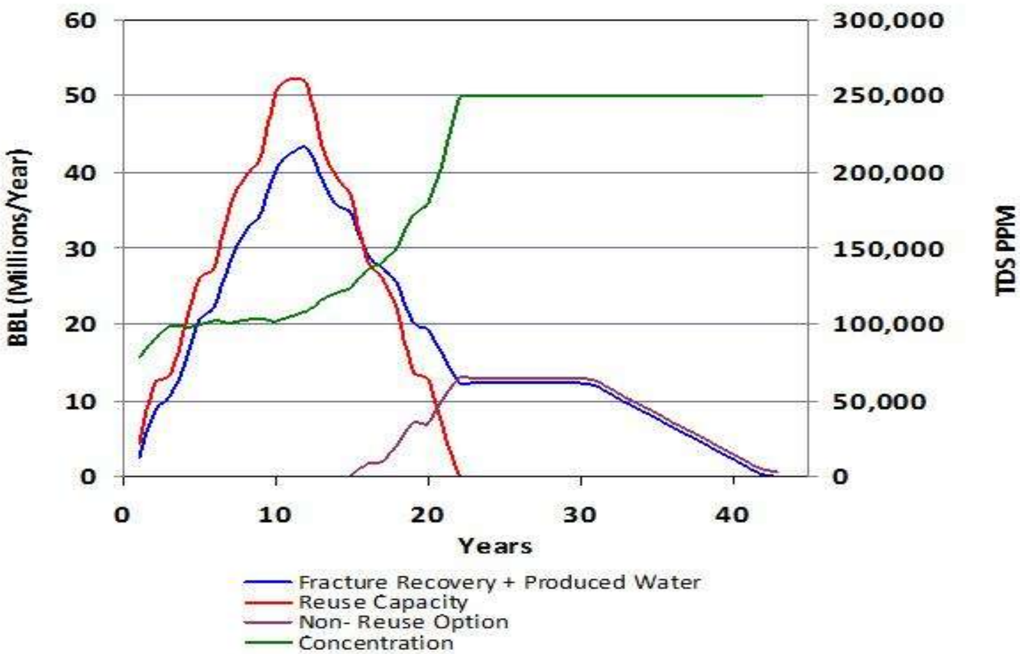

Figure 6: Comparison of the Rate of Fracture and Process Water Recovery vs. Rate of Resure Capacity in a 19,200 Fracture Play Assuming 33% Blend of Recovered Water in Each Fracture

The red curve crosses the blue curve at about year 15.5 into the life of the play. This cross-over, termed the second cross-over, represents the critical point in the life of the play where the generation rate of flowback and produced water exceeds the annual rate of available capacity for reuse options. The life of the play has crossed from middle-age where water management was difficult to old-age where water management is impossible without intervention. The plum colored curve in Figure 6 represents the need for non-reuse options, which begin in earnest in year 15 and culminates in about 13 million barrel/year by year 22. At around year 30, the first wells are in closure and the water recovery slowly diminishes until the last well is closed in around year 44. In the intervening years between the first and second cross-overs, the average of the collected water increases steadily from 100,000 to 150,000 ppm. This may (or may not) cause problems with maintaining effective use of the various chemical additives used in the hydraulic fracture.

The magnitude of the salt generation problem is expressed in Figure 7 (based on the assumptions in Table 2). Considering the first crossover point based on remaining capacity at 11.5 years, more than one half of all the salt generated in the 4800 well play will need to be handled using a non-reuse option. This problem water may exceed 500 million barrels containing 24,000 million pounds of salt over the next 30 years.

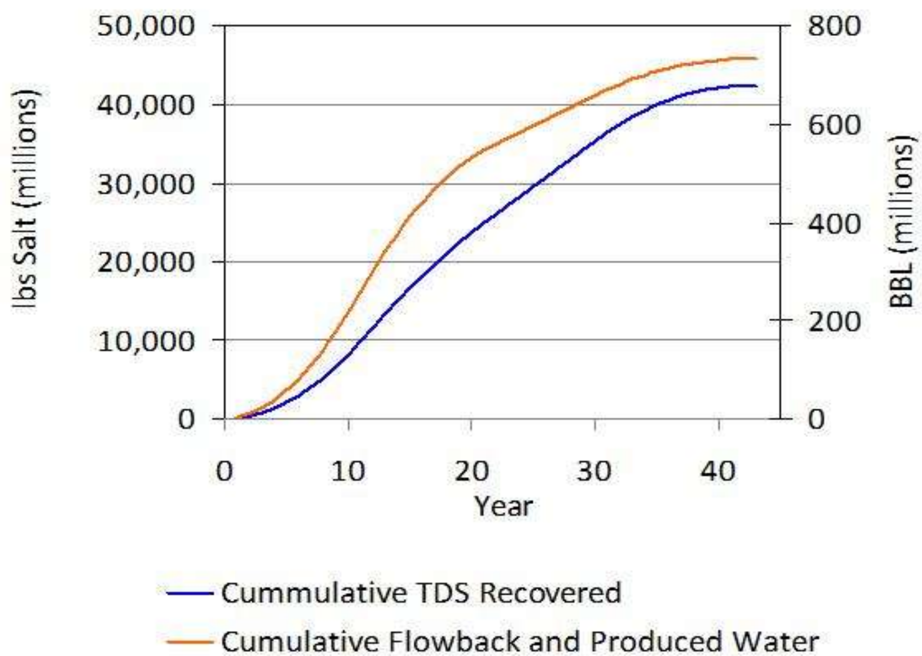

Figure 7: Magnitude of Water Recovery and Salt Generation in a 4800 Well Marcellus Play
Assuming the Median Fracture Event and 7 bb/Day Process Water

The concept that the life of a play will pass from youth, to middle age, to old age in a predictable fashion is an outcome of the modeling exercise performed in this study. The following examples examine the influence of various operational parameters on the life cycle events in the Marcellus.

5.2 Sensitivity: Number of Refractures per Well and Life Cycle Events

One operational strategy to improve the efficiency of gas production is to hydraulically refracture the well several times throughout its life. Figure 8 is a sensitivity analysis using the assumptions of Table 2, with the only variable being the number of planned hydraulic refractures per well, ranging from 0 to 4. While planning fewer refractures per well will diminish the magnitude of the water management problem, it does not change the premise that the play will pass from young, to middle-age to old-age. In fact, planning fewer refractures per well causes the onset of middle-age and old-age to accelerate. In a sense, the development of the development area is extended by continued refractures, if such measures are justified from a cost-benefit standpoint. The larger the number of fractures planned, the easier it is to reuse flowback and he produced water.

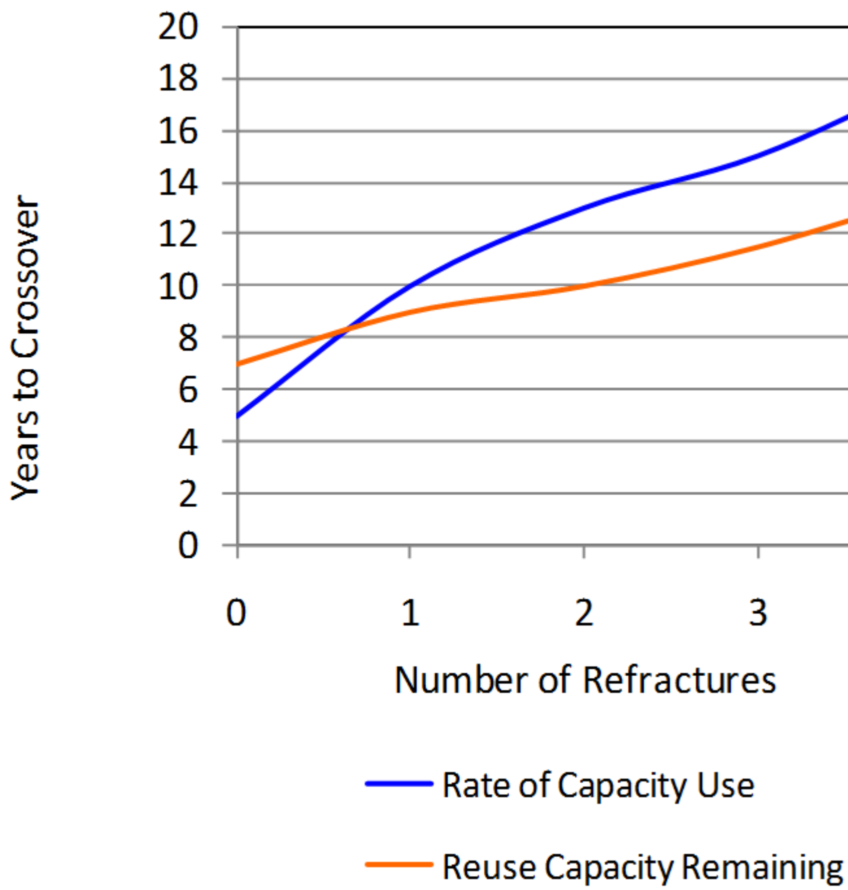

Figure 8: Sensitivity Analysis: Onset of Cross-over Points Based on the Number of Planned Refractures per Well

5.3 Sensitivity: Water Reuse Blend Ratio and Life Cycle Events

In the base case (Figures 5, 6, and Table 2), the assumption is made that recovered water (flowback and produced water) may be blended with fresh water to formulate the hydraulic fluid for the subsequent fracture. The base case assumes a 33% reuse ratio, i.e., 100,000 barrels of fracture fluid may be prepared with 33,000 barrels of recovered water blended with 67,000 barrels of fresh water. This is an aggressive assumption, as current field practice is a reuse ratio of about 25%.

Figure 9 is a sensitivity analysis based on the ability to reuse water in a subsequent fracture. The point of this plot is that even if 100% of the total water used for fracture could be recycled water, there will come a point in the life cycle of the play where the water collected exceeds reuse capacity. Essentially, produced water is recovered but no more fractures are planned. The play passes from middle-age to old-age, regardless of the ability to reuse captured water. Increasing the reuse blend ratio delays the inevitable.

