Oil & Natural Gas Technology

DOE Award No.: DE-FE0001243

Clean and Secure Energy from Domestic Oil Shale and Oil Sands Resources

Quarterly Progress Report (January – March 2015)

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Prepared for:
United States Department of Energy
National Energy Technology Laboratory

May 6, 2015

Office of Fossil Energy

Acknowledgment: "This material is based upon work supported by the Department of Energy under Award Number DE-FE0001243."

EXECUTIVE SUMMARY

The Clean and Secure Energy from Domestic Oil Shale and Oil Sands Resources program, part of the research agenda of the Institute for Clean and Secure Energy (ICSE) at the University of Utah, is focused on engineering, scientific, and legal research surrounding the development of these resources in Utah.

Outreach efforts in Task 2 focused on finishing up the transition of the ICSE unconventional fuels repository to the Institutional Repository maintained and managed by the University of Utah.

Task 3 focuses on utilization of oil shale and oil sands resources with CO_2 management. The Subtask 3.3 and 3.4 teams finalized the emission factors and their ranges for oil and gas operations in the Uinta Basin. They also made three improvements to their conventional oil and gas simulation model: (1) switched to a cumulative production equation for predicting oil and gas production, (2) developed a method for forecasting oil and gas price paths based on EIA's Annual Energy Outlook price forecasts and the forecasting error, (3) added capability to model production from existing wells.

Task 5 and 6 projects relate to environmental, legal, economic, and policy analysis. All Task 5 and 6 projects are now complete.

Task 4 and 7 projects are related to liquid fuel production by in-situ thermal processing of oil shale. For Subtasks 4.8 and 7.1, numerical simulations of the triaxial testing were performed and the development of a computational methodology for simulation of subsidence and compaction associated with in-situ pyrolysis of oil shale continued. In addition, the permeability and porosity of rich and lean oil shale samples from the Green River Formation were measured before and after pyrolysis. The Subtask 4.1 and 7.3 team modified their simulation geometry, which allowed them to run an optimization study to determine an optimum design for well arrangement. This design maximizes the net energy return by maximizing oil production and minimizing the number of wells drilled. They also accomplished their milestone of implementing kinetic models in their simulations.

PROGRESS, RESULTS, AND DISCUSSION

Task 1.0 - Project Management and Planning

There were no schedule/cost variances or other situations requiring updating/amending of the Project Management Plan (PMP) in this quarter.

Task 2.0 -Technology Transfer and Outreach

Technology transfer and outreach efforts are focused on communicating project results through publication of papers and reports, through visits and interviews, and through updates of the program website. During this quarter, work continued on transitioning the unconventional fuels repository of documents, maps, and figures relating to oil shale and oil sands to the University of Utah Institutional Repository (IR). The IR will maintain the collection once the project period has ended.

Task 3.0 - Clean Oil Shale and Oil Sands Utilization with CO_2 Management

<u>Subtask 3.1 – Lifecycle Greenhouse Gas Analysis of Conventional Oil and Gas Development in the Uinta Basin (PI: Kerry Kelly, David Pershing)</u>

During this quarter, the team finalized the emission factors and their ranges for oil and gas operations in the Uinta Basin. These factors include the effects and timing of the federal New Source Performance Standards (NSPS) (see Table 1) and new state regulations. Team members also completed their contributions to the joint publication on the impacts of oil and gas development in the Uinta Basin and began work on their chapter in the upcoming oil shale book.

Table 1. Change in emission factors for CO_{2e}, CH_4 and VOCs after the NSPS implementation for new wells (NETL, 2014). The beginning dates are the effective dates of NSPS.[1]

	CO_{2e} (%)	CH_4 (%)	VOCs (%)	Beginning
Construction	+2	-	-	January, 2015
Completion	-96	-96	-96	January, 2015
Production	-66	-66	-66	November, 2012
Processing	-20	-40[2]	-40[2]	November, 2012
Transport[3]	-0.5	-0.5	-0.5	November, 2012

[1] Some of the categories, such as production, encompass several activities, such as pneumatic controllers and workovers. In this case the beginning date is the date of the largest contributor to the category.
[2] Based on the NETL (2014) data. Value assumes that emissions from other point sources and valve fugitives are mainly due to methane.
[3] Based on the NETL (2014) data. Methane emitted due pipeline construction was not included.

Beginning in 2015, new state rules require the replacement of existing high-bleed pneumatic control devices with low-bleed devices. For production activities occurring on state and federal lands, this rule will result in a 50% reduction in VOC/CH_4 emissions in Duschene County and a 27% reduction in VOC/CH_4 emissions in Uintah County, respectively. The two counties have different contributions from gas-well dehydrators, and this difference is the main cause of the different reduction percentages in the two counties. Wells located on tribal lands are not subject to this rule. Overall these rules will result in a 1.2% reduction in VOC/CH_4 emissions in Uintah and an 11% reduction in VOC/CH_4 emissions in Duchesne County, respectively, from production activities for exiting wells. These reduction percentages include tribal lands. Uintah County has more pneumatic controllers located on Indian lands; consequently the reduction is lower.

Subtask 3.2 - Flameless Oxy-gas Process Heaters for Efficient CO_2 Capture (PI: Jennifer Spinti)

The project team will be submitting a final report at the end of the next quarter.

Subtask 3.3 - Development of Oil and Gas Production Modules for CLEAR$_{uff}$ (PI: Terry Ring)

Over the first quarter of 2015, Subtask 3.3 and 3.4 researchers primarily focused on making the following refinements to the conventional oil and gas simulation model:

- Switching to a cumulative production equation for predicting oil and gas production
- Developing a new method for forecasting oil and gas price paths based on EIA's Annual Energy Outlook price forecasts (and its forecasting error)
- Adding a module that computes production from existing wells

Cumulative Production

A key premise in the team's Monte-Carlo (MC) modeling approach is that most model parameters can be randomly and independently selected from cumulative distribution functions (CDF). A prime example are the three fitted coefficients q_o, b, and D_i in the hyperbolic decline curve equation:

$$q(t) = q_o(1 + bD_it)^{(-1/b)} \quad (1)$$

where q is the oil or gas production rate at time t (in months), q_o is the initial production rate, b is the decline exponent, and D_i is the initial decline rate. These three coefficients were fitted to every well in the Uinta Basin for which production records were available, and the resulting data points were used to generate CDFs. During a simulation, random draws from these CDFs provide the values for q_o, b, and D_i of the simulated wells. In the aggregate, this approach produces simulated total oil and gas production values which match actual total production records. However, closer inspection of the individual decline curves for each simulated well revealed that many wells had unrealistic combinations of decline curve coefficient values. For example, the largest oil field in the Uinta Basin, Monument Butte, has the following range of coefficients values:

Table 2. Hyperbolic decline curve coefficient statistics for oil production from wells located in Monument Butte (1,007 wells).

Coefficient	q_o	b	D_i
Minimum	153.400e+0	5.176e-7	5.071e-3
1st Qtr.	4.932e+3	0.933e+0	0.774e+0
Median	173.200e+3	1.261e+0	1.894e+3
Mean	68.520e+6	1.396e+0	15.400e+3
3rd Qtr.	3.394e+6	1.613e+0	9.142e+3
Maximum	8.704e+09	10.000e+0	604.900e+3

Assuming that the model randomly selected the median values for each coefficient for a simulated well in this field, then the monthly oil production after five years ($t = 60$) would be 14 barrels (bbl), a low but reasonable number for a well in that field. However, suppose instead that the randomly selected value were $q_o = 173.2e3$, $b = 1.613$, and $D_i = 0.774$, which are the median, 3rd quartile, and 1st quartile of q_o, b, and D_i, respectively (a very likely pick, given the number of wells simulated). The production for a well with those coefficients after five years would be 12,000 barrels per month, which is two orders of magnitude larger than both the mean and median production for wells in Monument Butte after five years. It's just as easy to pick coefficients that lead to no production, ever, and overall about one-third of the wells simulated had essentially zero production at every time step. Ultimately, the problem with using Equation (1) to estimate production for new wells with randomly and independently selected decline curve coefficients is that the range of possible values is so large (up to nine orders of magnitude) that the model is unlikely to pick combinations that give reasonable results.

After testing several alternative methods for addressing the coefficient selection problem, the research team decided to fit production data to the following cumulative production equation:

$$Q(t) = C_p \sqrt{t} + c_1 \qquad (2)$$

where Q is the cumulative production of oil or gas at time t (in months) and both C_p and c_1 are fitted constants. Equation (2) is a semi-analytic solution of Darcy's Law for reservoir flow in the linear flow regime (which is representative of the early production period for most hydraulically-fractured wells), and was selected after consulting with Ian Walton of the University of Utah's Energy and Geoscience Institute (EGI) (Walton, 2012). The primary advantages with Equation (2) are firstly, that it is just as successful at fitting production records as Equation (1), and secondly, that since monthly production is calculated from Equation (2) by difference, essentially the only coefficient that impacts production values for a well is the value of C_p, which eliminates the problems encountered with random and independent coefficient selection. An example of cumulative production decline curve fit is shown below in Figure 1.

Energy Price Path Forecasting with EIA Annual Energy Outlook and Error Propagation
Another major change made to the conventional oil and gas simulation model this quarter was the inclusion of a new method for predicting energy price paths. Since the model uses energy prices to predict the number of wells drilled, and hence the total amount of oil and gas produced, energy prices are one of the greatest sources of uncertainty. Previous versions of our model have used Geometric Brownian Motion (GBM) price models for forecasting oil and gas price paths during the simulation period. However, given the widespread use and acceptance of EIA's Annual Energy Outlook (AEO) for forecasting oil and gas prices, an option for randomly generating price paths based on the AEO was added in this quarter.

Researchers began by reviewing the error between AEO predictions of wellhead oil and gas prices in the Rocky Mountain region with actual oil and gas wellhead prices

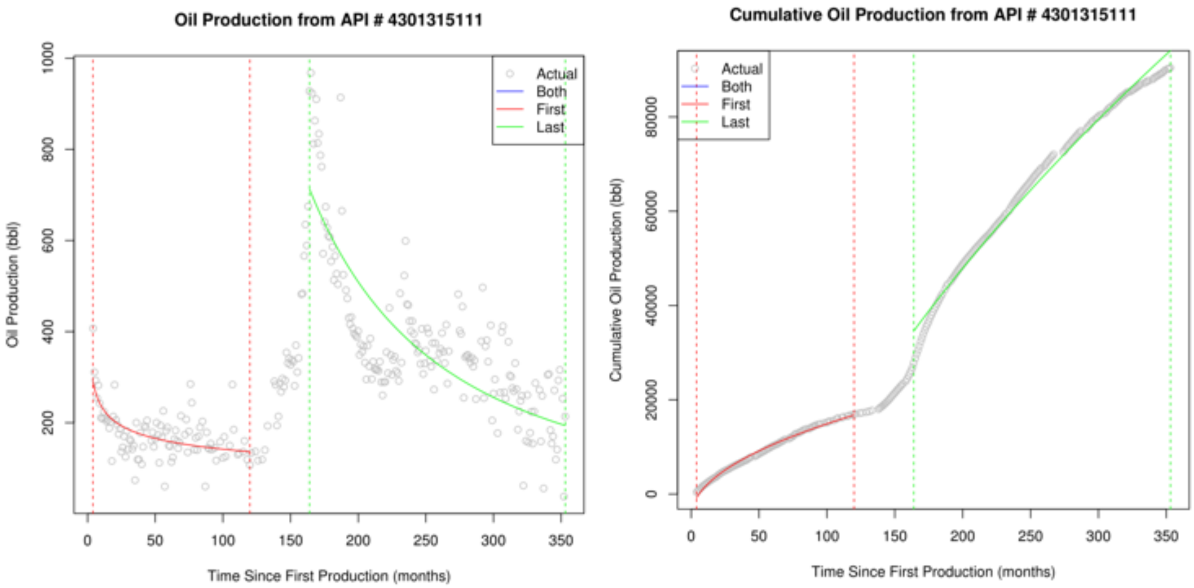

Figure 1. Comparison of hyperbolic (Equation (1)) and cumulative (Equation (2)) fits of the production record from an oil well in the Monument Butte field.

every year for which AEO forecasts were available (see Table 3). These values were used to generate CDFs for error propagation using the formula:

$$F(t) = P(t) \bullet [1 - E(t)] \quad (3)$$

where *F* is the adjusted forecast, *P* is the original forecast, and *E* is the error percentage, all at time *t*. The algorithm used for implementing Equation (3) is:

1. Randomly select quantile for *E*, for example, the 50^{th} percentile (i.e. median)
2. Get value of *E* at each time step at that interval. Continuing the above example, median *E* values for oil are -8%, -26%, -35%, -55%, -74%, … for years 1, 2, 3, 4, 5, …
3. Interpolate *E* and *P* on a monthly basis, then calculate *F*

The result of using this method for generating price oil price forecasts is shown in Figure 2.

Production from Existing Wells

The last major feature added to the conventional oil and gas simulation model this quarter was a method for calculating the production from existing oil and gas wells. As illustrated in Figure 1, the decline curve analysis (DCA) algorithm identifies the “first” and “last” decline curve segments for each well. By also noting the age of each well at the start of the simulation period, the last decline curve fit can be used to extrapolate production. After comparing the predictions from Equations (1) and (2) for wells producing at long times (months), researchers concluded that the hyperbolic decline curve was more successful at matching production records than the cumulative production equation. Since new coefficients are not being picked randomly, the use of Equation (1) posed no problems and was selected for this population of wells.

Table 3. Percent error between EIA AEO forecast for wellhead oil prices in Rocky Mountain region and actual wellhead prices in Utah. Positive values are over predictions, negative values under predictions. Columns indicate number of years into the future for the prediction (i.e. year 4 of AEO 1999 is prediction for 2002).

AEO	Year															
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
1999	-37	-102	-52	-39	-51	-88	-137	-143	-136	-214	-84	-143	-185	-177	-178	-163
2000	-37	-14	-12	-30	-71	-126	-142	-143	-222	-90	-150	-187	-184	-188	-174	
2001	2	-8	-31	-71	-128	-147	-150	-232	-94	-155	-196	-191	-191	-174		
2002	-10	-24	-61	-116	-135	-135	-213	-83	-141	-182	-177	-177	-162			
2003	-5	-55	-114	-133	-134	-210	-81	-137	-177	-175	-175	-159				
2004	-56	-122	-138	-138	-215	-84	-146	-151	-177	-177	-155					
2005	-54	-100	-112	-197	-81	-143	-183	-174	-172	-154						
2006	-14	-21	-67	-2	-38	-60	-57	-59	-49							
2007	1	-45	9	-29	-61	-67	-71	-66								
2008	2	38	14	-7	-13	-22	-23									
2009	14	13	8	18	22	29										
2010	8	-8	3	10	19											
2011	10	14	15	23												
2012	21	27	36													
2013	12	17														
2014	12															
Mean	-8.26	-26.07	-35.91	-54.88	-73.78	-95.67	-120.18	-131.95	-146.14	-163.58	-156.03	-171.41	-180.57	-179.56	-175.82	-163.02
SD	24.68	49.60	55.82	70.45	69.88	66.21	59.95	55.21	54.25	38.24	39.09	20.29	13.01	7.46	2.94	---

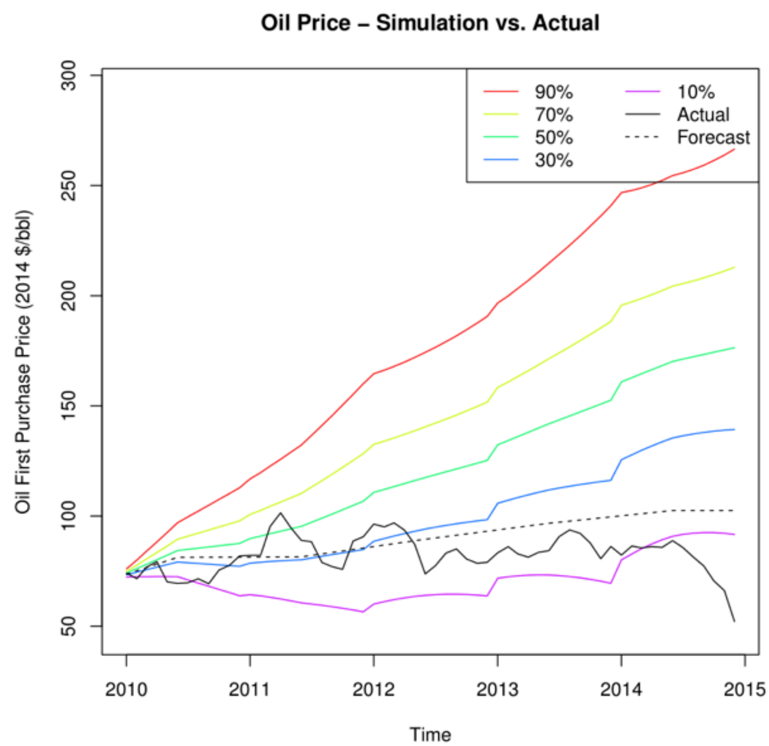

Figure 2. Simulated vs. actual oil price paths using EIA AEO error propagation method. Base forecast is AEO 2010. Results shown are after 1000 Monte-Carlo runs using errors shown in Table 3.