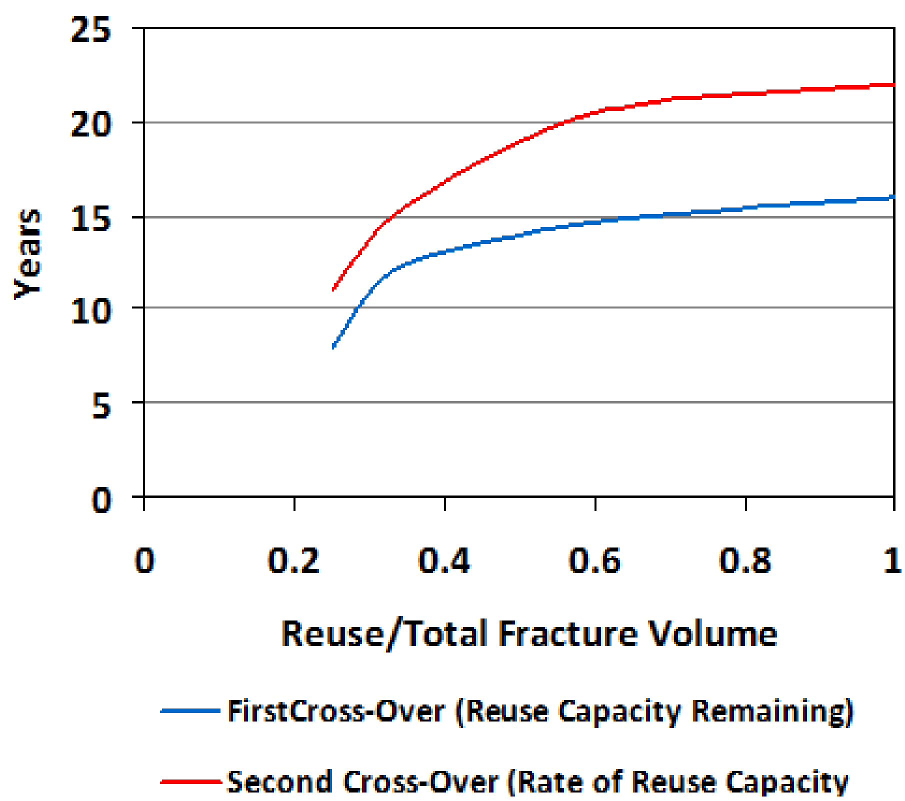

Figure 9: Sensitivity Analysis—Onset of Cross-over Points Based on the Ability to Reuse Recovered Water in the Next Fracture

5.4 Sensitivity: Rate of Produced Water Recovery and Life Cycle Events

It is common to differentiate between flowback water generated by the hydraulic fracture and produced water generated as a consequence of natural gas collection. In the present discussion a reasonable assumed set point of 180 days from the fracture event is used to distinguish flowback water from produced water. The generation rate of flowback water follows the median Marcellus event. The generation rate of produced water is a variable in the model. In the base case, this is set at 7 barrels per day per well and a concentration of 250,000 ml/l TDS. Figure 10 shows the cross-over years as a function of produced water flow. The grace period leading to the point where the rate water recovery exceeds the rate of reuse capacity generation is about 21 years if the produced water flow is 1 barrel/well/day. This steadily decreases to 13 years at a rate of 15 barrels per day. Even if the produced water is only one barrel/day, the life cycle events caused by water management issues still occur.

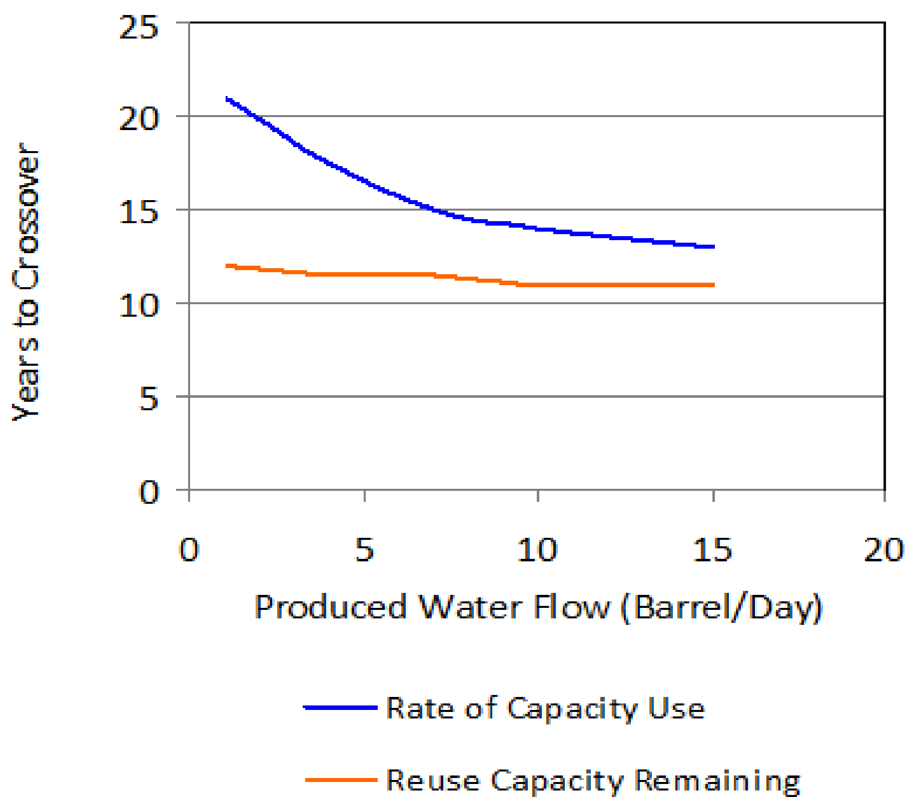

Figure 10: Sensitivity Analysis, Definition of the Cross-Over Years in Total Reuse Capacity and Rate of Capacity Use vs Produced Water Flow per Well

Figure 11 is an analysis showing the volume of the problem water after the first cross-over point at 11.5 years based on the daily flow of produced water between 1 and 15 barrels per day. The point to be taken from Figure 11 is that the problem water does not go away, even if the produced water flow diminishes to 1 barrel/day per well.

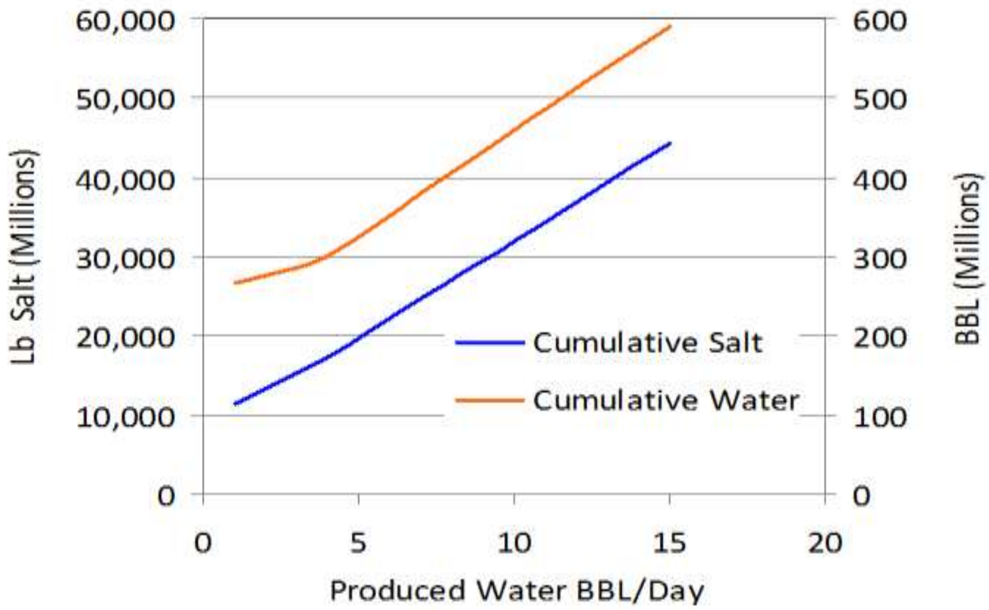

Figure 11: Non-Reuse Requirements for the Marcellus Representing Collection Past the First Crossover Point at 11.5 Years vs Produced Water Generation

5.5 Sensitivity: Rate of Scheduled Refracture and Life Cycle Events

Water management in the Marcellus has the potential to dictate the rate of refracture if an effective strategy that allows for contingencies is not in place. Assuming 4800 wells with three refractures per well, and 7 barrel per day per well of produced water after the flowback event, the grace years until the first cross-over (booked capacity) and critical years (rate of water recovery versus rate of capacity generation) are also a function of the scheduled period between refractures. Figure 12 is a sensitivity analysis of the years to cross-over versus the number of days a well operates between refracture events.

Based on this plot, there is an optimum rate of refracture that occurs at around 2125 days between refractures at a given well. The driver creating this optimum is the delicate balance between the initiation of refracture and the completion of the last well.

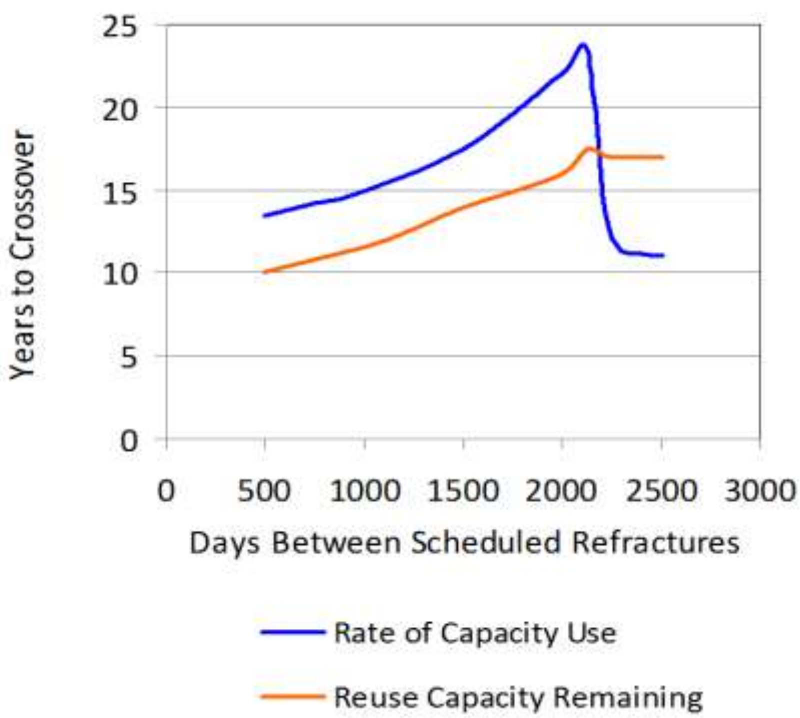

Figure 12: Sensitivity Analysis, Effect of Refracture Schedule on Utilization of Reuse Capacity

The visualization of a play utilizing an optimum period between refractures is presented in Figure 13, where the water recovery and capacity generation and salt concentrations are plotted for a scheduled period of 2125 days. This figure may be directly compared to Figure 6 which is based on a refracture period of 1000 days. Figure 13 demonstrates that the grace period to old age can be extended up to around 24 years in the play. However, this requires a challenging balancing act to be managed with potential crises occurring during years 2-3 and 8-9. There are several draw backs to such an extended refracture periodicity. There is a reliance on ability to collect and utilize produced water in an effective manner. Small amounts of produced water will need to be collected from a large number of wells. Furthermore, the average concentration of the collected water will exceed 140,000 mg/l TDS. However, the biggest drawback is that business of gas production has the risk of becoming the business of water management.

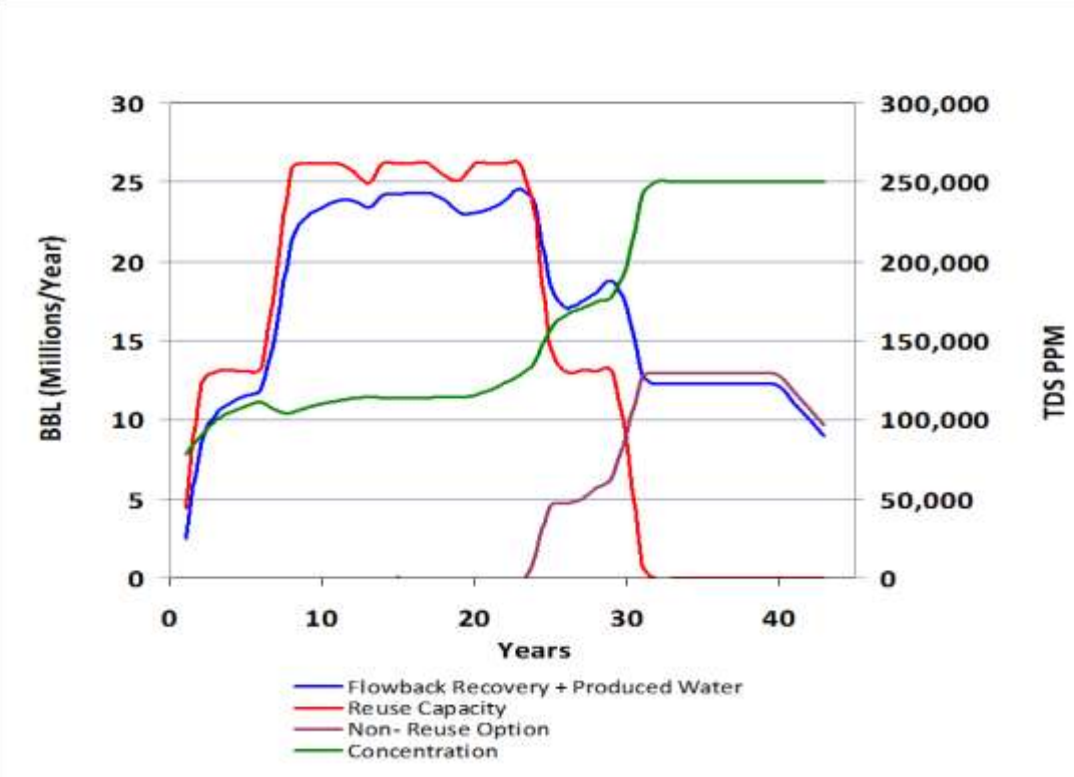

Figure 13: An Apparent Optimum Refracture Rate for Median Marcellus Flowback at 4800 Wells, Three Refractures per Well, Occurs at 2125 Day Intervals

Sensitivity: Mitigation of Flowback Volume and Life Cycle Events

One of the water management strategies is the potential mitigation of the flowback event by increasing the down-well hold-time before the release of the flowback water. The challenges to the engineering assumptions in such a modeling exercise are to be expected without more extensive database analysis. Regardless of the validity of the assumption that hold-down time influences flowback recovery, however, a first approximation would be to accept that premise, as given. Figure 14 is an example if 50% of the flowback water could be mitigated. This figure is based on the further assumption that the recovered flowback reflects the concentration expected in the final 50% of the flowback volume. More specifically, instead of 20,800 barrels collected in 180 days, the flowback was held down-well a sufficient time for about 10400 barrels to dissipate into the subterranean shale. Only about 10,400 barrels is recovered per fracture.

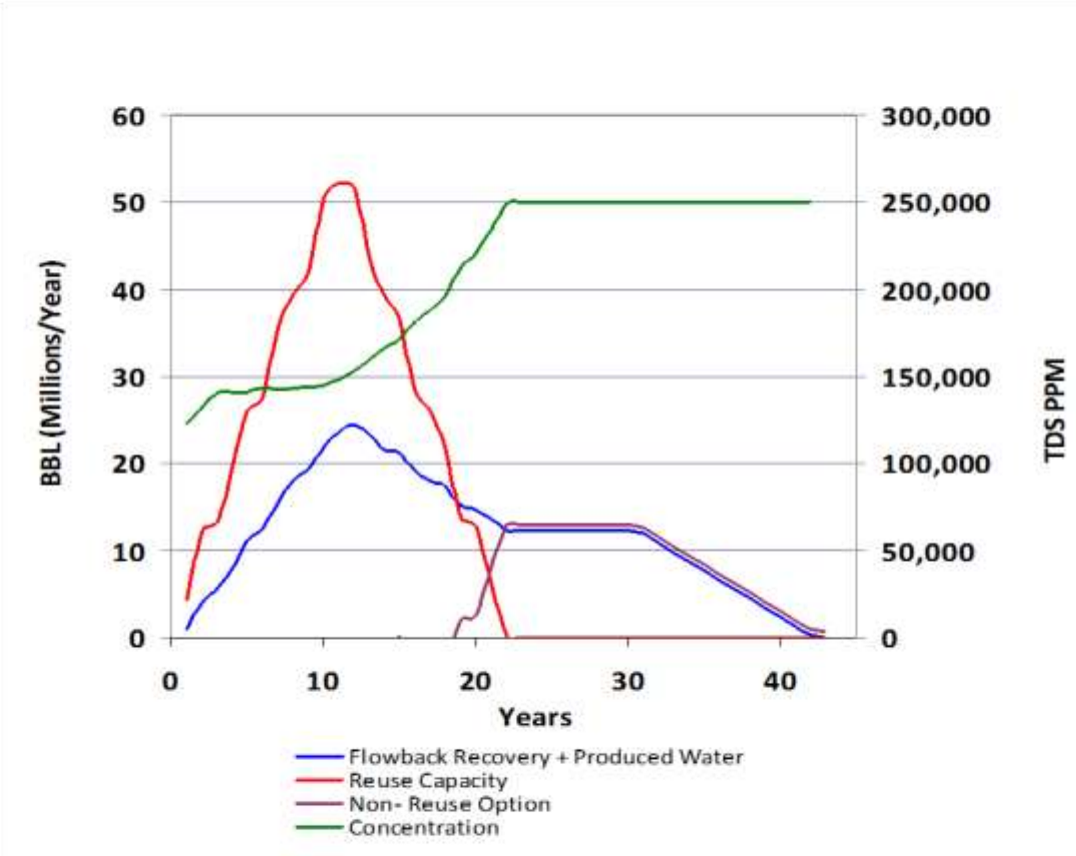

Figure 14: Presumed Effects of 50% Reduction of Flowback Water

There is plenty of reuse capacity until the cycle of hydraulic refractures terminates. The cross-over year improves by only about 1 year. Unless the cost of trucking water dominates the economics during the initial few years of the life cycle of the play, this seems to be a beneficial strategy only during the last few years of active refractures. A deterrent to using the hold-down method is the potential loss of reuse water for the next hydraulic fracture.

Figure 15 is a sensitivity analysis showing the years to capacity and rate cross-over versus fraction of flowback held down-well. In terms of capacity, there is no real benefit to holding water down-hole. This is because the available capacity for each fracture is expended at the initiation of the fracture, regardless of whether the reuse capacity was actually utilized. With large hold-down volumes, there is insufficient recovery of water to meet the reuse demands that arise from the water conservation objectives. The potential benefit accrued in terms of lower transportation costs for recovered water is likely offset by higher transportation costs for obtaining fresh water for the next fracture. The length of time to the crossover of the rate of reuse capacity use and the rate of water collection peaks at just over 18 years. This is because of the large volume of produced water generated by thousands of wells. This water cannot be effectively retained down-well, so that the down-well hold strategy will be effective when the rate refracture diminishes.