One problem with using Equation (1) is that about 17% of wells do not have curve fits, primarily because the DCA algorithm skips any wells with fewer than 12 non-zero production records (to avoid over fitting where there are too few data points). Analysis of the population of wells that were skipped revealed that about half of the wells skipped for having too few non-zero production records were wells that were recently drilled (i.e. drilled within five years of the start of the simulation time period). These wells were assumed to be productive wells, and a field level hyperbolic decline curve fit was used to estimate their production (taking into account age of each well). The results of using this approach are shown below in Figure 3.

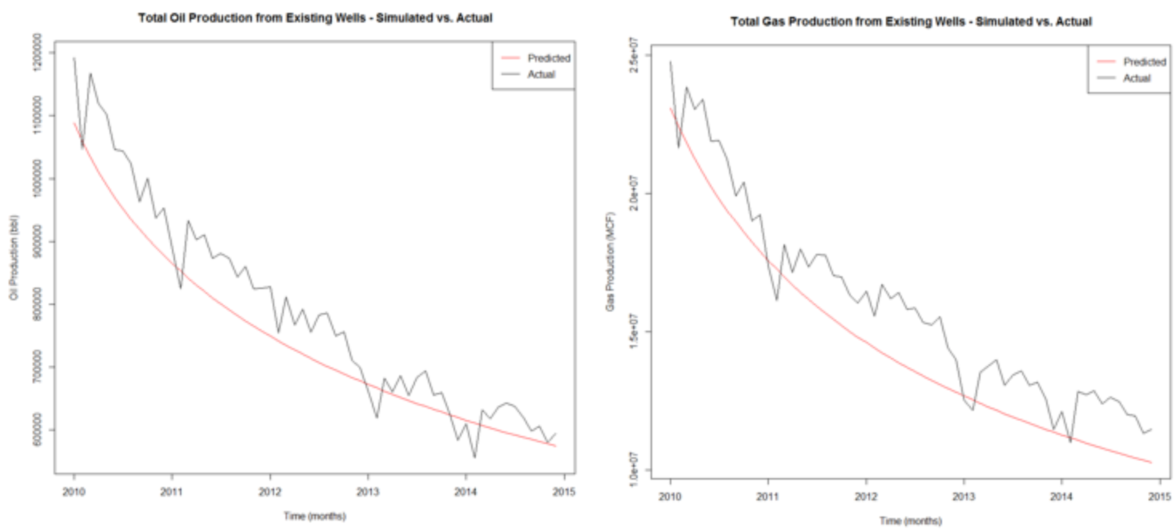

Figure 3. Predicted vs. actual oil and gas production from existing wells.

<u>Subtask 3.4 - V/UQ Analysis of Basin Scale CLEAR$_{uff}$ Assessment Tool (PI: Jennifer Spinti)</u>

A summary of progress in this subtask is included with the Subtask 3.3 summary above.

Task 4.0 - Liquid Fuel Production by In-situ Thermal Processing of Oil Shale/Sands

<u>Subtask 4.1 (Phase II) - Development of CFD-based Simulation Tools for In-situ Thermal Processing of Oil Shale/Sands (PI: Philip Smith)</u>

The majority of the project team's efforts during this quarter went to completing tasks associated with Subtask 7.3. They will be completing both deliverables by the end of the program.

- Distribute CFD-based simulation software over the web
- Topical Report on lessons learned from V/UQ study of thermal processing product yields as a function of operating conditions for indirectly heated, rubblized oil shale beds

Subtask 4.2 - Reservoir Simulation of Reactive Transport Processes (PI: Milind Deo)

The final deliverable for this project, a topical report, is being submitted with this report. This project is now completed.

Subtask 4.3 – Multiscale Thermal Processes (PI: Milind Deo, Eric Eddings)

This project has one remaining deliverable, a paper describing the Chemical Percolation Devolatilization (CPD) model application to oil shale pyrolysis. This paper is still in progress.

Subtask 4.4 - Effect of Oil Shale Processing on Water Compositions (PI: Milind Deo)

This project has been completed.

Subtask 4.5 - In Situ Pore Physics (PI: Jan Miller, Chen-Luh Lin)

This project has been completed.

Subtask 4.6 - Atomistic Modeling of Oil Shale Kerogens and Oil Sand Asphaltenes (PI: Julio Facelli)

This project has been completed.

Subtask 4.7 - Geomechanical Reservoir State (PI: John McLennan)

This project has one remaining milestone and one deliverable. Both are listed below with their current status.

- (Milestone) Complete thermophysical and geomechanical property data analysis and validation–Data collection is complete. Numerical methods to allow interpolation of all in-house and public domain data continues and will be completed in the next quarter. Team members decided to do additional modeling because they were unsatisfied with how the numerical predictions (using a distinct element code, PFC3D) matched the experimental data.
- (Deliverable) Topical Report assessing subsidence and compaction implications of in situ development of oil shale (joint with Subtask 7.1)–A draft report has been written and peer-reviewed internally. The author is making modifications and doing additional simulations at the suggestion of the reviewers.

As part of his MS thesis, Mr. Walter Glauser is completing the development of a computational methodology for simulation of the subsidence and compaction associated with in-situ pyrolysis of oil shale. Mr. Glauser's numerical simulations have indicated several crucial concerns (or at least highlighted concerns presented by previous researchers). These include:

1. Without removal of the liquids created, significant conversion of liquids to char occurs.

2. Without significant conductive pathways for removal of liquids, volumetric expansion is anticipated, leading to heave. If or when drainage occurs, some subsidence is expected.
3. Conversion of kerogen to gas and, to a lesser extent, oil generates pressure that can exceed the in-situ stresses. This can cause local hydraulic fracturing. Researchers are looking for methods to represent these new conductive pathways in the numerical modeling.

Mr. Thang Tran has been engaged in numerical simulations of the triaxial testing measurements that were previously performed.

Subtask 4.8 - Developing a Predictive Geologic Model of the Green River Oil Shale, Uinta Basin (PI: Lauren Birgenheier)

The project team is working on a topical report.

Subtask 4.9 - Experimental Characterization of Oil Shales and Kerogens (PI: Julio Facelli)

This project has been completed.

Task 5.0 - Environmental, Legal, Economic and Policy Framework

Subtask 5.1 – Models for Addressing Cross-Jurisdictional Resource Management (PI: Robert Keiter, John Ruple)

This project has been completed.

Subtask 5.2 - Conjunctive Management of Surface and Groundwater Resources (PI: Robert Keiter, John Ruple)

This project has been completed.

Subtask 5.3 - Policy and Economic Issues Associated with Using Simulation to Assess Environmental Impacts (PI: Robert Keiter, Kirsten Uchitel)

This project has been completed.

6.0 – Economic and Policy Assessment of Domestic Unconventional Fuels Industry

Subtask 6.1 Engineering Process Models for Economic Impact Analysis (PI: Terry Ring)

This project has been completed.

Subtask 6.2 - Policy analysis of the Canadian oil sands experience (PI: Kirsten Uchitel)

This project has been completed.

Subtask 6.3 – Market Assessment Report (PI: Jennifer Spinti)

This project has been completed.

7.0 – Strategic Alliance Reserve

Subtask 7.1 – Geomechanical Model (PI: John McLennan)

This project has two remaining milestones and a deliverable, listed below with their current status:

- (Milestone) Infer permeability-porosity-temperature relationships, develop model that can be used by other subtasks–The project team is continuing to measure post-pyrolysis permeability on a 25 gallon per ton (GPT) oil shale sample.
- (Milestone) Evaluation of flow mechanics–This milestone is discussed in the upcoming topical report.
- (Deliverable) Topical Report assessing subsidence and compaction implications of in situ development of oil shale (joint with Subtask 4.7)–The author of the draft report is making modifications and doing additional simulations at the suggestion of the reviewers.

During this quarter, Mr. Glauser completed his simulations and Mr. Tran completed permeability measurements on pyrolyzed specimens. Mr. Tran has also been engaged in numerical simulations of the triaxial testing measurements that were previously performed.

The majority of experimental assessment in this quarter was spent on two shale samples from the Green River Formation–a lean shale sample with a grade of 8 GPT and a rich shale sample with a grade of 25 GPT. Both samples were pyrolyzed in the triaxial testing apparatus that has been described previously. Permeability and porosity were measured before and after pyrolysis. These tests were performed to comprehend how the liquid product flows out of the pyrolyzed samples (for assessment of the feasibility of production, where the end goal is to find the most cost-effective method of extracting the liquid product).

The first sample tested was a lean shale sample provided by the Utah Geological Survey (White River pedigree). Porosity testing was done using an Ultra-Pore 3000 porosimeter. Permeability testing was done at the EGI. After baseline testing, each sample was pyrolyzed using the triaxial testing apparatus to prevent swelling and fracturing. The pyrolyzed sample was then submitted to the same characterization tests. Characteristics for the lean sample are shown in Table 4.

Table 4. Lean shale measurements.

Lean Shale	**Before**	**After**
Porosity	2.1%	22.18%
Permeability	<2 nD	1.21 μD

Notice the remarkable change in both porosity and permeability with pyrolysis. Figure 4 synthesizes data from the permeability testing on the lean sample. Experimental parameters include flowing water at 0.05 ml/minute, which resulted in a pressure difference of ~1700 psi. The permeability measured was 1.2 μD compared to the pre-pyrolysis value of less than 2 nD. This correlates anticipation of evolution of interconnected pore space during pyrolysis.

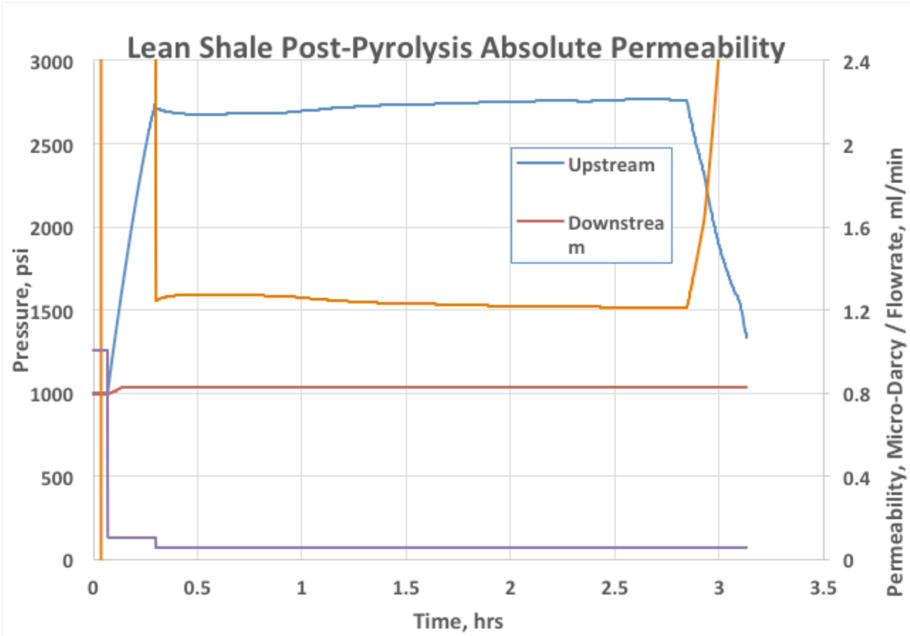

Figure 4. Post-pyrolysis absolute permeability measurements on a lean oil shale sample. The differential pressure was approximately 1700 psi.

The exact same procedures were used for the oil-rich sample. There were complications in running the porosity and permeability tests for this sample due to swelling of the plug during pyrolysis; the sample did not fit into the Ultra-Pore 3000 and Core-Flood systems. The research team is currently working on a method to pyrolyze the sample without the swelling (refer to Table 5). This swelling is an important observation that is consistent with numerical modeling by Mr. Glauser. Without the establishment and maintenance of drainage pathways (interconnected pores, hydraulic fractures, etc.) gas generation and porosity evolution will entail in situ swelling and possible surface heave. Even if volumetric expansion is precluded, the consequences can be counterproductive in terms of moving liquid and gas – any hydraulically induced channels can close due to plastic deformation.

Table 5. Permeability and porosity of 25 GPT sample.

Rich Shale	Before	After
Porosity	2.238%	?
Permeability	<2 nD	?

The permeability in these two samples is dependent on the orientation of the sample (vertical or horizontal). Vertical plugs aren't as permeable as horizontal plugs due to how the layers naturally form; the liquid product would rather follow the path of the laminae (which usually is nominally horizontal; small dip). Without well-developed laterally extensive laminae, removal of produced liquids and gases will be very difficult.

Presently, researchers are uncertain about the relationship between permeability and sample richness. It could be speculated (upcoming measurements will confirm) that the richer sample will have a higher permeability.. During pyrolysis, the sample undergoes swelling as the solid-phase kerogen turns into liquid and expands. This swelling is hypothesized to create cracks. As the liquid flows out of the sample, pathways develop that factor into how porous and permeable the sample will be after pyrolysis. Longer-term integrity of these pathways is uncertain. They could heal as a consequence of plastic deformation.

Subtask 7.2 – Kinetic Compositional Models and Thermal Reservoir Simulators (PI: Milind Deo)

Project has been terminated.

Subtask 7.3 – Rubblized Bed High Performance Computing Simulations (PI: Philip Smith)

In the January-March 2015 quarter, researchers have continued to run their High Performance Computing simulations of the in-situ thermal treatment of oil shale. They used a modified simulation domain to optimize the well distribution throughout the formation located in the Uinta Basin. The results were presented at STAR Global Conference in March 2015.

The milestone to perform a generation 2 simulation that incorporates kinetic compositional models was completed in this quarter. Using the user-coding capabilities of STAR-CCM+, the research team has implemented a first-order kinetic reaction model in this quarter. Its form is:

$$\frac{dm}{dt} = -km \tag{4}$$

where *k* is the reaction rate constant, *m* is the mass of kerogen available in the oil shale, and *t* represents time. The reaction rate constant is in the form of the Arrhenius equation:

$$k = Ae^{(-E/RT)} \tag{5}$$

where *k* is the rate constant, *A* is the pre-exponential factor, set as 9.5×10^{13} 1/s, *E* is the activation energy, set as 221 kJ/mol, *R* is the universal gas constant, and *T* is the temperature. Values for both the pre-exponential factor as well as activation energy were determined experimentally by Prof. Tom Fletcher from BYU based on samples of oil shale from the Uinta Basin.

In the previous quarter, the research team reported results from three test scenarios with different well arrangements located in the Uinta Basin. This quarter they have modified the geometry domain in order to explore a larger number of test scenarios and to determine the most optimal design for the formation where their test scenarios are located.

The new domain, shown in Figure 5, represents a smaller subspace of the simulation domain used previously. The new simulation domain is 5 m thick, 250 m deep, and 176 m wide. However, because of the decreased domain size, the research team was able to run a larger number of well spacings and arrangements to find an optimum design. The new domain required a new set of boundary conditions, as shown in Figure 6. By using periodic boundary conditions in the axial direction of the wells, results for various well lengths can be extrapolated. Same as previously, the heaters are assumed to heat at a temperature of 675 K. The other boundaries of the domain are held at 300 K to represent the heat losses to the shale formation surrounding the simulation domain. This boundary condition effectively provides a heat sink since the heat is not able to diffuse into a domain outside of what is captured in the simulation.

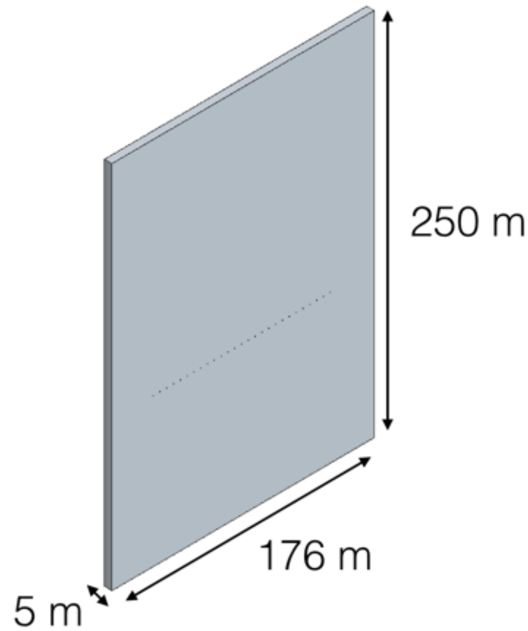

Figure 5. Reduced simulation domain showing one row of wells.