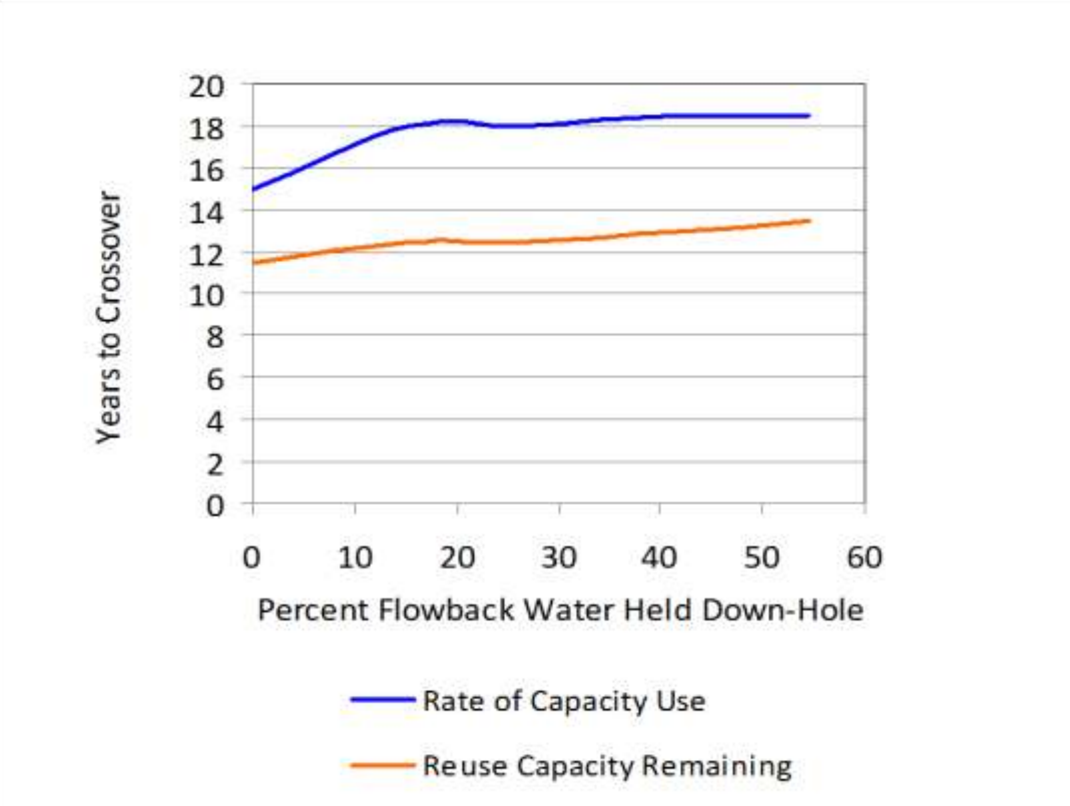

Figure 15: Sensitivity Analysis, Life Cycle Effects of Reducing Flowback Water

5.6 Sensitivity: Interruption of Drilling Schedule and Life Cycle Events

Up to this point, most of the model projections have been based on the assumption that drilling and refracture follow an exact schedule as summarized in Table 3. Uniformity like this is easily modeled, and the projections are easy to describe. Reality dictates, however, that at some time during the 45 year life cycle of the play, this schedule will be disrupted. Economic considerations such as the price of natural gas, labor or equipment shortages, or general economic down-turns, may impact the schedule. Other considerations, such as environmental permitting, mineral rights contracting, or changes in ownership may also impact the drilling schedule.

One attempt to model such a perturbation is presented in Figure 16. The assumption behind this model run was that a one year moratorium on new drilling was enforced during year 10 of the life of the play. All scheduled refractures (at 1000 day intervals, see Table 2) occurred, as planned. The new drilling was resumed after year 11 at a rate similar to year 9. The drilling moratorium in year 10 resulted in a shock wave of future delays in the refracture events for these wells in years in years 13, 16, and 19.

The uniform progression of the life cycle of the play, as presented in the base case, Figure 6, is completely and irrevocably disrupted by the imposed perturbation. While an expert management team might be able to exert control over the remaining years of the play, the economic danger is that water management issues supersede the business of gas production. There is a near collapse of the second crossover point in year 12 and the entire year 14 is a battle to find reuse opportunities for the collected flowback and produced waters. The need for non-reuse options also shows large swings, meaning that companies providing these services are also stressed.

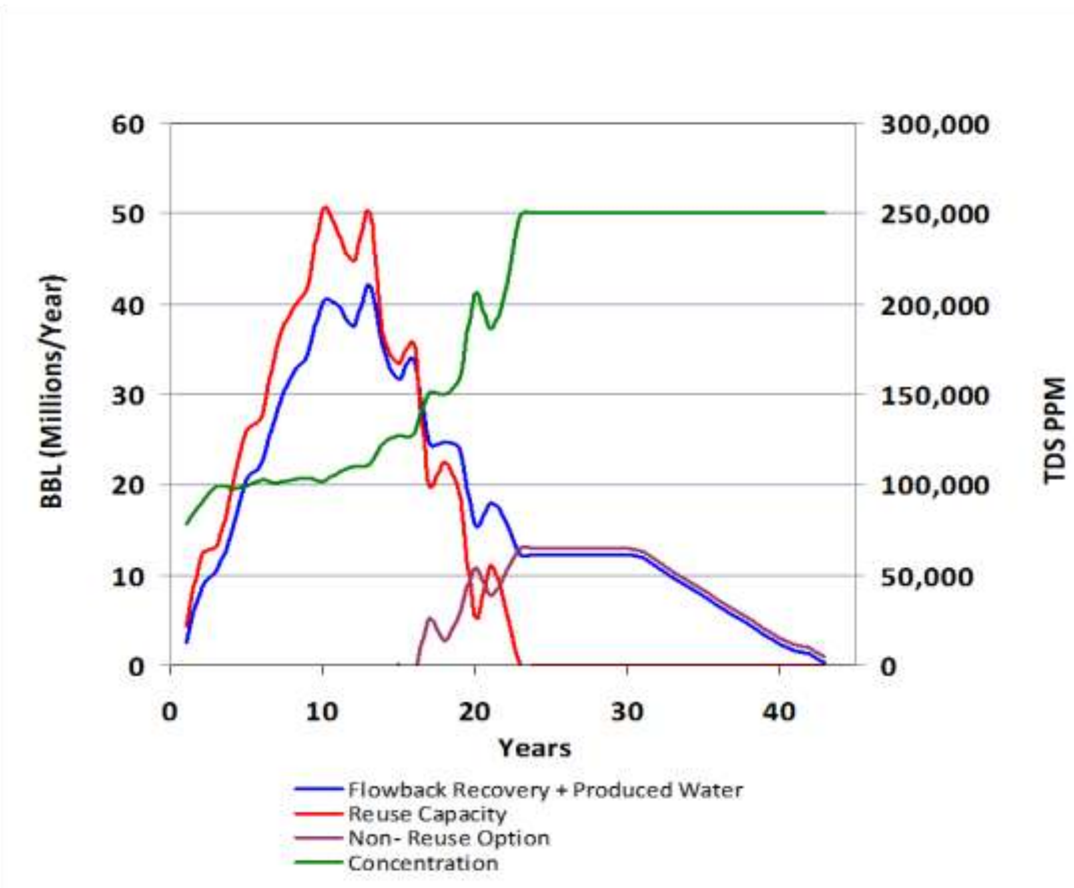

Figure 16: Perturbation of Flowback and Produced Water Recovery Caused by Moratorium on New Well Drilling in Year 10

5.7 *Year- by-Year Indirect Cost Estimates for the Base Case*

The Life Cycle model can be modified to track indirect costs on a year-by-year basis. Hayes and Smith (2011) prepared indirect the cost estimates for carbon footprint, and fuel costs for several management options in the Marcellus. Assumptions and estimated carbon costs for a single case, where all non-reuse water is trucked to a Class II deep well injection facility requiring a 160 mile round trip, are presented in Table 4. These costs are graphically depicted for the development area in Figures 17 through 19 and represent the simple management case. These figures indicate that indirect costs are not constant from year to year. These operational costs grow and then decline along with field activity. In the case of road maintenance alone, these costs may add 6-7% to the annual hauling costs during peak activity.

Table 4: Estimated Carbon Costs per Truck Mile by Flow Scheme (Marcellus Shale)

Miles Traveled per Trip	160
Diesel Used (gal)	21.6
CO_2 Emissions (lb)	480
CO_2 Emissions (ton)	0.240
Carbon Cost per Trip	$6.24
Carbon Cost per Barrel	$0.0524
Carbon Cost per Truck Mile	$0.0390

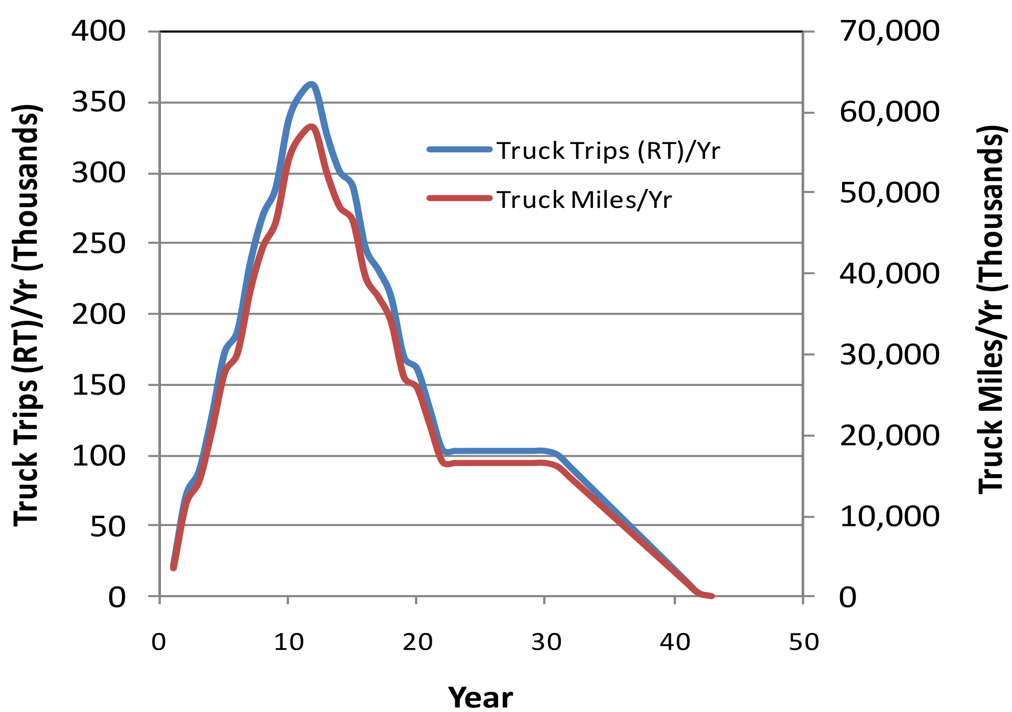

Figure 17: Truck Utilization with Deep Well Injection Off-site

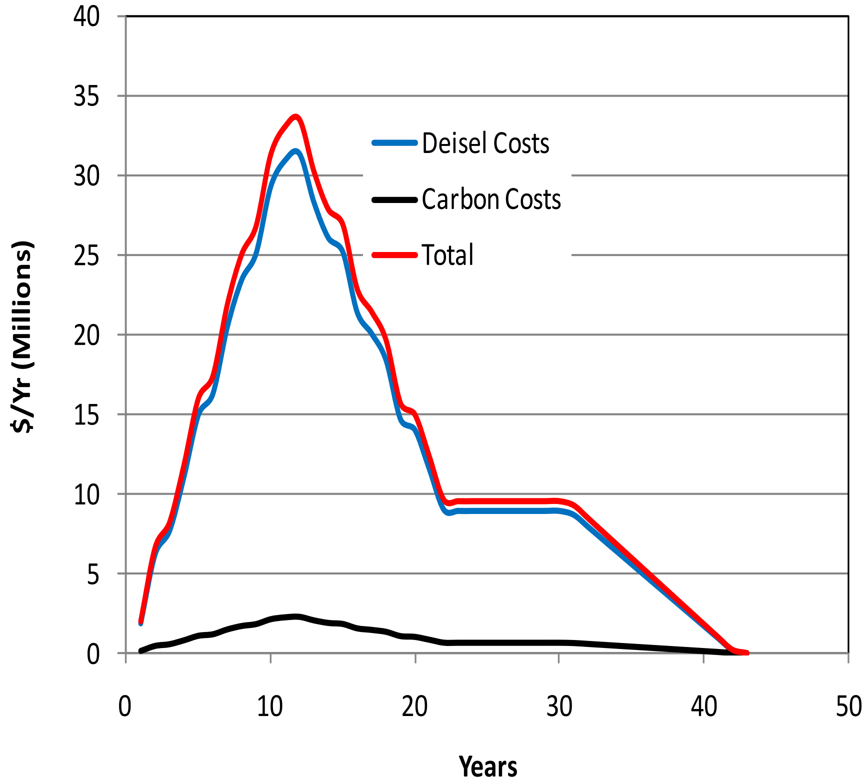

Figure 18: Indirect Costs: Carbon Relative to Diesel

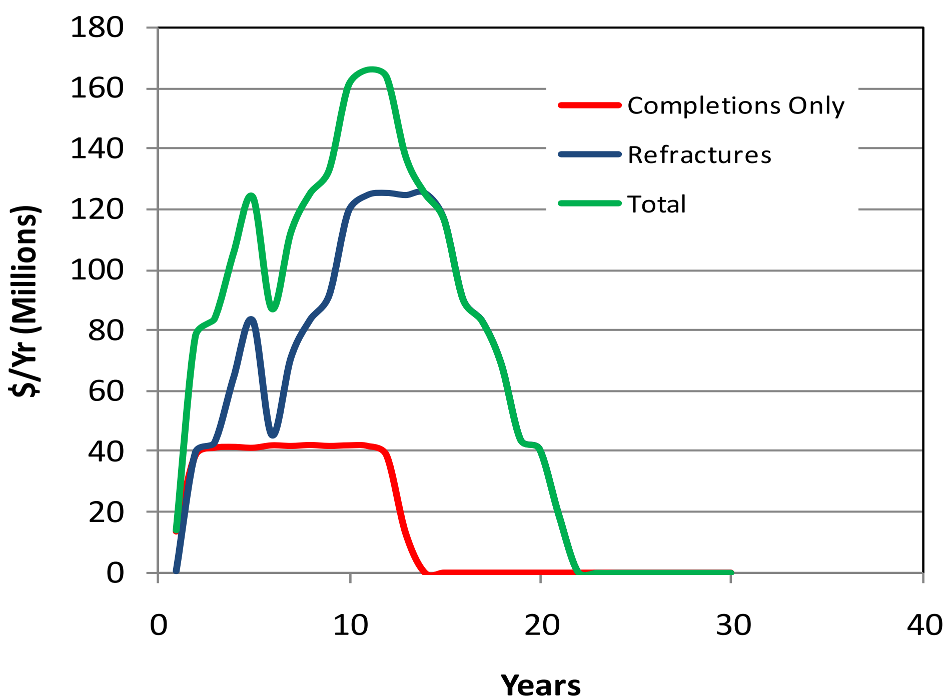

Figure 19: Road Repair

6 Model Results for an Example Development Area in the Barnett Shale (Texas, USA)

Far less information on flowback recovery and salt generation is in the public database for the Barnett than the Marcellus. In a separate research task from this project, an information base on the compositional characteristics of flowback water has been developed on five sites and flow and salinity data have been obtained from twelve sites in the Barnett (Hayes and Severin, 2012).   A preliminary examination of the results for the Barnett versus data for the Marcellus (Table 1) does not indicate overt surprises.

6.1 Definition of the Barnett Case

The median Barnett flowback event is estimated from data presented in Galusky (2011) using the methods generated in Severin, et al (2012, A,B) and Severin and Hayes (2012 C). Figure 20 is a projection of the median early flowback rates and concentrations, as used in the life cycle analysis model.

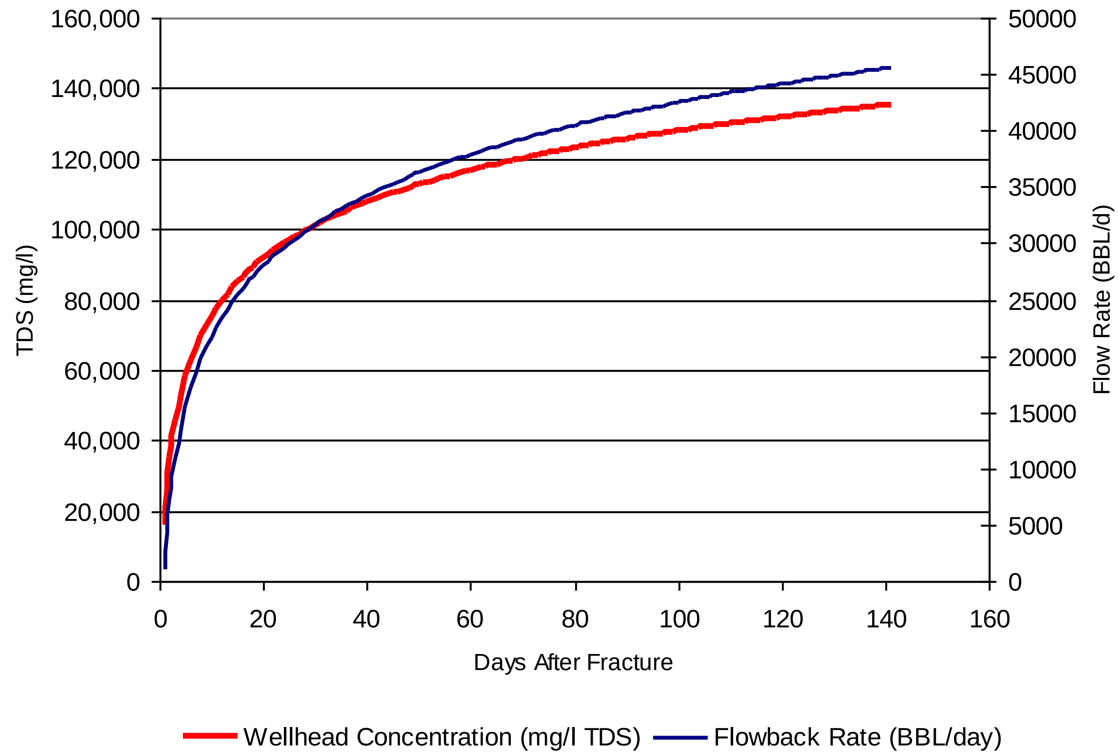

Figure 20: Projection of the Median Barnett Flowback Event Used in the Life Cycle Analysis Model

The early flowback water in the Barnett is typically different than observed in the Marcellus. The Barnet recovery appears to be larger with about double the volume recovered. However, the salt concentration in the Barnet is somewhat lower, trending toward about 175,000 mg/l rather than 250,000 mg/l seen in the Marcellus.

Other geological differences are also important. While the Marcellus has a large availability of surface water for use in the fracture blend, the Barnett has a far lower availability of fresh water. Concerns over possible drought conditions, regulatory restriction on water rights, or a high cost for fresh water will drive innovative development of flowback water reuse as a needed resource. Another difference between the plays concerns the availability of deep well disposal. While there is a dearth of Class II deep-well injection capacity in the Marcellus, there is a plethora of deep-well disposal capacity in the Barnett. The Barnett shale is underlain by highly receptive Ellenburger dolomite strata. A final difference between the two plays is also caused by the underlying Ellenburger strata beneath the Barnett. Some communication of a modest flow of brackish water from the Ellenburger stratum into the Barnett may occur with hydraulic fracturing, making the long term production of produced water slightly higher (around 15 barrels per well per day in the Barnett) than encountered in the Marcellus (around 7 barrels per day per well).

6.2 Model Results from the Barnett

The operational strategy presently utilized in the Barnett is to capture about 10% of the early flowback water. The remainder (90% of the flowback) plus produced water is usually deep well injected. The base case for the present discussion of the Barnett (Figure 21) follows closely the parameters laid out in Table 2, with the exceptions that the produced water flow is 15 barrel per day per well and that only 10% of the flowback is reused. The results in this figure are quite different from the results for the Marcellus (Figure 6). The curves for non-reuse options and reuse options are essentially flipped between the two figures. By the definitions of cross-over events, the capacity for reuse in the Barnett is exceeded by the recovered water on the day of the first fracture. In terms of the age of the play, based on cross-over years, the Barnett plays are in middle-age from the start. The development of non-reuse options (e.g., deep-well injection) must continually parallel the drilling and refracture regime. After 22 years, there is no reuse available and a constant rate of about 26 million barrels/ year is still generated. This requires a constant development of deep well injection capacity. The Barnett play enters old age at year 22. From year 22 to year 30, there is a constant collection of produced water totaling about 25 million barrels per year from the 4800 wells. In years 30 to 45, there is a constant decrease in produced water generation as the wells are closed-in.

Because the reuse option is only about 10% of the water management plan, the need for non-reuse options is very large. Figure 22 shows the projected produced water recovery and salt generation versus a range of potential produced water collection between 1 and 25 barrels/day. Regardless of the rate of produced water recovery assumed, there is a substantial need for non-reuse capacity.