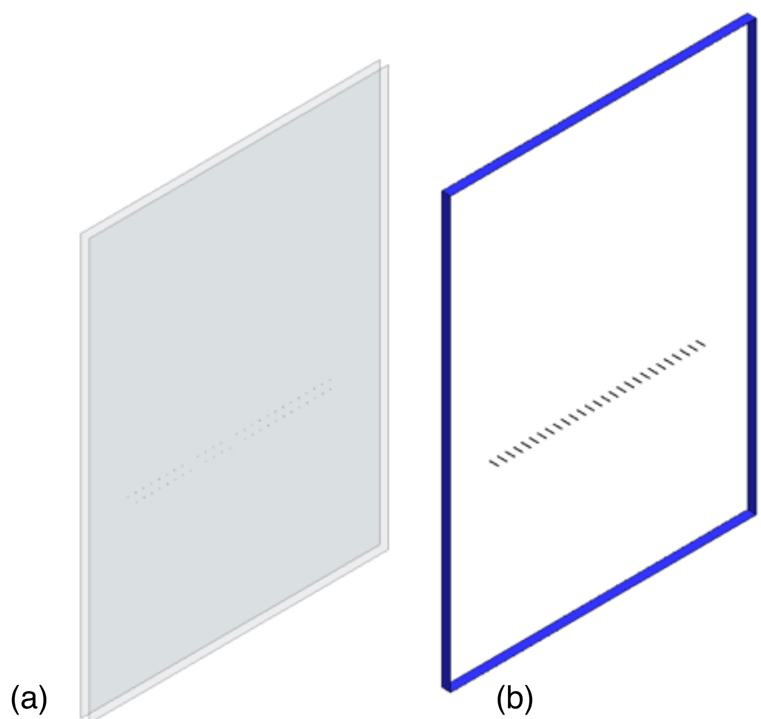

Figure 6. New set of boundary conditions for the smaller simulation domain: (a) Periodic boundaries, (b) outer boundary is held at constant formation temperature of 300 K, while the heaters are held at constant temperature of 675 K.

The following six parameters were varied in the test scenarios: well radius, lateral well spacing, vertical well spacing, number of well rows, vertical well offset, and vertical location. These parameters, along with the minimum and maximum values for each parameter used in the optimization design, are shown in Table 6.

Table 6. Design parameters and their minimum and maximum values used for our optimization study.

Design Parameter	Minimum Value	Maximum Value
Well radius	0.11 m	0.25 m
Lateral well spacing	4.6 m	12.2 m
Vertical well spacing	4.6 m	12.2 m
Number of well rows	1	10
Vertical well spacing	0 degrees	60 degrees
Vertical location	Spanning entire domain	-

For the optimization study, the research team used a multi-objective optimization with the following three objectives:

1) Maximize net energy return (NER)
2) Maximize oil production
3) Minimize well surface area (i.e. minimize the number of wells)

Five years of heating were simulated for 64 designs with various combinations of the design parameters listed in Table 6. Each simulation was run on 876 processors. All simulations were run using STAR-CCM+ together with the built-in Optimate+ optimization package, available commercially. Temperature distributions after five years of heating for three selected designs are shown in Figure 7.

As can be seen, the temperature contour plots show non-trivial temperature distributions which can only be predicted using high fidelity models with run with detailed oil shale richness distributions. Based on these temperature distributions, the amount of oil generated after five years of heating can be calculated. For all simulations, all of the product is assumed to be liquid oil (e.g. there are no gaseous products). For each simulation, the amount of heat supplied by all heaters over the entire heating period is also calculated. Based on the amount of oil produced and the heat supplied, the NER is calculated as:

$$NER = \frac{E_{out}}{E_{in}} \tag{6}$$

where E_{out} is the energy out calculated as the energy equivalent contained in the volume of oil produced (1 BOE contains 1.7 MWh of energy) and E_{in} is the energy supplied by the heaters. Any value of NER greater than one signifies that the energy content of the product is greater than the energy supplied by the heaters.

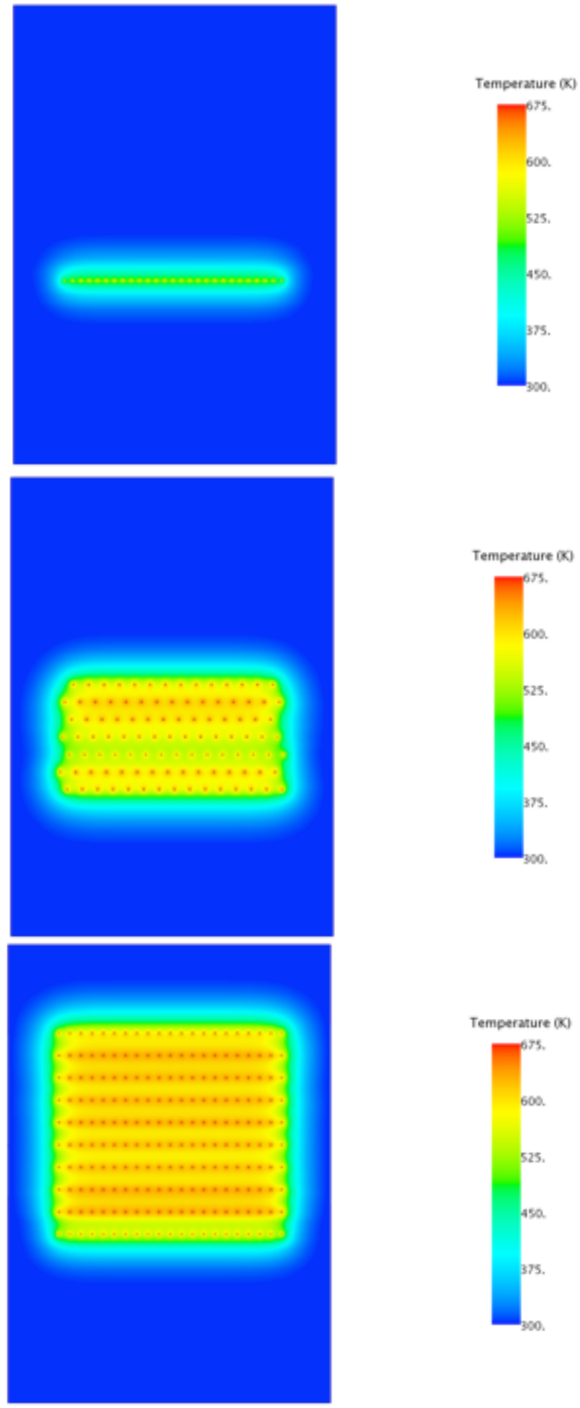

Figure 7. Temperature distributions after 5 years of heating for three selected designs.

NER values for all 64 designs as a function of the number of wells are shown in Figure 8. As can be seen, there is a large span of NER values ranging from 0.1 to 5. The size of the bubbles represents the amount of oil produced. In general, the largest amount of oil is produced from designs containing larger numbers of wells. However, designs with the largest NER values do not produce the greatest amount of oil nor do they have the largest amount of wells. This plot clearly shows that, for this location in the Uinta Basin, the amount of oil produced and the overall NER varies widely over the range of designs.

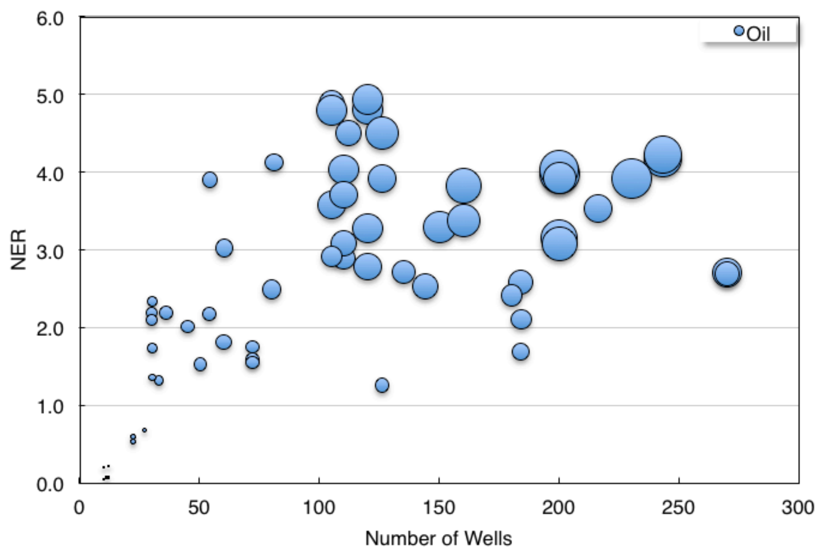

Figure 8. NER as a function of the number of wells for all 64 designs. Size of the bubble represents the amount of oil generated–the larger the bubble, the greater the amount of oil generated.

Figure 9 shows the same results in a slightly different format. In this figure, NER is given as a function of the oil produced divided by the number of wells with the size of the bubble representing the number of wells drilled. To minimize drilling costs, it is beneficial to maximize the ratio of oil produced versus the number of wells drilled. Therefore, the optimum design maximizes NER and the ratio of oil produced to number of wells but minimizes the size bubble size (number of wells drilled). Based on results presented in Figures 8 and 9, design 55, the furthermost point along the x-axis in Figure 9, is the optimum design for further analysis. Characteristics of design 55 are shown in Figure 10.

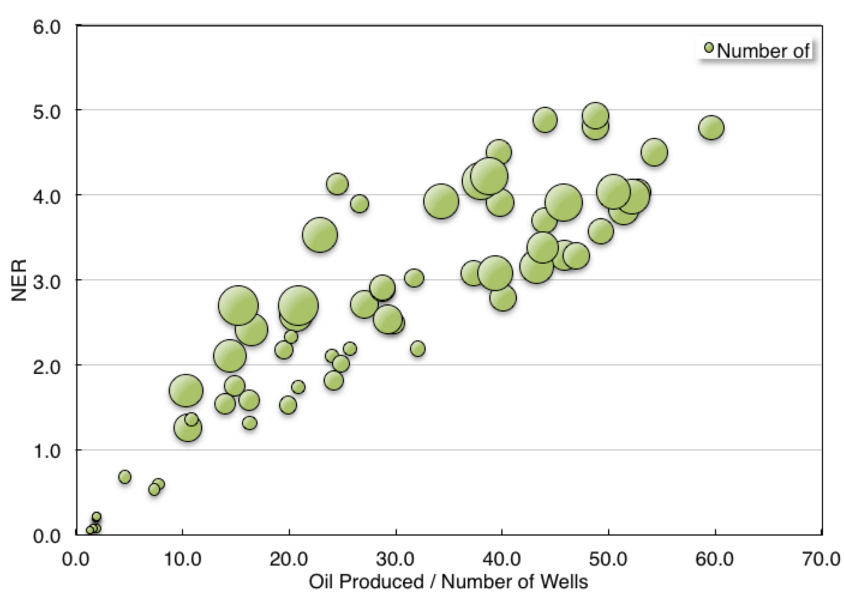

Figure 9. NER as a function of the ratio of oil produced to number of wells drilled. The size of the bubble represents the number of wells–the larger the bubble, the greater the number of wells drilled.

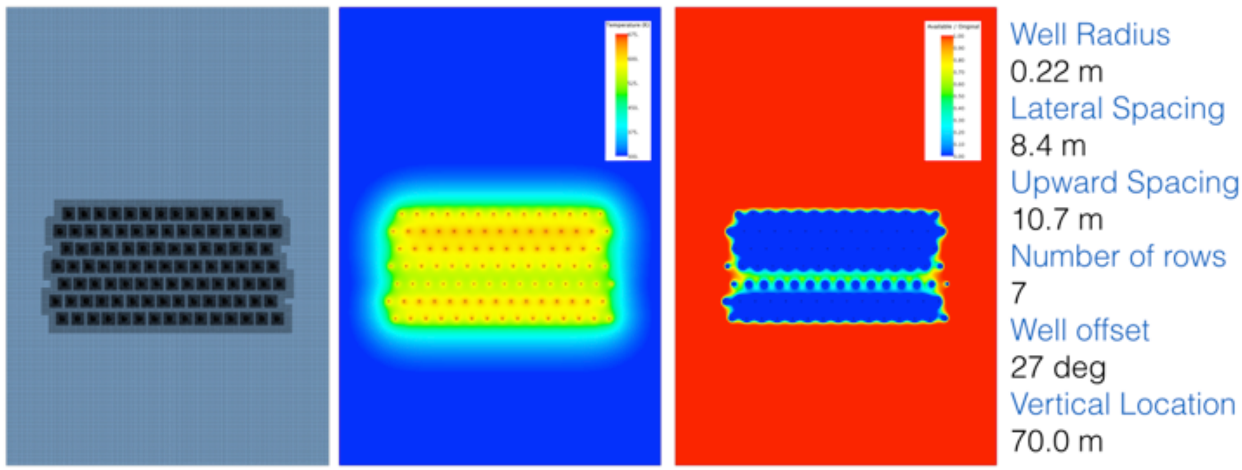

Figure 10. Characteristics of design 55, the optimum design in this study.

These results were presented at the STAR Global Conference in March 2015. The conference presentation is included in Appendix A.

CONCLUSIONS

The remaining projects have consolidated their efforts and are working on their final analyses and reports. Subtask 3.3 and 3.4 researchers continued refinements of their basin-scale model for estimated oil and gas production rates in the Uinta Basin. Subtask 4.1 and 7.3 researchers focused on optimizing the well arrangement for an in situ oil shale process. This arrangement maximizes NER and minimizes the number of wells drilled. Subtask 4.7 and 7.1 researchers have completed a draft of their topical report and two graduate students are wrapping up their work of developing a simulation tool for studying subsidence and compaction associated with in-situ pyrolysis of oil shale.

COST PLAN/STATUS

Baseline Reporting Quarter - PHASE I	Yr. 1								Yr. 2			
	Q1		Q2		Q3		Q4		Q5		Q6	
	7/1/09 - 12/31/09		1/1/10 - 3/31/10		4/1/10 - 6/30/10		7/1/10 - 9/30/10		10/1/10 - 12/31/10		1/1/11 - 3/31/11	
	Q1	Total	Q2	Total	Q3	Total	Q4	Total	Q5	Total	Q6	Total
Baseline Cost Plan												
Federal Share	484,728	**484,728**	484,728	**969,456**	484,728	**1,454,184**	484,726	**1,938,910**	323,403	**2,262,313**	798,328	**3,060,641**
Non-Federal Share	121,252	**121,252**	121,252	**242,504**	121,252	**363,756**	121,254	**485,010**	80,835	**565,845**	199,564	**765,409**
Total Planned	605,980	**605,980**	605,980	**1,211,960**	605,980	**1,817,940**	605,980	**2,423,920**	404,238	**2,828,158**	997,892	**3,826,050**
Actual Incurred Cost												
Federal Share	420,153	**420,153**	331,481	**751,634**	547,545	**1,299,179**	428,937	**1,728,116**	593,386	**2,321,502**	307,768	**2,629,270**
Non-Federal Share	29,456	**29,456**	131,875	**161,332**	151,972	**313,304**	100,629	**413,933**	191,601	**605,534**	45,101	**650,635**
Total Incurred Costs	449,609	**449,609**	463,356	**912,966**	699,517	**1,612,483**	529,566	**2,142,049**	784,987	**2,927,036**	352,869	**3,279,905**
Variance												
Federal Share	64,575	**64,575**	153,247	**217,822**	-62,817	**155,005**	55,789	**210,794**	-269,983	**-59,189**	490,560	**431,371**
Non-Federal Share	91,796	**91,796**	-10,623	**81,172**	-30,720	**50,452**	20,625	**71,077**	-110,766	**-39,689**	154,463	**114,774**
Total Variance	156,371	**156,371**	142,624	**298,994**	-93,537	**205,457**	76,414	**281,871**	-380,749	**-98,878**	645,023	**546,145**

Note: Q5 and Q6 reflect both CDP 2009 and CDP 2010 SF424a projections as the award periods overlap.

Baseline Reporting Quarter - PHASE II	Yr. 2				Yr. 3							
	Q7		Q8		Q9		Q10		Q11		Q12	
	04/01/11 - 06/30/11		07/01/11 - 09/30/11		10/01/11 - 12/31/11		01/1/12 - 03/31/12		04/01/12 - 06/30/12		07/01/12 - 09/30/12	
	Q7	Total	Q8	Total	Q9	Total	Q10	Total	Q11	Total	Q12	Total
Baseline Cost Plan												
Federal Share	712,385	**3,773,026**	627,423	**4,400,449**	147,451	**4,547,900**	147,451	**4,695,351**	147,451	**4,842,802**	245,447	**5,088,249**
Non-Federal Share	178,100	**943,509**	156,854	**1,100,363**	36,863	**1,137,226**	36,863	**1,174,089**	36,863	**1,210,952**	58,906	**1,269,858**
Total Planned	890,485	**4,716,535**	784,277	**5,500,812**	184,314	**5,685,126**	184,314	**5,869,440**	184,314	**6,053,754**	304,353	**6,358,107**
Actual Incurred Cost												
Federal Share	449,459	**3,078,729**	314,813	**3,393,542**	271,897	**3,665,439**	267,784	**3,933,223**	191,438	**4,124,661**	232,367	**4,357,028**
Non-Federal Share	48,902	**699,537**	48,835	**748,372**	105,695	**854,067**	40,652	**894,719**	33,092	**927,811**	44,294	**972,105**
Total Incurred Costs	498,361	**3,778,266**	363,648	**4,141,914**	377,592	**4,519,506**	308,436	**4,827,942**	224,530	**5,052,472**	276,661	**5,329,133**
Variance												
Federal Share	262,926	**694,297**	312,610	**1,006,907**	-124,446	**882,461**	-120,333	**762,128**	-43,987	**718,141**	13,080	**731,221**
Non-Federal Share	129,198	**243,972**	108,019	**351,991**	-68,832	**283,159**	-3,789	**279,370**	3,771	**283,141**	14,612	**297,753**
Total Variance	392,124	**938,269**	420,629	**1,358,898**	-193,278	**1,165,620**	-124,122	**1,041,498**	-40,216	**1,001,282**	27,692	**1,028,974**

Baseline Reporting Quarter - PHASE II	Yr. 4								Yr. 5			
	Q13		Q14		Q15		Q16 - REVISED		**Q17**		Q18	
	10/01/12 - 12/31/12		01/01/13 - 03/31/13		04/01/13 - 06/30/13		07/01/13 - 09/30/13		**10/01/13 - 12/31/13**		01/01/14 - 03/31/14	
	Q13	Total	Q14	Total	Q15	Total	Q16	Total	Q17	Total	Q18	Total
Baseline Cost Plan												
Federal Share	146,824	**5,235,073**	146,824	**5,381,897**	146,824	**5,528,721**	-471,238	**5,057,483**	157,250	**5,214,733**	157,250	**5,371,983**
Non-Federal Share	36,705	**1,306,563**	36,705	**1,343,268**	36,705	**1,379,973**	-211,982	**1,167,991**	53,484	**1,221,475**	53,484	**1,274,959**
Total Planned	183,529	**6,541,636**	183,529	**6,725,165**	183,529	**6,908,694**	-683,220	**6,225,474**	210,734	**6,436,208**	210,734	**6,646,942**
Actual Incurred Cost												
Federal Share	128,349	**4,485,377**	180,613	**4,665,990**	233,732	**4,899,722**	157,761	**5,057,483**	113,187	**5,170,670**	148,251	**5,318,921**
Non-Federal Share	79,871	**1,051,976**	62,354	**1,114,330**	51,708	**1,166,038**	1,953	**1,167,991**	66,131	**1,234,122**	48,378	**1,282,500**
Total Incurred Costs	208,220	**5,537,353**	242,967	**5,780,320**	285,440	**6,065,760**	159,714	**6,225,474**	179,318	**6,404,792**	196,629	**6,601,421**
Variance												
Federal Share	18,475	**749,696**	-33,789	**715,907**	-86,908	**628,999**	-628,999	**0**	44,063	**44,063**	8,999	**53,062**
Non-Federal Share	-43,166	**254,587**	-25,649	**228,938**	-15,003	**213,935**	-213,935	**0**	-12,647	**-12,647**	5,106	**-7,541**
Total Variance	-24,691	**1,004,283**	-59,438	**944,845**	-101,911	**842,934**	-842,934	**0**	31,416	**31,416**	14,105	**45,521**

Baseline Reporting Quarter - PHASE II	Yr. 5				Yr. 6							
	Q19		Q20 - REVISED BUDGET		**Q21**		Q22		Q23		Q24	
	04/01/14 - 06/30/14		07/01/14 - 09/30/14		**10/01/14 - 12/31/14**		01/01/14 - 03/31/15		04/01/15 - 06/30/15		07/01/15 - 09/30/15	
	Q19	Total	Q20	Total	**Q19**	Total	Q20	Total	Q19	Total	Q20	Total
Baseline Cost Plan												
Federal Share	157,250	**5,529,233**	80,000	**5,609,233**	35,000	**5,644,233**	10,000	**5,654,233**	4,000	**5,658,233**	4,282	**5,662,515**
Non-Federal Share	53,484	**1,328,443**	44,136	**1,372,579**	30,000	**1,402,579**	8,000	**1,410,579**	3,000	**1,413,579**	2,300	**1,415,879**
Total Planned	210,734	**6,857,676**	124,136	**6,981,812**	65,000	**7,046,812**	18,000	**7,064,812**	7,000	**7,071,812**	1,700	**7,078,394**
Actual Incurred Cost												
Federal Share	147,582	**5,466,503**	86,384	**5,552,887**	70,197	**5,623,084**	20,816	**5,643,900**		**5,643,900**		**5,643,900**
Non-Federal Share	46,472	**1,328,971**	38,582	**1,367,554**	29,038	**1,396,592**	8,170	**1,404,761**		**1,404,761**		**1,404,761**
Total Incurred Costs	194,053	**6,795,474**	124,966	**6,920,441**	99,235	**7,019,676**	28,986	**7,048,661**	0	**7,048,661**	0	**7,048,661**
Variance												
Federal Share	9,668	**62,730**	-6,384	**56,346**	-35,197	**21,149**	-10,816	**10,333**	4,000	**14,333**	4,282	**18,615**
Non-Federal Share	7,012	**-528**	5,554	**5,025**	962	**5,987**	-170	**5,818**	3,000	**8,818**	2,300	**11,118**
Total Variance	16,681	**62,202**	-830	**61,371**	-34,235	**27,136**	-10,986	**16,151**	7,000	**23,151**	1,700	**29,733**

MILESTONE STATUS

ID	Title/Description	Planned Completion Date	Actual Completion Date	Milestone Status
1.0	Project management			
2.0	Technology transfer and outreach			
	Advisory board meeting	Jun-13	N/A	Decision has been made to disband EAB
	Hold final project review meeting	Jun-13		Meeting schedule for Sept. 16-17, 2015
3	Clean oil shale & oil sands utilization with CO2 management			
3.1	Lifecycle greenhouse gas analysis of conventional oil & gas development in the Uinta Basin			
	Complete modules in $CLEAR_{uff}$ for life-cycle CO2 emissions from conventional oil & gas development in the Uinta Basin	Nov-14	Dec-14	Discussed in this quarterly report
3.2	Flameless oxy-gas process heaters for efficient CO2 capture			
	Preliminary report detailing results of skeletal validation/uncertainty quantification analysis of oxy-gas combustion system	Sep-12	Oct-12	Report attached as appendix to Oct. 2012 quarterly report
3.3	Development of oil & gas production modules for $CLEAR_{uff}$			
	Develop preliminary modules in $CLEAR_{uff}$ for conventional oil & gas development & produced water management in Uinta Basin	Oct-11	Dec-11	Discussed in Jan. 2012 quarterly report
3.4	V/UQ analysis of basin scale $CLEAR_{uff}$ assessment tool			
	Develop a first generation methodology for doing V/UQ analysis	Oct-11	Nov-11	Discussed in Jan. 2012 quarterly report
	Demonstrate full functionality of V/UQ methodology for conventional oil development in Uinta Basin	Nov-13	Apr-14	Discussed in Apr. 2014 quarterly report
	Demonstrate full functionality for conventional & unconventional oil development in Uinta Basin	Mar-14	Jun-14	Discussed in July 2014 quarterly report

ID	Title/Description	Planned Completion Date	Actual Completion Date	Milestone Status
4	Liquid fuel processing by in-situ thermal production of oil shale/sands			
4.1	Development of CFD-based simulation tool for in-situ thermal processing of oil shale/sands			
	Expand modeling to include reaction chemistry & study product yield as a function of operating conditions	Feb-12	Mar-12	Discussed in April 2012 quarterly report
4.2	Reservoir simulation of reactive transport processes			
	Incorporate kinetic & composition models into both commercial & new reactive transport models	Dec-11	Dec-11	Discussed in Jan. & July 2012 quarterly reports
	Complete examination of pore-level change models & their impact on production processes in both commercial & new reactive transport models	Jun-12	Jun-12	Discussed in July 2012 quarterly report
4.3	Multiscale thermal processes			
	Complete thermogravimetric analyses experiments of oil shale utilizing fresh “standard” core	Sep-11	Sep-11	Discussed in Oct. 2011 quarterly report
	Complete core sample pyrolysis at various pressures & analyze product bulk properties & composition	Dec-11	Sep-12	Discussed in Oct. 2012 quarterly report
	Collection & chemical analysis of condensable pyrolysis products from demineralized kerogen	May-12	Sep-12	Discussed in Oct. 2012 quarterly report
	Complete model to account for heat & mass transfer effects in predicting product yields & compositions	Jun-12	Jun-12	Discussed in July 2012 quarterly report
	Perform experiments to resolve differences between Fletcher & Deo groups TGA data	Jul-14	Sep-14	Discussed Oct. 2014 quarterly report
	Extend CPD model for oil shale to include additional chemical structure features specific to oil shale	Jul-14	Sep-14	Discussed in Oct. 2014 quarterly report
4.5	In situ pore physics			
	Complete pore network structures & permeability calculations of Skyline 16 core for various loading conditions, pyrolysis temperatures, & heating rates	Mar-12	Mar-12	Discussed in April 2012 quarterly report; PI dropped loading condition var

ID	Title/Description	Planned Completion Date	Actual Completion Date	Milestone Status
4.6	Atomistic modeling of oil shale kerogens & oil sand asphaltenes			
	Complete web-based repository of 3D models of Uinta Basin kerogens, asphaltenes, & complete systems (organic & inorganic materials)	Dec-11	Dec-11	Discussed in Jan. 2012 quarterly report
4.7	Geomechanical reservoir state			
	Complete high-pressure, high-temperature vessel & ancillary flow system design & fabrication	Sep-11	Sep-11	Discussed in Oct. 2011 quarterly report
	Complete experimental matrix	Mar-14	May-14	Report sent to R. Vagnetti on 27 May 2014
	Complete thermophysical & geomechanical property data analysis & validation	Dec-14		Delayed until 2nd quarter of 2015
4.8	Developing a predictive geologic model of the Green River oil shale, Uinta Basin			
	Detailed sedimentologic & stratigraphic analysis of three cores &, if time permits, a fourth core	Dec-12	Dec-12	Discussed Jan. 2013 quarterly report
	Detailed mineralogic & geochemical analysis of same cores	Dec-12	Dec-12	Discussed Jan. 2013 quarterly report
4.9	Experimental characterization of oil shales & kerogens			
	Characterization of bitumen and kerogen samples from standard core	Jan-12	Feb-12	Email sent to R. Vagnetti on Feb. 6, 2012 & discussed in Apr. 2012 quarterly report
	Development of a structural model of kerogen & bitumen	Jun-12	Jun-12	Discussed in July 2012 quarterly report

ID	Title/Description	Planned Completion Date	Actual Completion Date	Milestone Status
5	Environmental, legal, economic, & policy framework			
5.1	Models for addressing cross-jurisdictional resource management			
	Identify case studies for assessment of multi-jurisdictional resource management models & evaluation of utility of models in context of oil shale & sands development	Jun-11	Jul-11	Discussed in Oct. 2011 quarterly report
5.2	Conjunctive management of surface & groundwater resources			
	Complete research on conjunctive surface water & groundwater management in Utah, gaps in its regulation, & lessons that can be learned from existing conjunctive water management programs in other states	Aug-11	Aug-11	Discussed in Oct. 2011 quarterly report
5.3	Policy & economic issues associated with using simulation to assess environmental impacts			
	White paper describing existing judicial & agency approaches for estimating error in simulation methodologies used in context of environmental risk assessment and impacts analysis	Dec-12	Dec-12	Submitted with Jan. 2103 quarterly report
6	Economic & policy assessment of domestic unconventional fuels industry			
6.1	Engineering process models for economic impact analysis			
	Upload all models used & data collected to repository	Oct-12	Aug-13	All models/data have been uploaded to the ICSE website
7	Strategic Alliance Reserve			
	Conduct initial screening of proposed Strategic Alliance applications	Mar-11	Mar-11	
	Complete review and selection of Strategic Alliance applications	Jun-11	Jul-11	Discussed in Oct. 2011 quarterly report
	Implement new Strategic Alliance research tasks	Sep-11	Sep-11	Discussed in Oct. 2011 quarterly report

ID	Title/Description	Planned Completion Date	Actual Completion Date	Milestone Status
7.1	Geomechanical model			
	Make experimental recommendations	Aug-13	Aug-13	Discussed in Oct. 2013 quarterly report
	Infer permeability-porosity-temperature relationships, develop model that can be used by other subtasks	Dec-14		Due date has been revised to reflect status of expts.
	Basic reservoir simulations to account for thermal front propagation	Mar-15	Dec-14	Discussed in Jan. 2015 quarterly report
	Evaluation of flow mechanics	Mar-15		Due date has been revised to reflect status of expts.
7.2	Kinetic compositional models & thermal reservoir simulators			Project has been terminated
	Incorporate chemical kinetics into thermal reservoir simulators	Jun-12	Jun-12	Discussed in July 2012 quarterly report
7.3	Rubblized bed HPC simulations			
	Collect background knowledge from AMSO about characteristics & operation of heated wells	Jun-12	Jun-12	Discussed in July 2102 quarterly report
	Perform generation 1 simulation - DEM, CFD & thermal analysis of characteristic section of AMSO rubblized bed	Sep-12	Sep-12	Discussed in Oct. 2012 quarterly report
	Perform generation 2 simulation that incorporates kinetic compositional models from subtask 7.2 and/or AMSO	Sep-14	Jan-15	Discussed in this quarterly report (mistakenly identified as completed in the previous quarterly report).

NOTEWORTHY ACCOMPLISHMENTS

Researchers from Subtasks 4.7 and 7.1 are performing permeability measurements on pyrolyzer samples to compare with similar measurements taken prior to pyrolysis. The novel approach taken by Researchers in Subtask 7.3 yielded an optimum design for in situ thermal treatment of oil shale

PROBLEMS OR DELAYS

Nothing to report.

RECENT AND UPCOMING PRESENTATIONS/PUBLICATIONS

Solum, M. S., Mayne, C. L., Orendt, A. M., Pugmire, R. J., Hall, T., Fletcher, T. H. (2014). Characterization of macromolecular structure elements from a Green River oil shale-(I. Extracts). Submitted to *Energy and Fuels, 28*, 453-465. dx.doi.org/10.1021/ef401918u,

Kelly, K.E., Wilkey, J. E. Spinti, J. P., Ring, T. A. & Pershing, D. W. (2014, March). Oxyfiring with CO_2 capture to meet low-carbon fuel standards for unconventional fuels from Utah. *International Journal of Greenhouse Gas Control, 22,* 189–199.

Fletcher, T. H., Gillis, R., Adams, J., Hall, T., Mayne, C. L., Solum, M.S., and Pugmire, R. J. (2014, January). Characterization of macromolecular structure elements from a Green River oil shale, II. Characterization of pyrolysis products from a Utah Green River oil shale by ^{13}C NMR, GC/MS, and FTIR. *Energy and Fuels, 28,* 2959-2970. dx.doi.org/10.1021/ef500095j

Hradisky, M., Smith, P. J., Burnham, A. K. (2014, March). STAR-CCM+ high performance computing simulations of oil shale retorting system using co-simulation. Presented at the STAR Global Conference, Vienna, Austria, March 2014.

Barfuss, D. C., Fletcher, T. H. Fletcher and Pugmire, R. J. (2014, October). Modeling oil shale pyrolysis using the Chemical Percolation Devolatilization model. Presented at the 34^{th} Oil Shale Symposium, Golden, CO, October 13-15, 2014.

Hardisky, M. and Smith, P. J. (2014, October). Evaluation of well spacing and arrangement for in-situ thermal treatment of oil shale using HPC simulation tools. Presented at the 34^{th} Oil Shale Symposium, Golden, CO, October 13-15, 2014.

Tran, T. and McLennan, J. (2014, November). Evaluation of transport properties of in-situ processed oil shale. Presented at *USTAR Confluence: Where Research Meets Commercialization*, Salt Lake City, UT, November 3-4, 2014.

Wilkey, J., Ring, T., Spinti, J., Pasqualini, D., Kelly, K., Hogue, M., & Jaramillo, I. (2015, January). Predicting emissions from oil and gas operations in the Uinta Basin. Presented at the *Air Quality in Utah: Science for Solutions Workshop,* Salt Lake City, UT, January 13, 2015.

Fletcher, T. H., Hillier, J., Gillis, R., Adams, J., Barfuss, D., Mayne, C. L., Solum, M. S. and Pugmire, R. J. (2015, January). Oil shale: Structure and reactions. Invited seminar, BYU Chemistry Department, Provo, UT, January 13, 2015.

Fletcher, T. H., Hillier, J., Gillis, R., Adams, J., Barfuss, D., Mayne, C. L., Solum, M.S. and Pugmire, R. J. (2015, January). Oil shale: Structure and reactions. Invited seminar, College of Engineering, University of Alabama Huntsville, Huntsville, AL, January 29, 2015.

Hradisky, M., Smith, P. J., Burnham, A. K. (2015, March). STAR-CCM+ HPC simulations of different well spacing and arrangements for in-situ themal treatment of oil shale. STAR Global Conference, San Diego, CA, March 16-18, 2015.

Birgenheier, L. & Vanden Berg, M. (n.d.). Facies, stratigraphic architecture, and lake evolution of the oil shale bearing Green River Formation, eastern Uinta Basin, Utah. To be published in Smith, M. and Gierlowski-Kordesch, E. (Eds.). *Stratigraphy and limnogeology of the Eocene Green River Formation*, Springer.