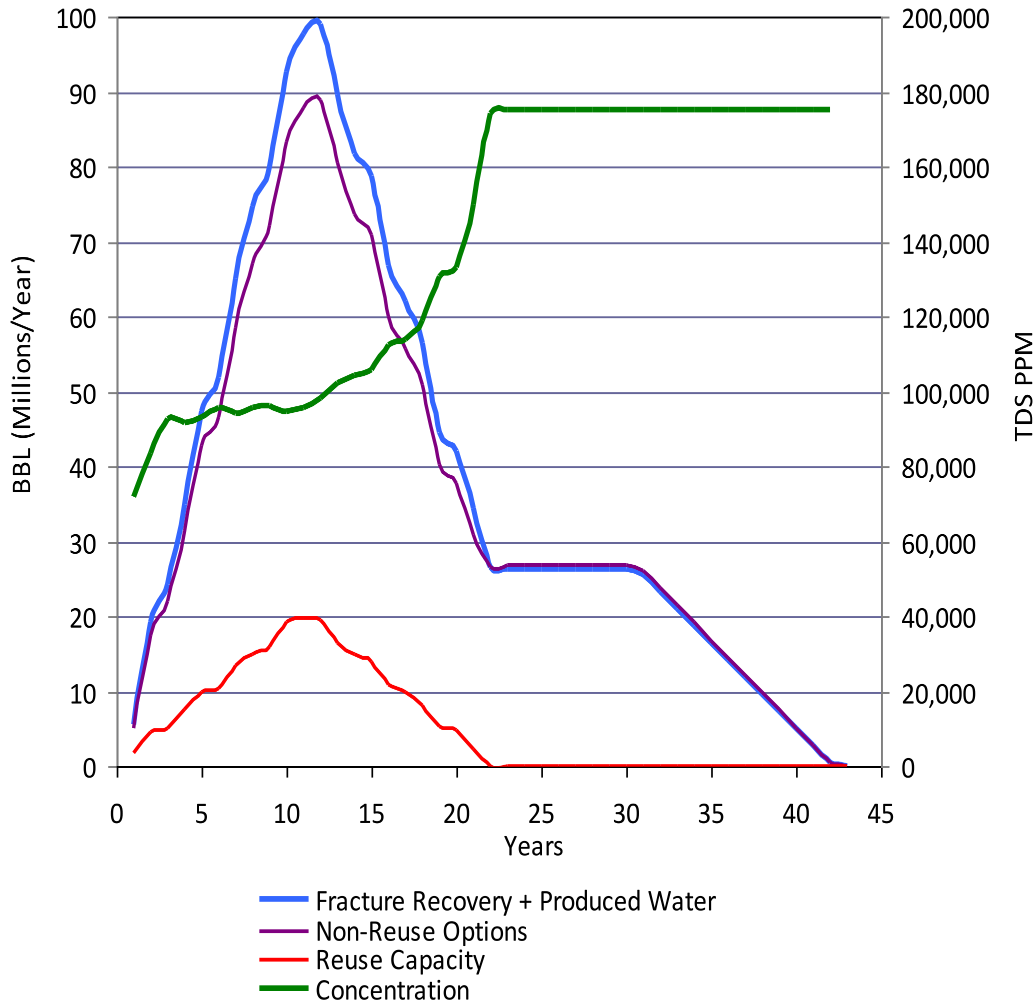

Figure 21: Water Recover and Non-Reuse Option Capacity for the Barnett Assuming 4800 wells with 19,200 Fractures, 10% Water Reuse, 15 bbl/day Produced Water Recovery

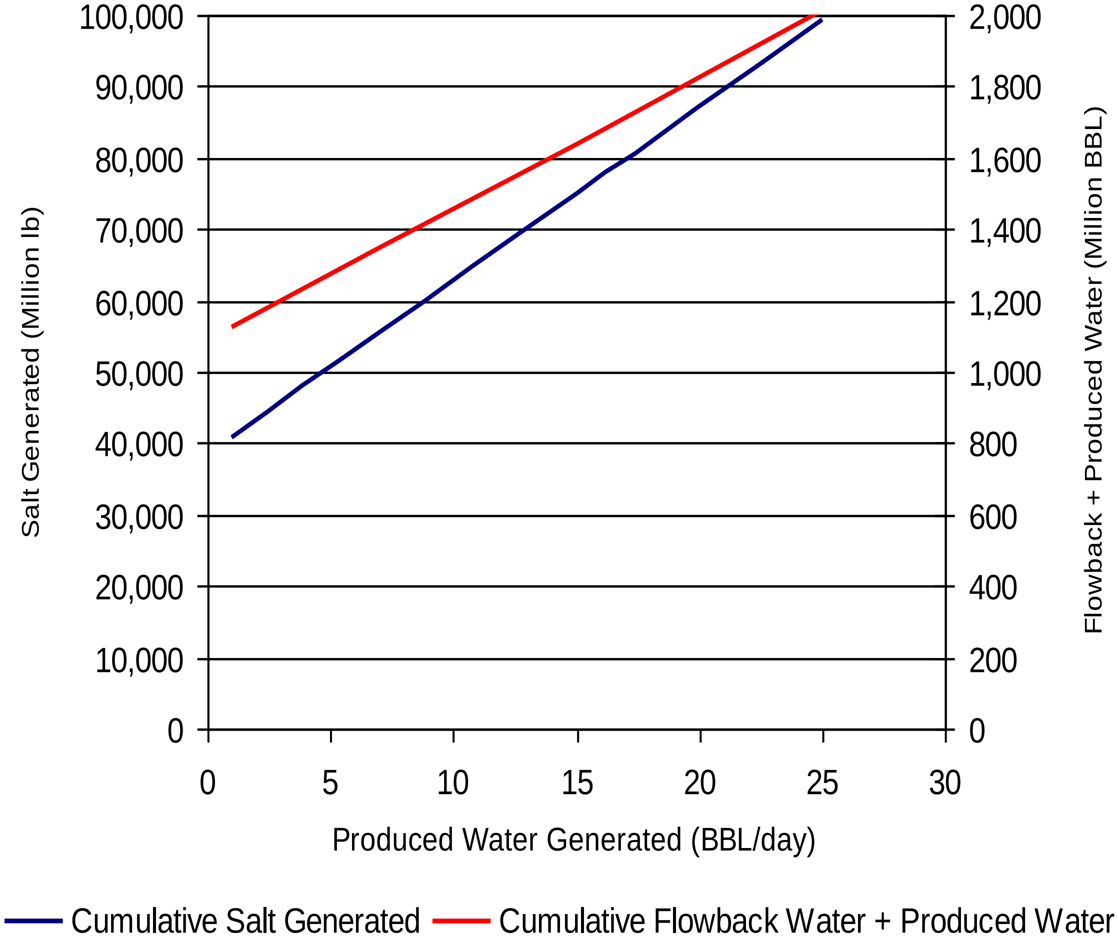

Figure 22: Magnitude of Total Flowback + Produced Water and Salt Generated During a 45 Year Life Cycle of
A Barnett Play with 4800 Wells

7 Discussion

7.1 The Marcellus Shale

A simple life cycle analysis of the water management issues in the Marcellus demonstrates that there are clear and definable periods in the process needs throughout the projected 45-60 year life of each play. Within the Marcellus, there is a large dependency on water reuse due to a lack of deep-well injection alternatives, and this dependency will be a major driver in all decisions concerning water management.

Water management issues must first be viewed from the needs of the individual well. Initial high volume fracture and subsequent refractures will be followed by intervening periods of low flow from produced water recovery. The first challenge will be the design of pipes, pumps, and storage capacity that can handle a large range of daily flows from several thousand barrels/day down to 5-15 barrels/day. If flowback water and produced waters are collected for reuse without regard to the elevated concentrations of salts which can range from 60,000 to 250,000 mg/l, high integrity, no-leak conveyance and storage will be required which will add considerable cost to water management. Some of this cost can be avoided through the separate management of low-TDS early flowback water and/or demineralization of the brines with the objective of recovering more than 70 percent of the water content as a demineralized stream for water reuse.

With multiple wells in the field, scheduling the recovery and reuse of the water from one well to another may necessitate refinement of the water management infrastructure to a higher level than for individual wells. When the final well in the field is completed, the period of sequential recovery of high volume flowback water is temporarily ended for the field. What follows is a low volume bleed-back of highly concentrated produced water from a multiple of wells. At some time in the future, the field will likely undergo refracture. The need for the high volume capacity equipment will return. Decisions on the mobility of the high volume equipment and the long term maintenance of the low volume equipment will need to be made.

With the scheduling of development of multiple fields within the play, the water management issues of the individual well and within the individual field are amplified. The Marcellus has an early period in the first 11 years in which the water management axiom of "putting it all back down-hole" *may* be a viable option. The treatment needs can be kept local, with only enough water treatment to make the recovered water palatable for blending and reuse in the next fracture. However, there is a risk that economic or regulatory changes can result in an activity slow-down at any point. Without contingencies in place, the reliance on "putting it all back down hole" can cause a near-term crisis in water handling.

Between year 11.5 and year 15, the easy reuse of recovered water ends and the play enters a mid-life crisis. The drilling is done, and the final refractures are scheduled. Unfortunately, the produced water keeps coming. The larger the portion of produced water in the total recovery, the more difficult it will be to make it compatible for reuse. Finding the next fracture to expend the reuse water will become difficult. One company may find itself in the position of paying its competitor to dispose of the excess water.

After year 15, there are no more fractures scheduled to use up the recovered water. At this point the play is in an old age crisis. The produced water keeps coming and there is no place to put it. Expensive transportation and disposal costs or resource recovery must be implemented. Early retirement of the less fully productive wells becomes a necessity to minimize the impact of the produced water.

7.2 The Barnett Shale

The current situation in the Barnet is that the majority of the recovered flowback water is deep well injected. At about 15 years into the life of the play, the drilling and refracturing activities end. Yet the produced water keeps coming. The challenge will be to keep developing disposal capacity and other alternatives in parallel with the development of the play.

In a region, such as the Barnett, with limited water resouces, it is easy to foresee increased competition for fresh water with increased regulatory challenges (water rights restrictions, mandated water management practices, etc.). Water treatment alternatives will need to be engineered. Consistent with this vision, a number of developer companies in the Barnett have initiated the testing of various processes for brine conditioning and reuse to have access to these “hedge” technologies and tools for address future challenges associated with each shale gas development area life cycle within the Barnett Region.

8 Conclusion

Life cycle analysis of water management issues in shale gas plays is in its infancy. Few data on the chemical character and flow profile from flowback are available from the Marcellus, and even less from the Barnett. Yet even simplistic projections show that there is a real possibility that water management issues will dictate most of the important decisions in a life of a play. Water management has the potential to dictate how many wells are drilled, the number of refractures planned, the periodicity of the refractures, the need and desirability to reuse recovered water, and ultimately the close-in date of individual wells. This infers that management, economic, and engineering decisions concerning the play should be considered before the first well is drilled.

The life cycle and the major events in each play will be unique. It is seen in this simple analysis that the water management concerns in the Marcellus are different than in the Barnett. These operational profiles may be taken into account in the fine tuning of a life cycle analysis and will yield different projections.

To date, only simple economic evaluations have been incorporated into the life cycle analysis. As more information is gathered, and more treatment/reuse options are developed, the model has the potential to yield critical projections for engineering and business decisions throughout the life of a play.

The modeling exercise in this preliminary systems analysis has yielded insight into the life cycle of multiple-well, multiple field, gas plays. The life of a play may be conceptually divided into youth, middle-age, and old-age. This analysis provides preliminary insight into the types of problems that may be encountered at different times. This suggests that a series of different engineered solutions to water management will be needed throughout the life of the play.