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National Energy Technology Laboratory (NETL). (2014). Life cycle analysis of natural gas extraction and power generation. DOE/NETL-2014-1646. Available at http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Life%20Cycle%20Analysis/NETL-NG-Power-LCA-29May2014.pdf.

Walton, I.C. (2012). Shale gas production analysis, Phase 1 final report. EGI internal report 100983. Summary available online at: http://egi.utah.edu/research/current-projects/i00983_2/#.

APPENDIX A. STAR-CCM+® HPC Simulations of Different Well Spacing & Arrangements for In-Situ Thermal Treatment of Oil Shale. Presentation delivered by Michal Hradisky at the 2015 STAR Global Conference.

STAR-CCM+® HPC Simulations of Different Well Spacing & Arrangements for In-Situ Thermal Treatment of Oil Shale

Michal Hradisky & Philip J. Smith
Institute for Clean and Secure Energy, University of Utah

STAR Global Conference
San Diego, CA
March 16 - 18, 2015

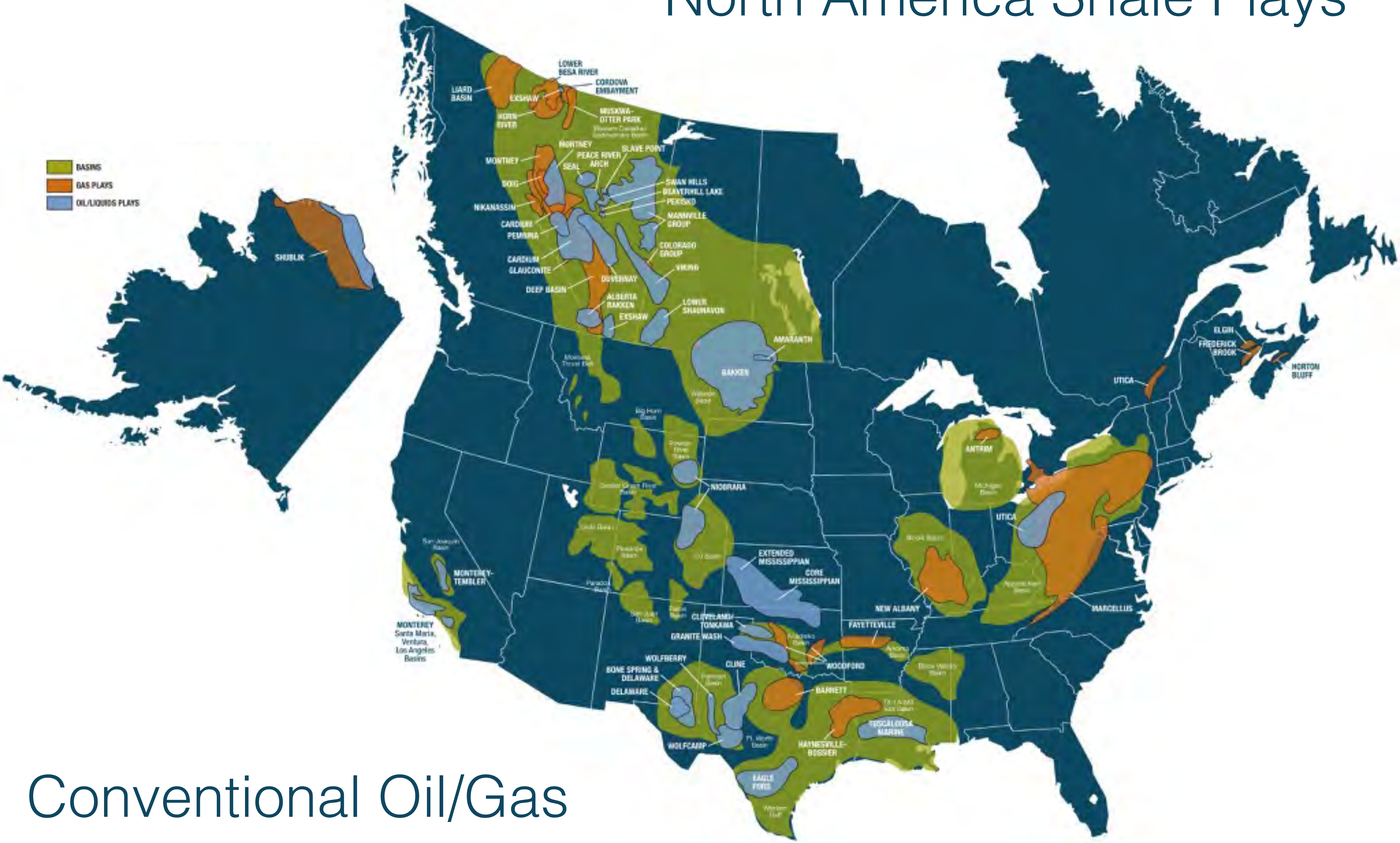
Organic-rich sedimentary rock
Kerogen is solid material bound within the mineral matrix
Heat is required to release hydrocarbons


Ian West (http://www.southampton.ac.uk/~imw/kimfire.htm)

Oil shale outcrop: Uinta Basin, Utah

Not to be confused with …

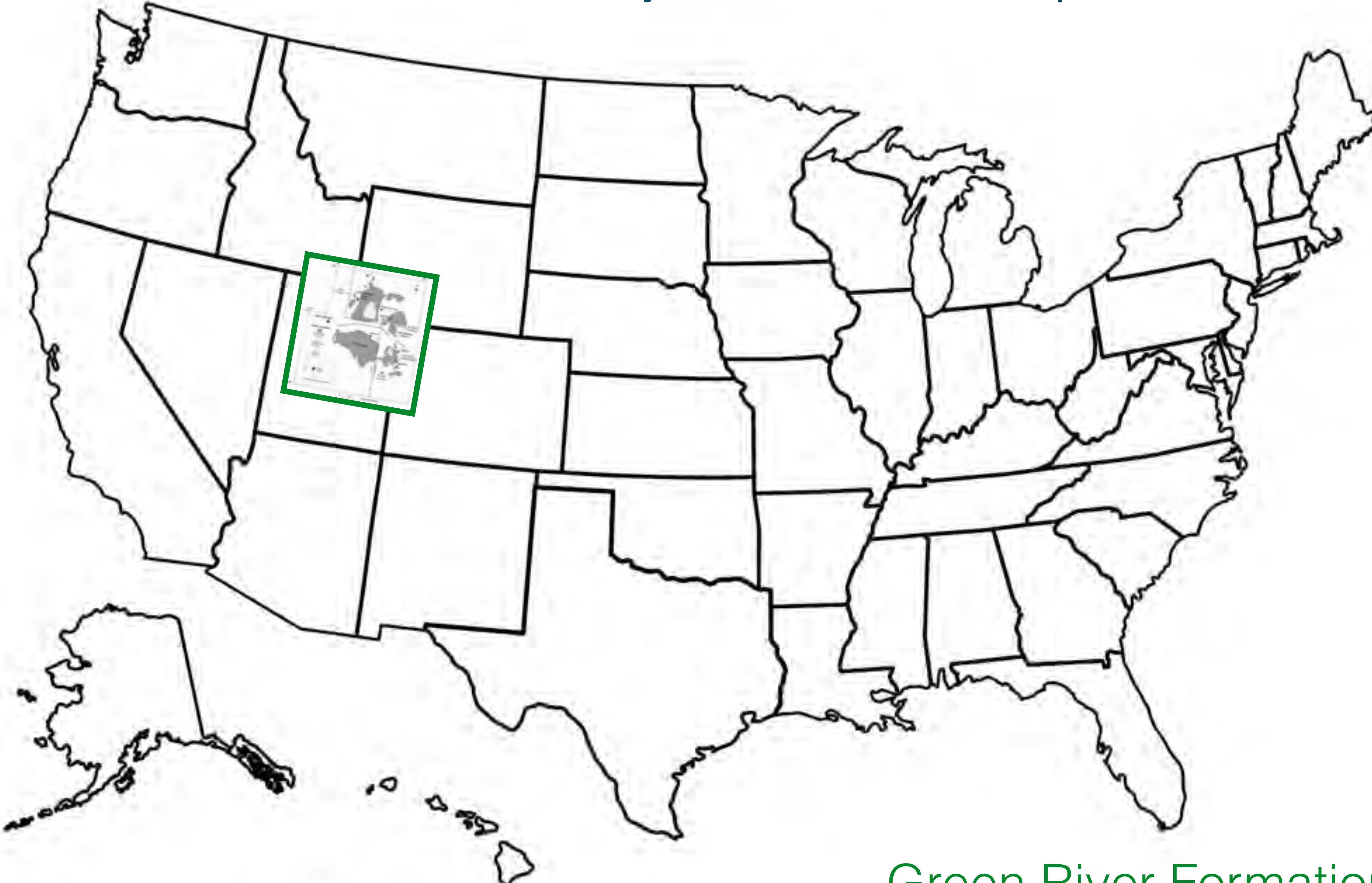
North America Shale Plays



Conventional Oil/Gas
trapped in shale
Tight Oil/Gas

PacWest Consulting Partners
http://pacwestcp.com/wp-content/uploads/2013/02/PacWest_NAM-Key-Plays_Feb-2013.jpg

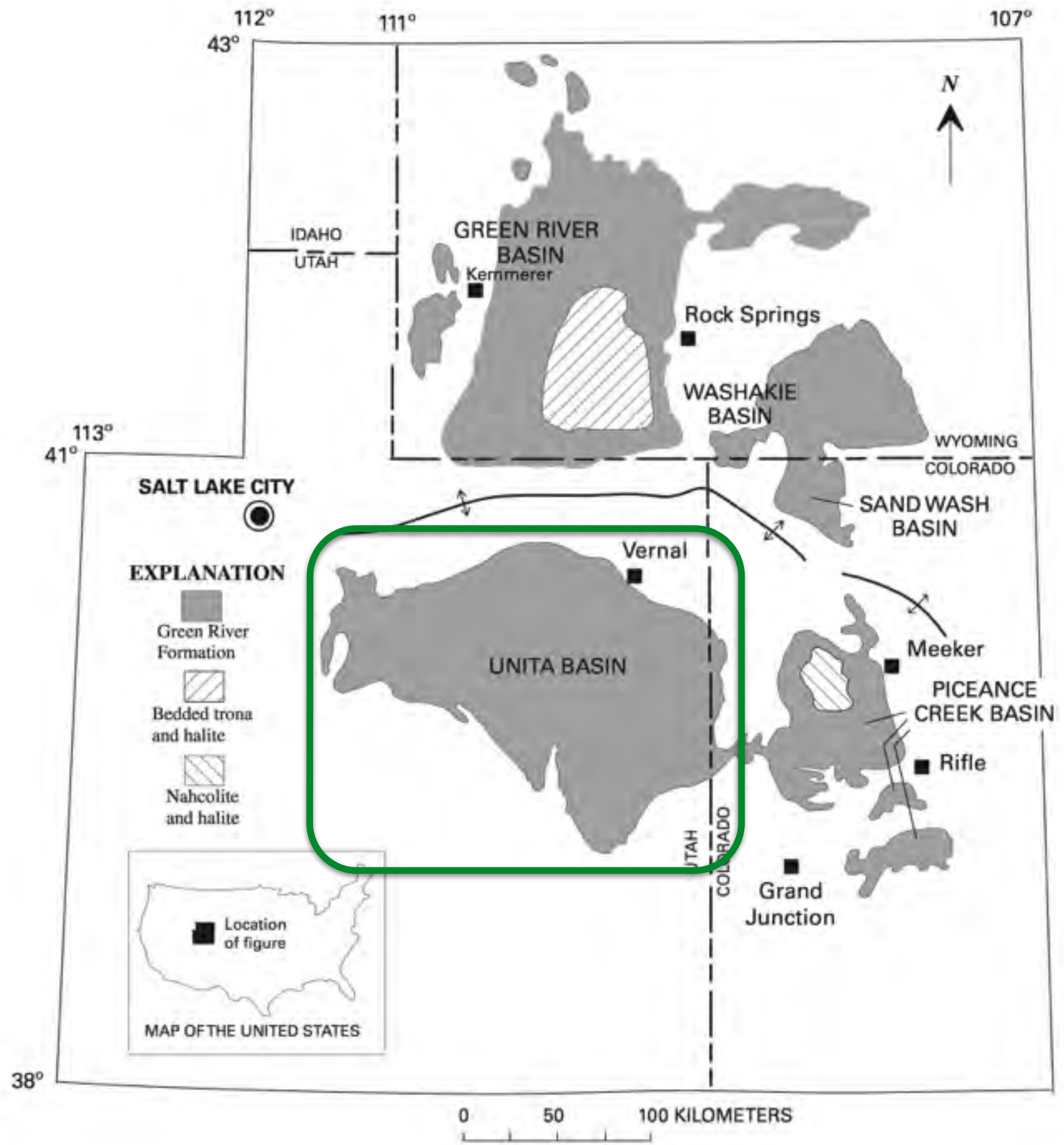
Major Oil Shale Deposits in US



Green River Formation

Colorado, Utah, Wyoming

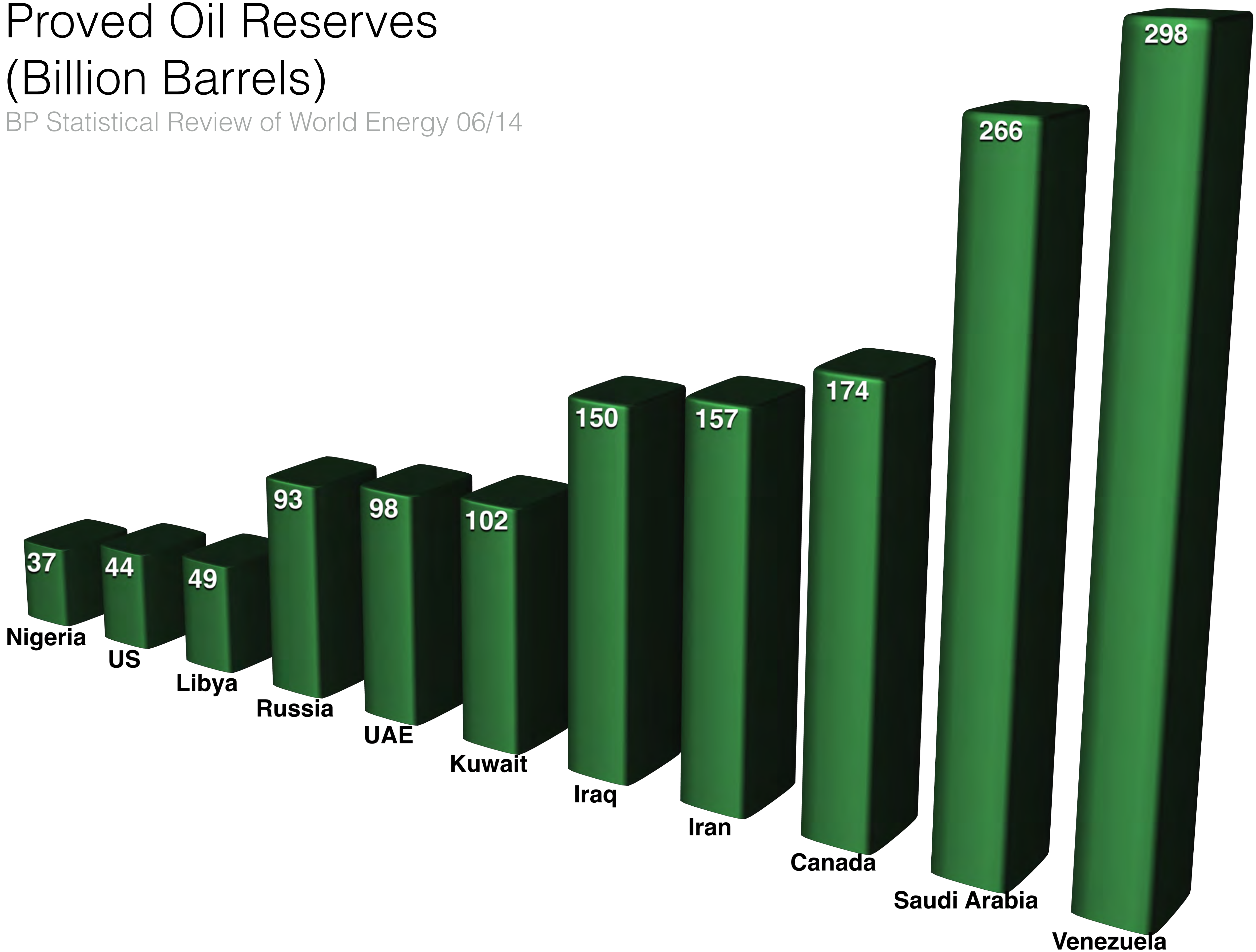
http://usamap.facts.co/USABlankMapwithStates.png



http://pubs.usgs.gov/sir/2005/5294/pdf/sir5294_508.pdf

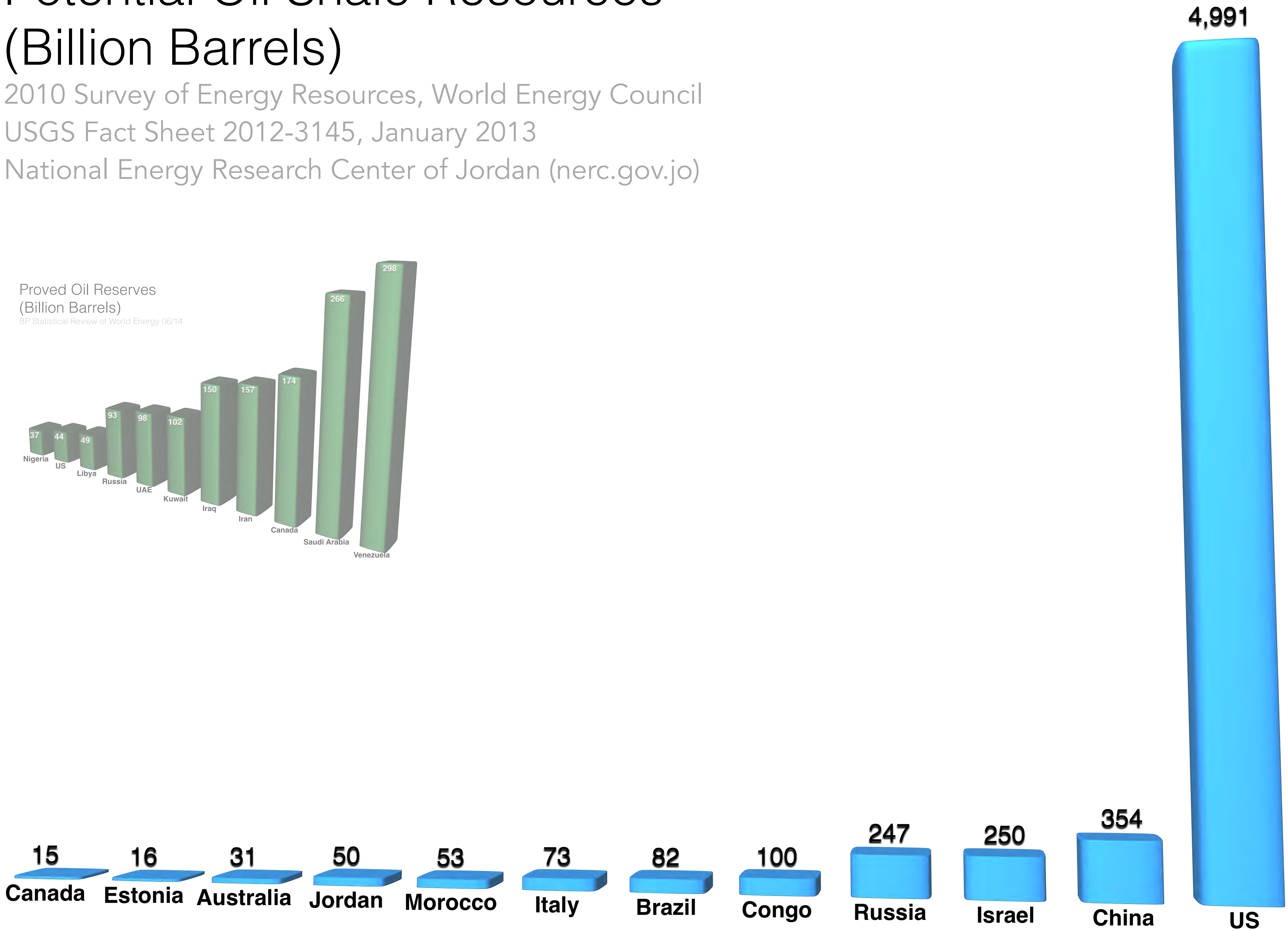
Proved Oil Reserves
(Billion Barrels)

BP Statistical Review of World Energy 06/14



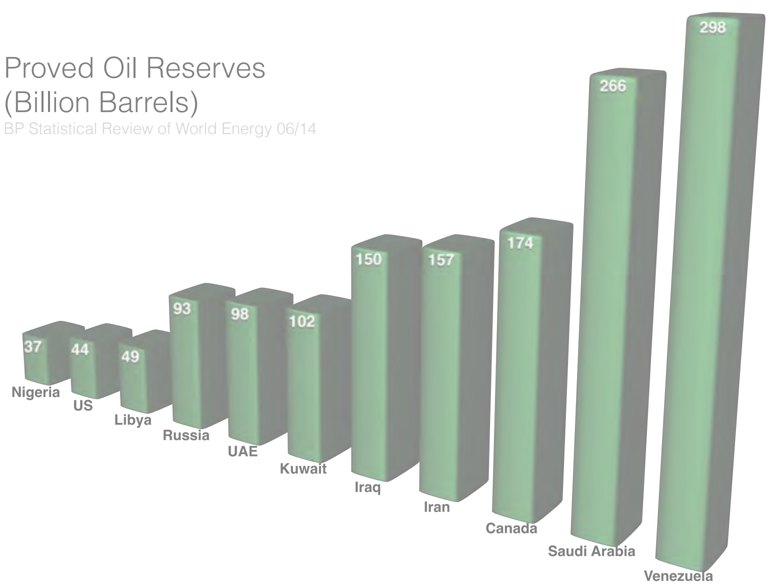
Potential Oil Shale Resources (Billion Barrels)

2010 Survey of Energy Resources, World Energy Council
USGS Fact Sheet 2012-3145, January 2013
National Energy Research Center of Jordan (nerc.gov.jo)



USGS Fact Sheet 2012-3145, January 2013

Proved Oil Reserves
(Billion Barrels)
BP Statistical Review of World Energy 06/14



Potential Oil Shale Resources
(Billion Barrels)
2010 Survey of Energy Resources, World Energy Council
USGS Fact Sheet 2012-3145, January 2013
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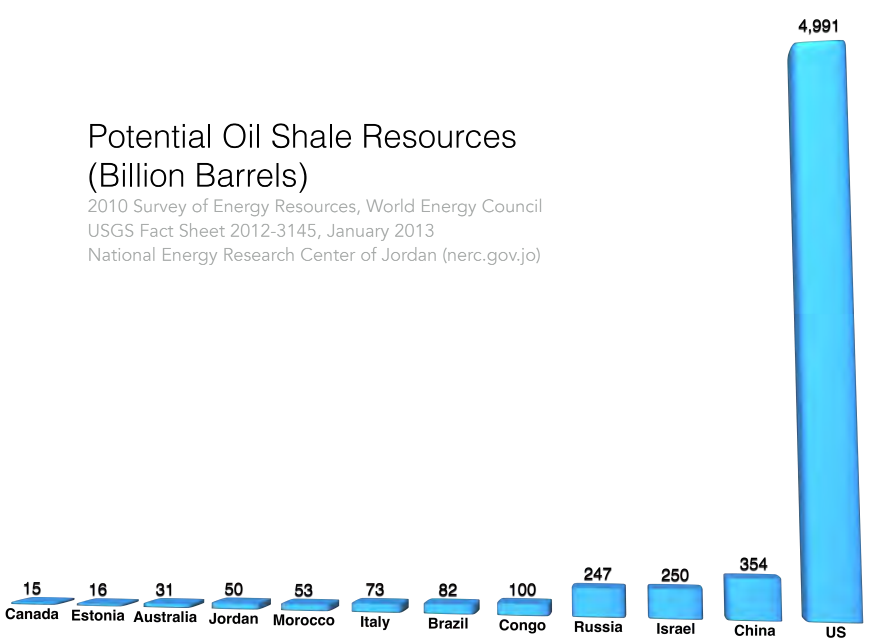
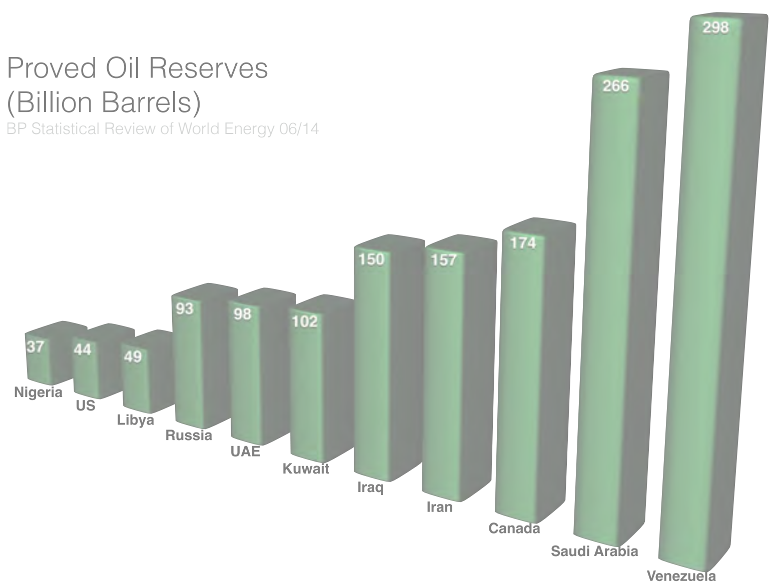
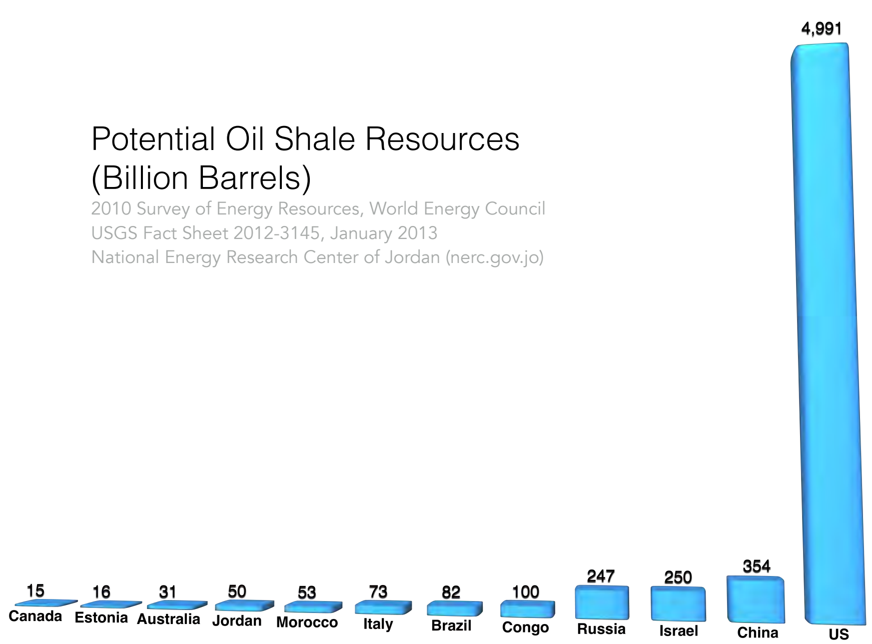


US Oil Shale
Resources

USGS Fact Sheet 2012-3145, January 2013

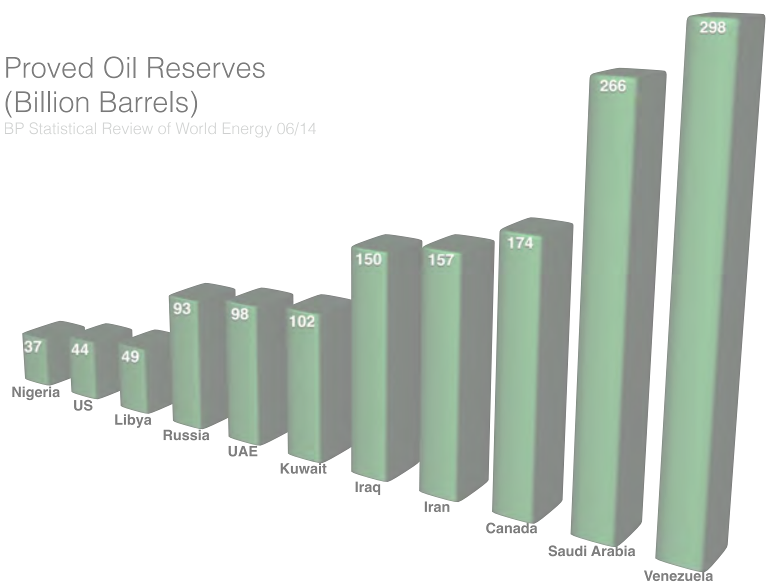




Green River
Formation

USGS Fact Sheet 2012-3145, January 2013

Proved Oil Reserves
(Billion Barrels)
BP Statistical Review of World Energy 06/14



Potential Oil Shale Resources
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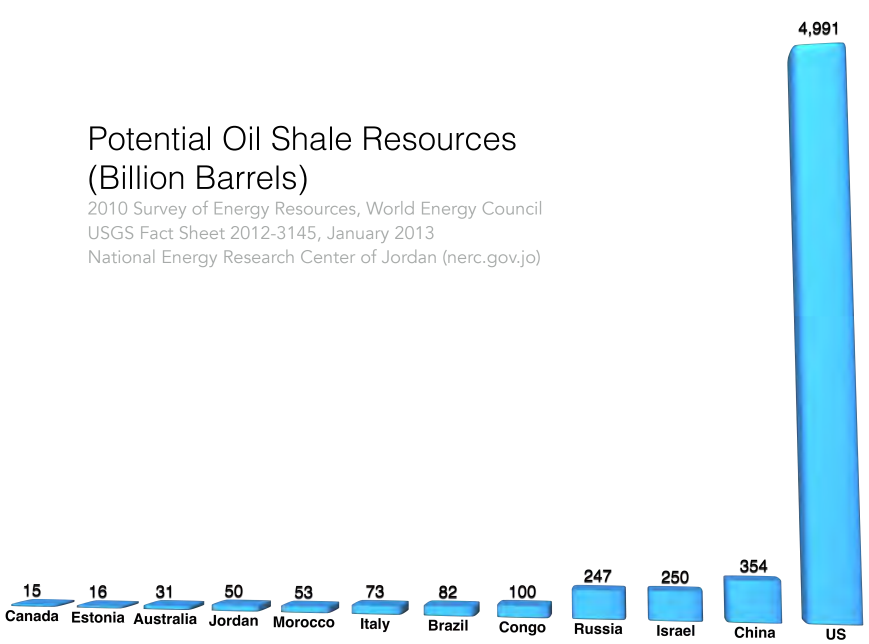
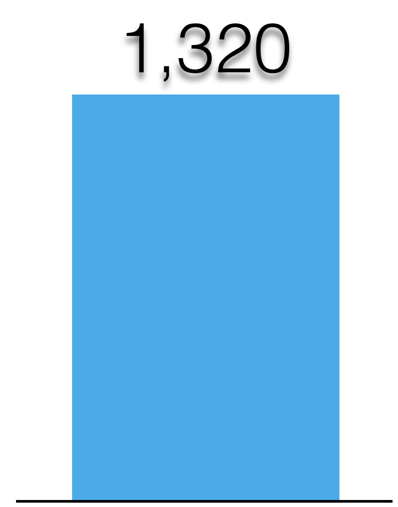
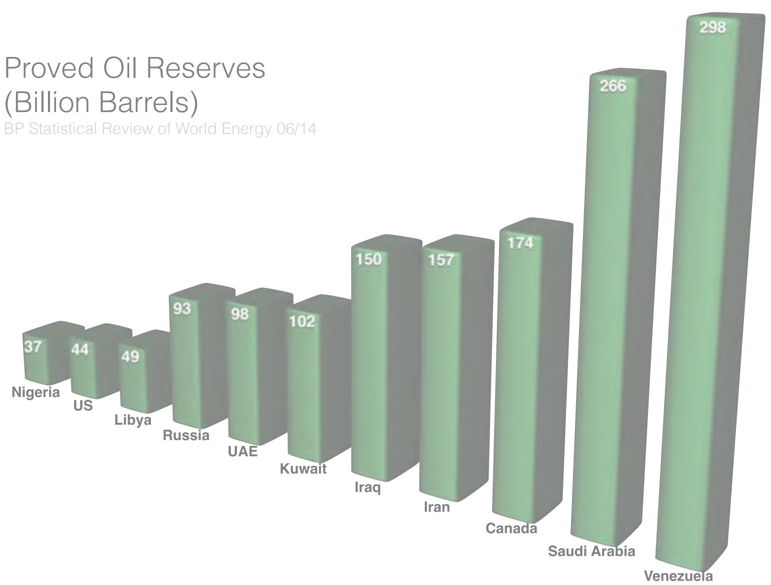