The water management issues are at first relatively straight forward. Much of the flowback water may be immediately reused. The play is in its youth and each new fracture becomes a repository for the recovered flowback water from previous fracture events. Removal of suspended solids with blending with fresh water may be sufficient to create a steady source of water for new fractures.

At some point several years after the first completions, however, the rate of fracture events slows. The projected volume of flowback and process water exceeds the projected capacity to handle the volumes generated. For this period, an astute water manager may be able to juggle an ever tightening differential between generation and reuse. The play is middle-aged. Water treatment may include on-site or regional desalination to generate sufficient water to replace fresh water sources in any new fractures. Salts are concentrated to minimize volume disposal of non-reusable water.

As the play ages further, new fractures become infrequent. The rate of process water generation dominates the management decisions. More water is generated on a daily basis than can be beneficially reused. The play is old-aged. Engineered solutions may include complete reliance on disposal of all water, or treatment options may favor permitted discharge to surface water with desalination to minimize deep well injection costs. Failure to plan for water management issues in old-aged plays will result in pre-mature closing of productive well.

9 References

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Severin, B.F., Galusky, L.P,Jr., and Hayes, T,D., (2012B) Empirical Interpretation of Barnett and Marcellus Flowback Events: Part II, Brine Profiles

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10 Appendix A. Correlation Methods

Twelve data sets from Table 1 contain both flow and concentration data. These sets were interpolated to better understand the relation between flow and concentration. Data sets not considered for further analysis had insufficient completeness to attempt further analysis. The data sets not developed are highlighted in gray.

All correlations were generated using the Microsoft Excel function, LINEST() which generates the slope, intercept, and regression (r^2).

The relationship that best fits the volumetric data is Equation 1 where V (barrels) is the total volume collected from day zero to day (X). Figure A1 is an example of three flowback events showing total volume versus time.

1. $V = a\ln(X) + b$

The relationship that best fits the concentration data is Equation 2 where TDS (PPM) is the well head concentration on Day. Figure A2 is an example of three flowback events showing well head concentration versus time.

2. $TDS = c\ln(X) + d$

Values for a, b, c, and d for the 12 flowback events are presented in Table A1.

Neglecting small specific volume changes at high salt concentrations, the total mass of salt collected (pounds) is a function of the total volume collected and the well head concentration, and can be calculated as a numerical integration between any volumes (Equation 3); where K = 42 gal/barrel x 8.34 lb/gal x 10^{-6}.

3. $\sum_{i}^{i+1} M \cong K\left(V_{i+1} - V_i\right)\left(\frac{TDS_i + TDS_{i+1}}{2}\right)$

Table A2 is a summary of projected flowback volumes and total salt production. In three cases (Table A1) correlations yield negative flows on day 1. In these cases, the initial values for the day 1 volumes were replaced with the actual reported values. Otherwise, the total mass of salt was calculated as per equation 3 based on interpolated results from equations 1 and 2.

The development of Table A2 (or similar time frame) allows for development of the relation between total volume and total mass of salt collected. Figure 3 follows the development for all twelve flowback events.

Figure A3 shows that most of the flowback events (8 of 12) yield strikingly similar profiles of total mass of salt collected versus total water collected. Figure A4 shows the other four events. Two events (G and H) are initially higher starting concentrations and more rapid salt generation than the results in Figure A3. Site E showed a lower salt collection for the given volume of flowback water. Examination of the Site E data indicates that it was the highest day 1 flowback volume of all the sites. Site K is a bit anomalous in that the salt concentration decreased with time after fracture. A more detailed analysis of the flowback events may yield important information, such as hold time prior to release, that could have bearing on better predictive models.

Individual sites tend to show a slower flowback rate with increased time, which is a reasonable prediction since water availability and back pressure both decrease with as the flowback volume increases. It is also reasonable that salt recovery should show a higher salt concentration as the time of subsurface exposure increases. Surprisingly, eight of twelve events show remarkably similar salt versus volume profiles.

Table A1: Correlation Constants for Twelve Marcellus Shale Events (See Equations 1 and 2)

Site	A	b	r^2	c	d	r^2
A	4182	3887	0.999	33119	11498	0.956
B	3651	2887	0.929	37449	22145	0.992
C	4730	2952	0.984	31513	20906	0.916
D	1823	4026	0.878	33357	727	0.977
E	3753	11586	0.815	44709	-2652	0.958
F	3040	4314	0.960	36103	60272	0.998
G	8623	-7913	0.935	35379	72765	0.994
H	6653	4458	0.986	71705	23521	0.996
K	1410	5750	1.000	-4252	26358	0.096
N	247	2401	0.995	43722	35682	NA
Q	1428	1305	0.999	36932	6064	0.812
S	1867	3416	0.862	45768	-3822	0.973

Table A2: Salt Recovery Data Interpolated from Correlated Data for 12 Marcellus Events

TOTAL VOLUME (Barrels) RECOVERED to DAY						
	1	5	14	21	38	45
Site	3,900	10,600	14,900	16,600	19,100	19,800
A	2,900	8,800	12,500	14,000	16,200	16,800
B	3,000	10,600	15,400	17,400	20,200	21,000
C	4,000	7,000	8,800	9,600	10,700	11,000
D	11,600	17,600	21,500	23,000	25,200	25,900
E	4,300	9,200	12,300	13,600	15,400	15,900
F	1,200	6,000	14,800	18,300	23,500	24,900
G	4,500	15,200	22,000	24,700	28,700	29,800
H	5,700	8,000	9,500	10,000	10,900	11,100
K	2,400	2,800	3,100	3,200	3,300	3,300
N	1,300	3,600	5,100	5,700	6,500	6,700
Q	3,400	6,400	8,300	9,100	10,200	10,500

TOTAL SALT (lb) COLLECTED to DAY						
Site	1	5	14	21	38	45
A	15,700	105,600	229,100	291,800	397,900	431,300
B	22,400	130,000	263,900	330,600	442,200	477,200
C	21,600	145,000	294,800	369,000	493,000	531,700
D	1,000	29,400	76,400	101,200	143,600	157,100
E	12,200	88,700	213,600	280,000	394,400	430,800
F	91,100	244,100	394,300	464,600	578,800	613,900
G	31,100	199,400	659,400	871,700	1,213,700	1,318,200
H	36,700	341,400	763,300	978,100	1,341,700	1,456,200
K	53,100	71,300	80,100	83,000	86,500	87,400
N	30,000	39,900	51,400	57,000	66,300	69,200
Q	2,800	31,600	75,100	97,600	136,000	148,200
S	1,400	38,800	101,700	135,200	193,000	211,400