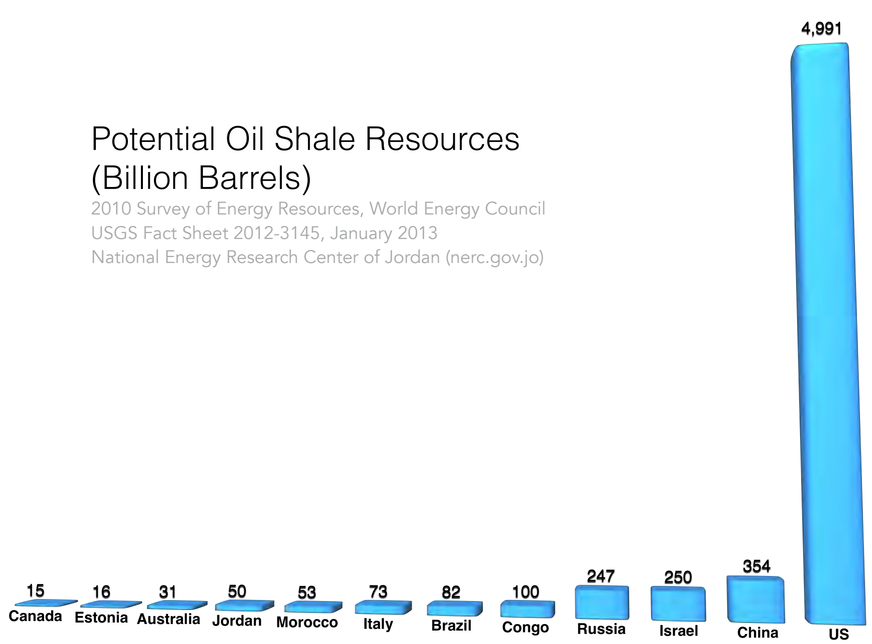


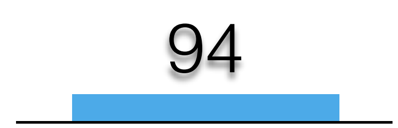
Uinta Basin

Proved Oil Reserves
(Billion Barrels)
BP Statistical Review of World Energy 06/14



Potential Oil Shale Resources
(Billion Barrels)
2010 Survey of Energy Resources, World Energy Council
USGS Fact Sheet 2012-3145, January 2013
National Energy Research Center of Jordan (nerc.gov.jo)