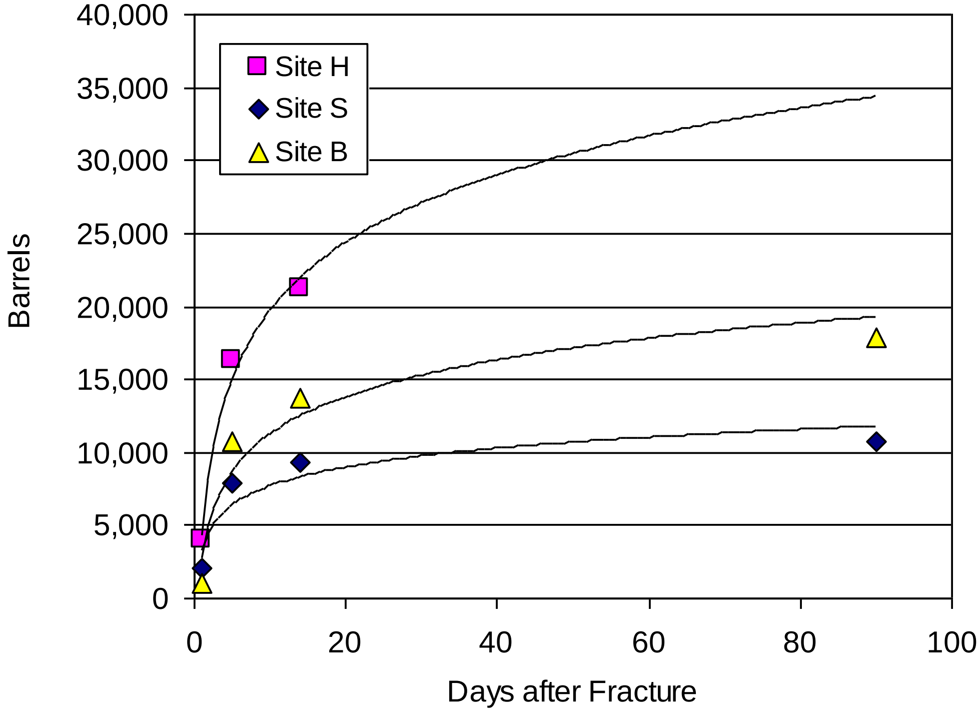

Figure A1: Example of Flowback Volumes at Three Marcellus Wells

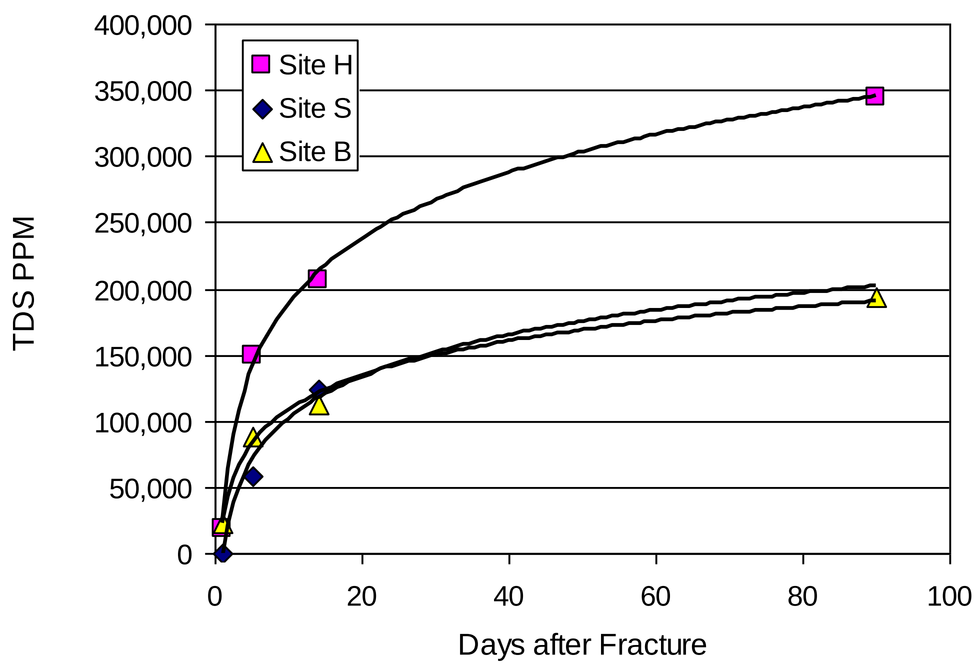

Figure A2: Example of Well Head Concentrations at Three Marcellus Wells

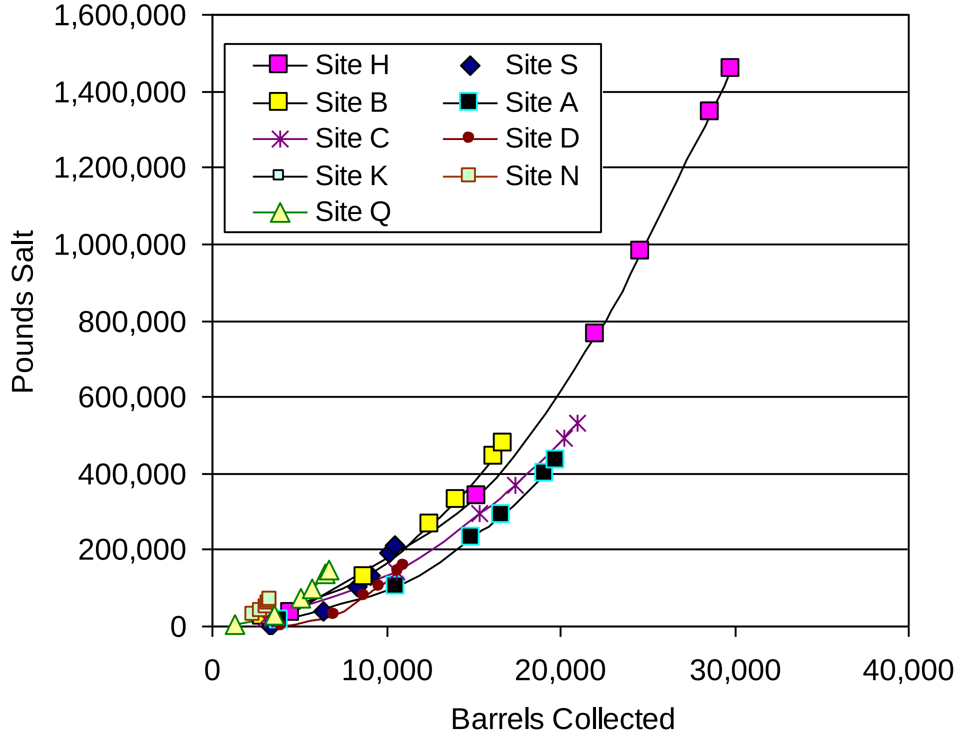

Figure A3: Correlation of Salt Mass Generated at 8 Marcellus Wells

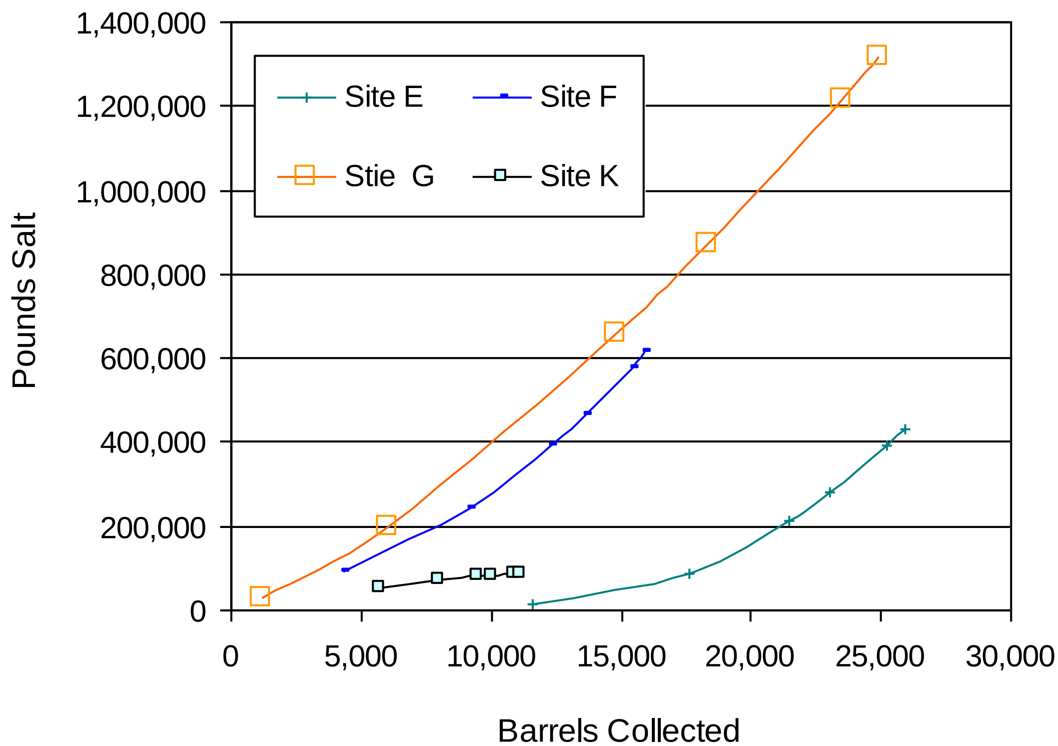

Figure A4: Range of Salt Generation at Four Marcellus Wells

11 Appendix B. Modeling Down-hole Hold Time

One of the potential water management strategies to be examined is the mitigation of the flowback event by increasing the down well hold time before the release of the flowback water.

Authors' Note: The following approach is based on an intellectual incursion into a technical area in which there is, at best, only anecdotal evidence. It remains a work-in-progress. Because each fracture event is different, there is no control test that can ever be made in which both events, holding the water down-hole or releasing the water immediately can ever be directly tested. The best that can be accomplished is sequential tests between sister wells in the same field.

The approach to approximating the effect of hold time is based on two fundamental engineering principles 1) the rate of water flowback is dependent on the available pressure of the flowback water and 2) the rate of flowback is dependent on the available volume of flowback water. A logical extension of these concepts is the assumption that the available pressure is a function of the available volume. As such, one can envision that the effect of down-hole hold time on a typical flowback curve would be to shift the origins of the axes. The new X axis represents a function of the number of down-hole days. This is not necessarily a 1:1 correlation. For example, ten down-hole days will likely not be equivalent to ten days on the original curve. The new Y axis initiates at zero volume. The new flow curve would then follow the same trajectory as the original flow curve, as in Figure B1.

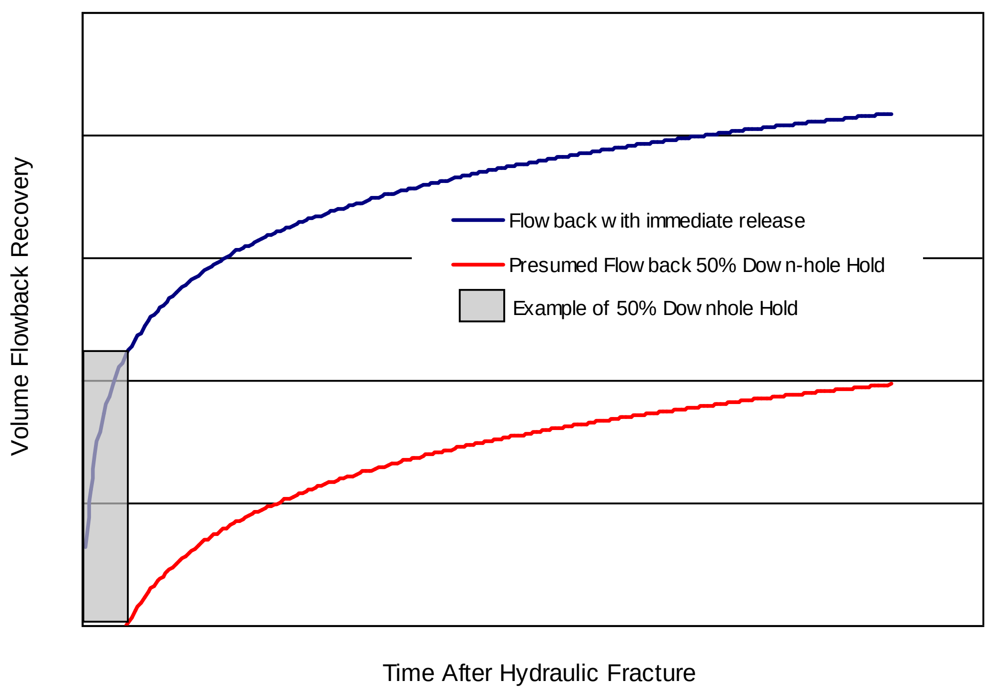

Figure B1: Conceptual Development of an Approximation of Down-hole Hold Time on Flowback Recovery.

The question of the equivalence of the equality between down-hole hold time and time after fracture in the original flowback curve can be, at least partially avoided. This is accomplished by consideration of the fraction of the original flowback held down-hole. Consider again Equation A1 (repeated herein as B1) in which the total volume of flowback recovered, V(barrels) is a function of the days after the fracture event, X (days). In this report, the total recovery of flowback water is an extrapolation to 180 days after the fracture event (X=180). If a claim is made that 30% of the flowback volume can be retained down-hole, then the equivalent days down-hole, (X_{dhe}), can be calculated.

$$B1.\ V = a\ln(X) + b$$

$$V_{180} = a\ln(180) + b$$

$$0.3V_{180} = a\ln(X_{dhe}) + b$$

The systems model can then be based on a claim of the fraction of flowback water retained, as opposed to a claim of hold-time required to accomplish this feat. By virtue of the assumption that the trajectory of the flowback volume curve is continuous (Figure B1), then the equivalent days down-hole, X_{dhe}, can be used to calculate the flowback event with an effective down-hole delay. However, the volume of flowback water recovered is reported based on an approximate fraction volume retention.

Down-hole hold time would be expected to increase the salinity of the flowback water. The conservative approach is taken in this model. The salinity of a held water on is assumed to be the same as encountered in a flowback with an age of X_{dhe} days. For example, if the equivalent hold time is 14 days, then the salinity of the first water emerging up-well would reflect the salinity of flowback water at day 14 from the original curves.