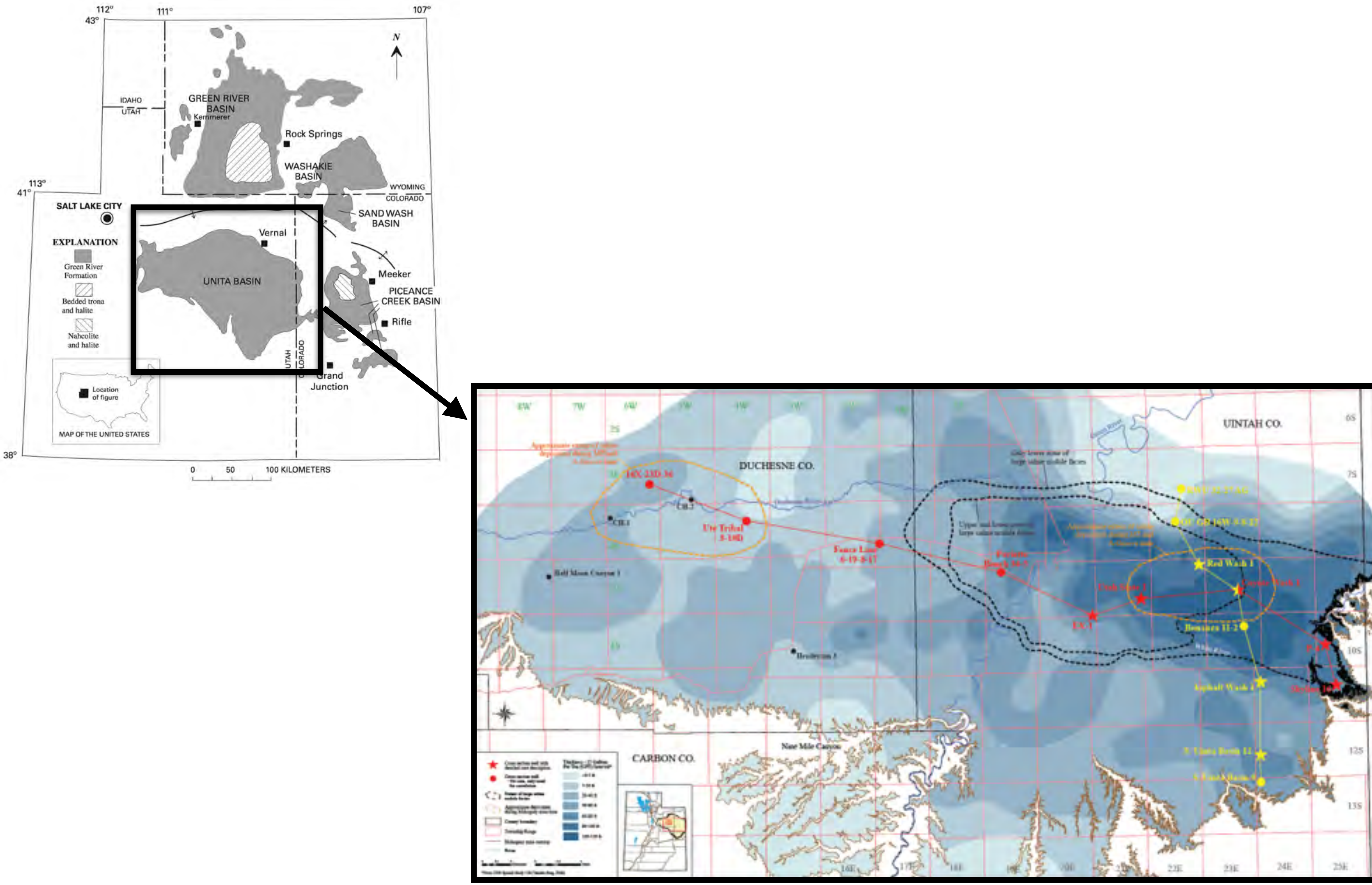




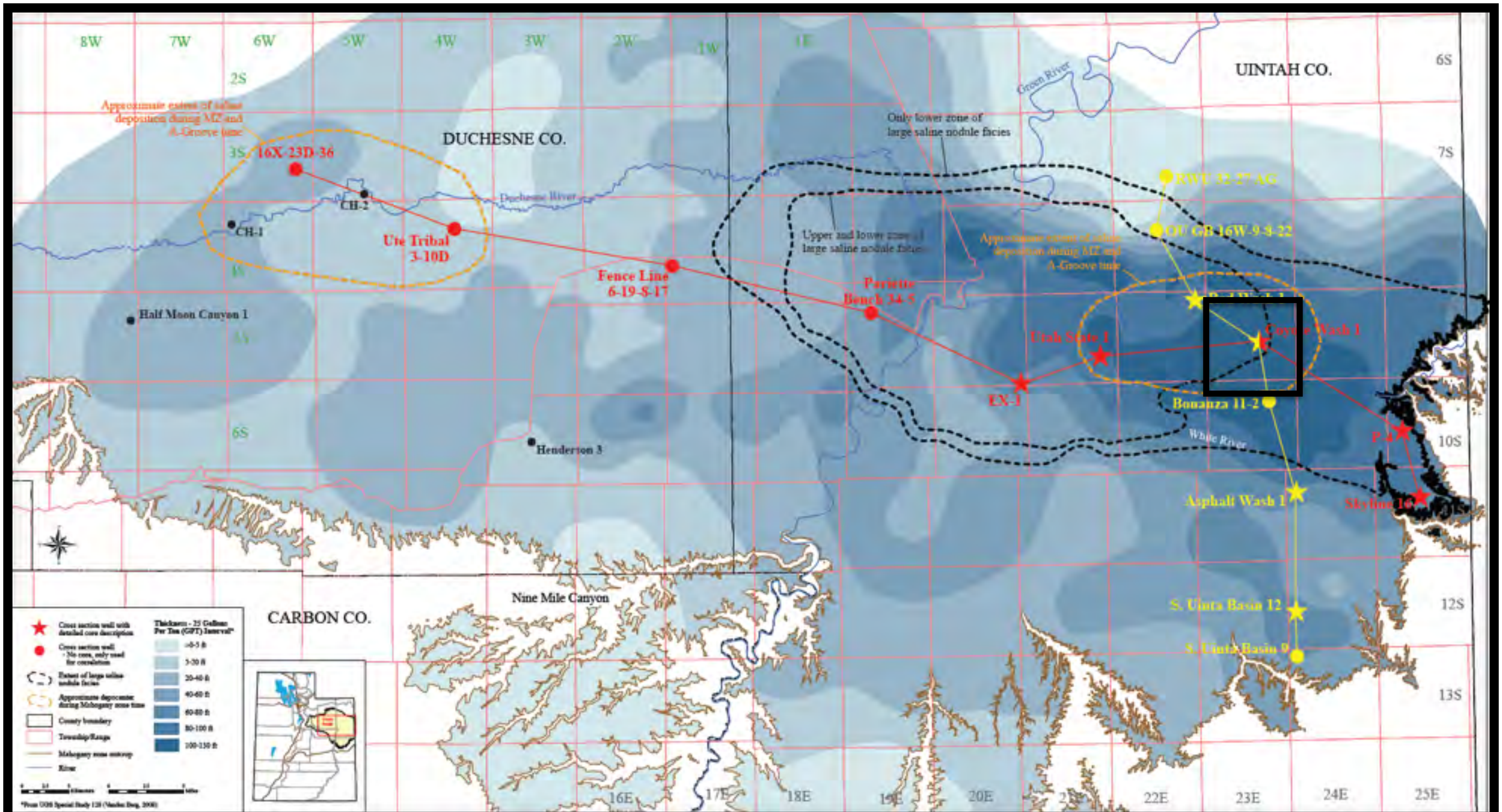
vs. 17 Bakken

Economicaly
Viable

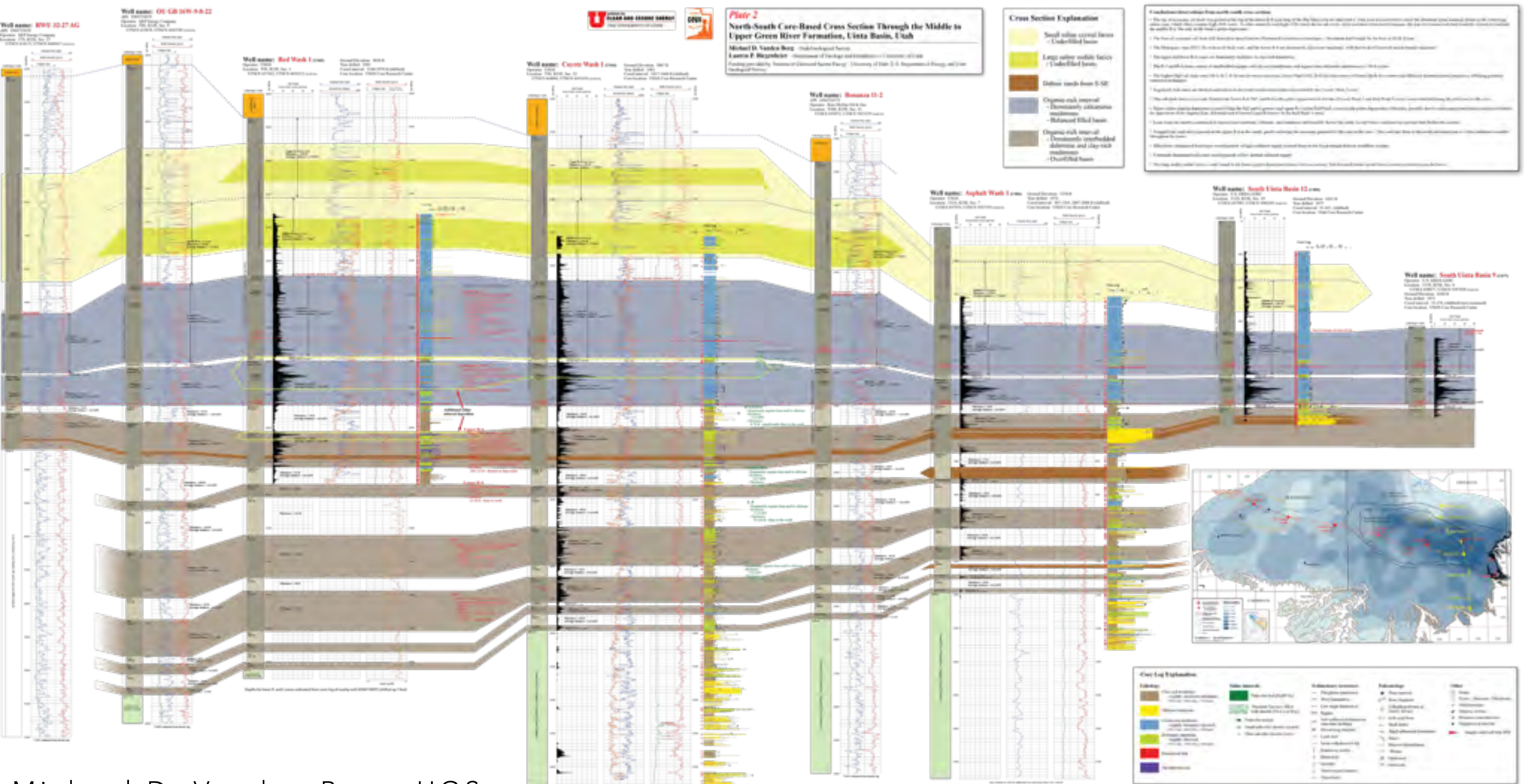
Uinta Basin, UT



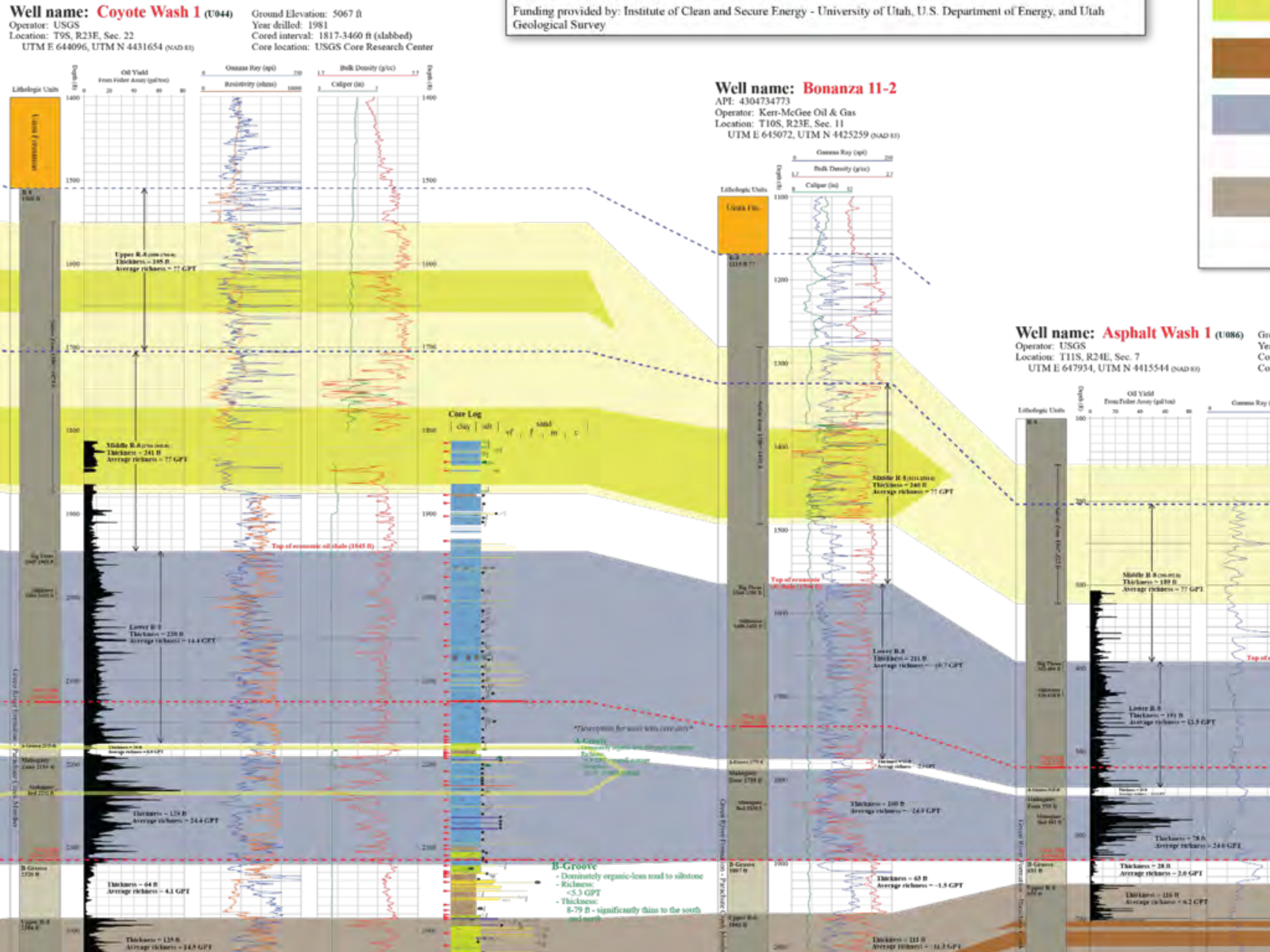
Uinta Basin, UT



Uinta Basin, UT



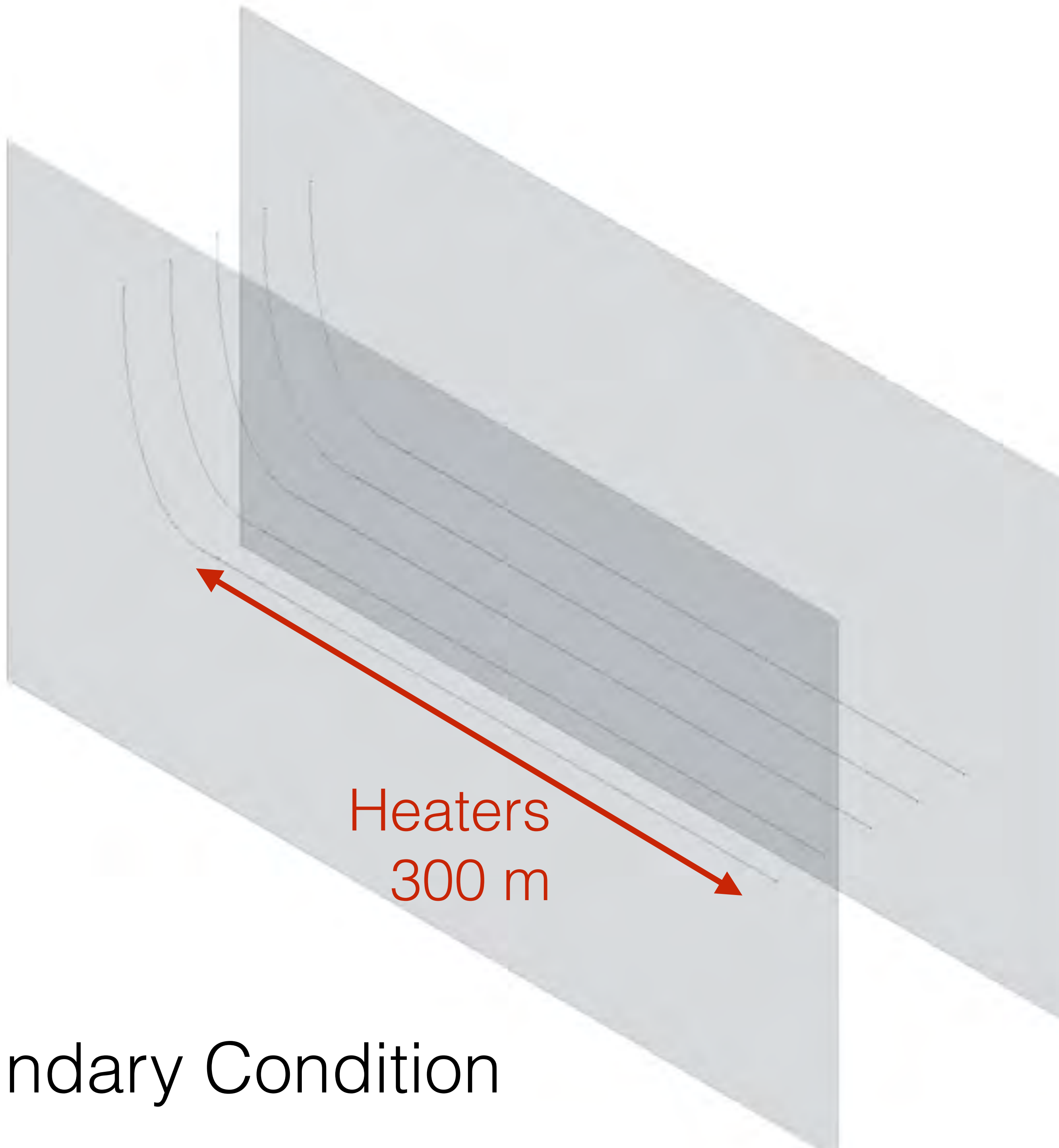
Michael D. Vanden Berg, UGS
Lauren P. Birgenheier, U of U


Well name: Coyote Wash 1 (U044)
Operator: USGS
Location: T9S, R23E, Sec. 22
UTM E 644096, UTM N 4431654 (NAD 83)
Ground Elevation: 5067 ft
Year drilled: 1981
Cored interval: 1817-3460 ft (slabbed)
Core location: USGS Core Research Center
Funding provided by: Institute of Clean and Secure Energy - University of Utah, U.S. Department of Energy, and Utah Geological Survey
Lithologic Units
Depth (ft)
Oil Yield
From Fisher Assay (gal/ton)
Gamma Ray (api)
Resistivity (ohms)
Bulk Density (g/cc)
Caliper (in)
Uinta Formation
Upper R-8
Thickness ~ 195 ft
Average richness ~ ?? GPT
Middle R-8
Thickness ~ 241 ft
Average richness ~ ?? GPT
Top of economic oil shale (1945 ft)
Lower R-8
Thickness ~ 230 ft
Average richness ~ 14.4 GPT
Core Log
clay
silt
sand
vf
f
m
c
Thickness ~ 128 ft
Average richness ~ 24.4 GPT
Thickness ~ 64 ft
Average richness ~ 4.1 GPT
Thickness ~ 135 ft
Average richness ~ 24.5 GPT
Green River Formation - Parachute Creek Member
B-Groove
- Dominately organic-lean mud to siltstone
- Richness:
<5.3 GPT
- Thickness:
8-79 ft - significantly thins to the south and north
Well name: Bonanza 11-2
API: 4304734773
Operator: Kerr-McGee Oil & Gas
Location: T10S, R23E, Sec. 11
UTM E 645072, UTM N 4425259 (NAD 83)
Gamma Ray (api)
Bulk Density (g/cc)
Caliper (in)
Uinta Fm.
Middle R-8
Thickness ~ 240 ft
Average richness ~ ?? GPT
Top of economic oil shale
Lower R-8
Thickness ~ 211 ft
Thickness ~ 160 ft
Thickness ~ 63 ft
Average richness ~ 1.5 GPT
Thickness ~ 111 ft
Well name: Asphalt Wash 1 (U086)
Operator: USGS
Location: T11S, R24E, Sec. 7
UTM E 647934, UTM N 4415544 (NAD 83)
Oil Yield
From Fisher Assay (gal/ton)
Middle R-8
Thickness ~ 189 ft
Average richness ~ ?? GPT
Lower R-8
Thickness ~ 191 ft
Average richness ~ 12.5 GPT
Thickness ~ 78 ft
Average richness ~ 24.0 GPT
Thickness ~ 28 ft
Average richness ~ 2.0 GPT
Thickness ~ 126 ft
Average richness ~ 6.2 GPT

Geometry Domain

Geometry Domain

Geometry Domain



Periodic Boundary Condition

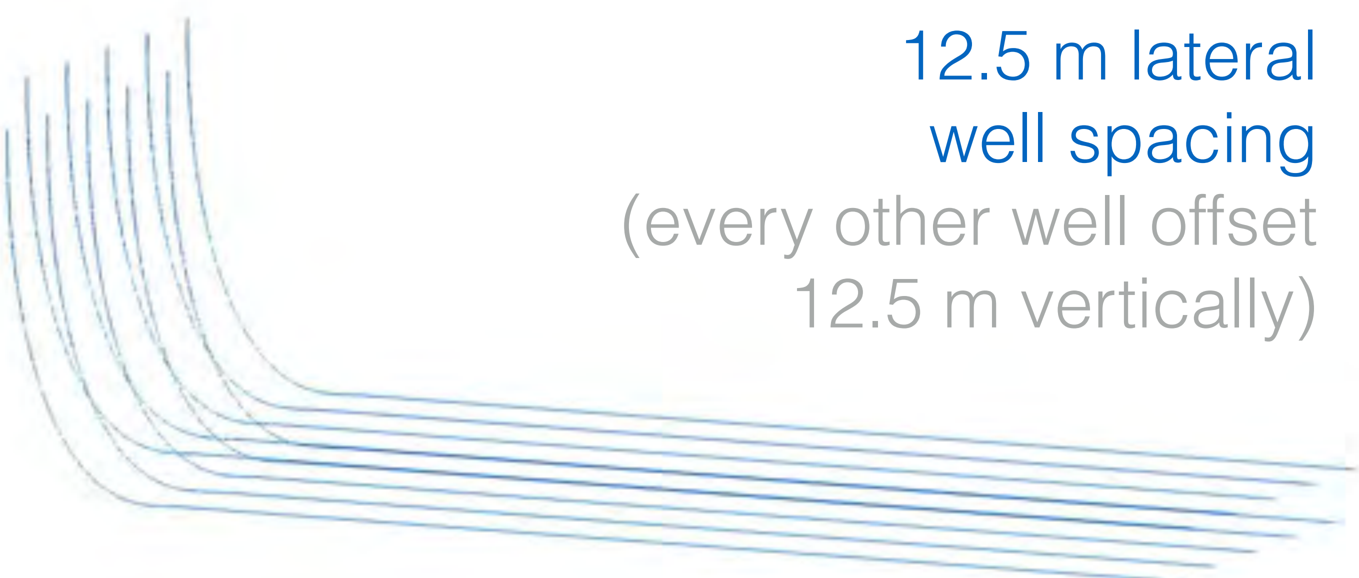
Simulation Settings

25 m lateral well spacing

1

12.5 m lateral well spacing

2

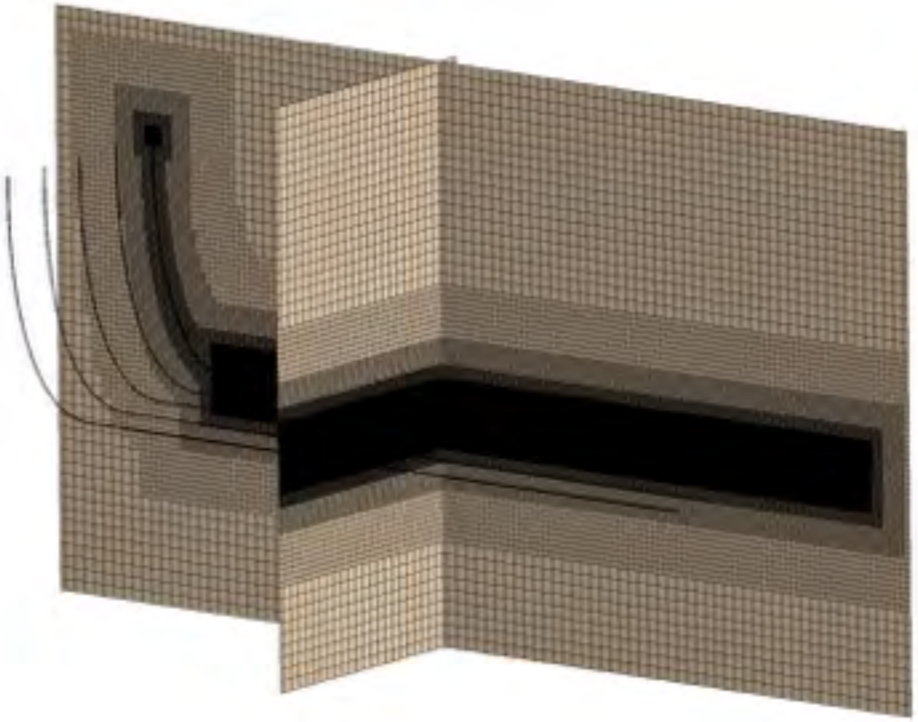


12.5 m lateral well spacing
(every other well offset 12.5 m vertically)

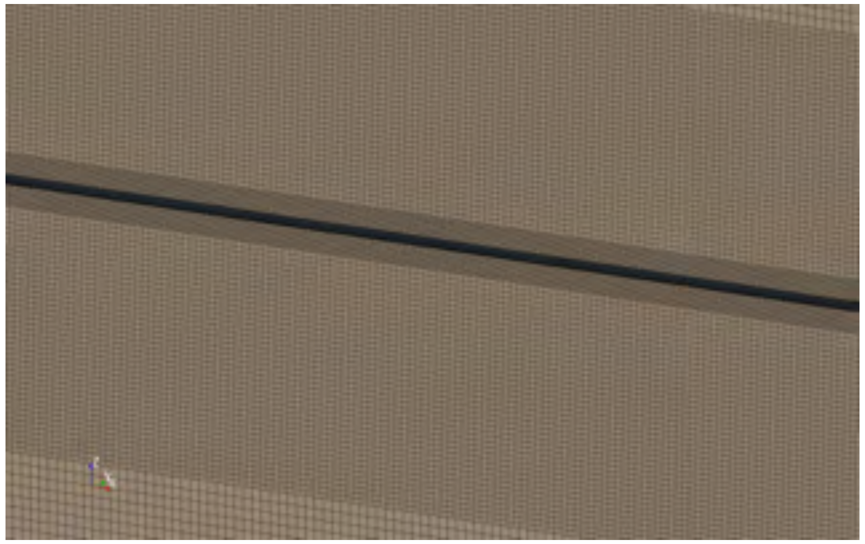
3

- Conduction only
- No collector well inside geometry
  - What is produced is what is collected
- Constant heating temperature 675 K for the entire length of the horizontal well
- Diameter of horizontal well 0.5 m
- Oil shale kinetic parameters based from Uinta Basin sample

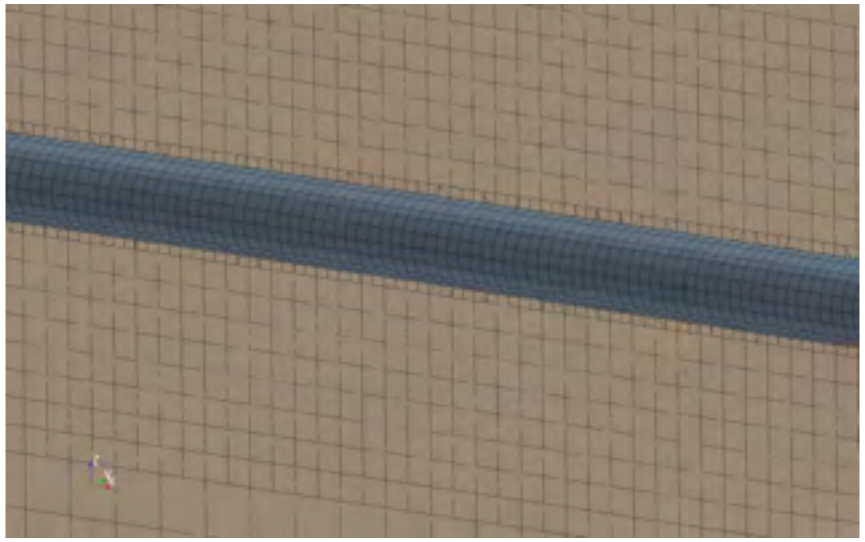
A=9.5e13 1/s E=221 kJ/mol
(Dr. Tom Fletcher, BYU)



Simulation Mesh



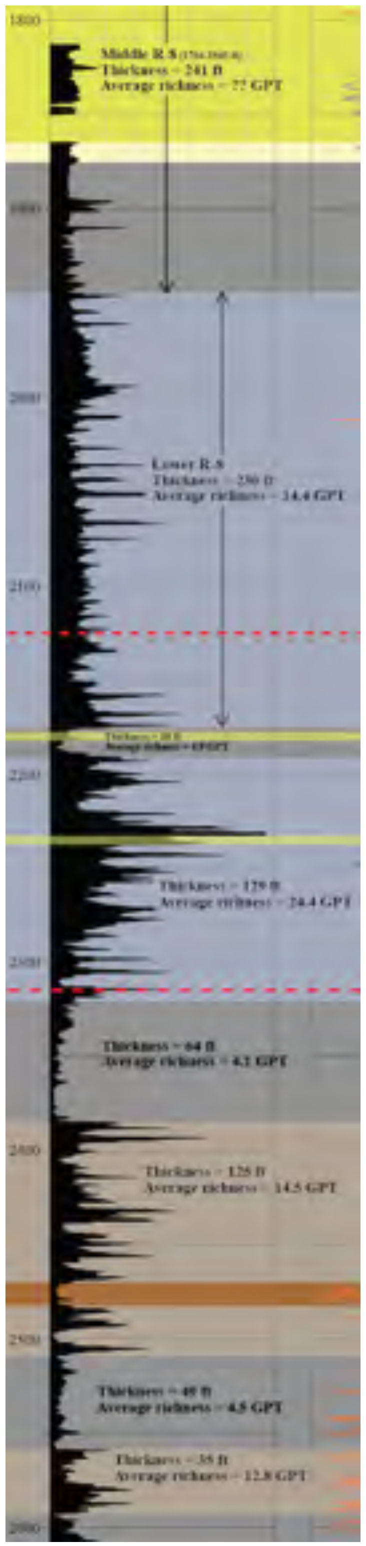
50 mil trimmer cells

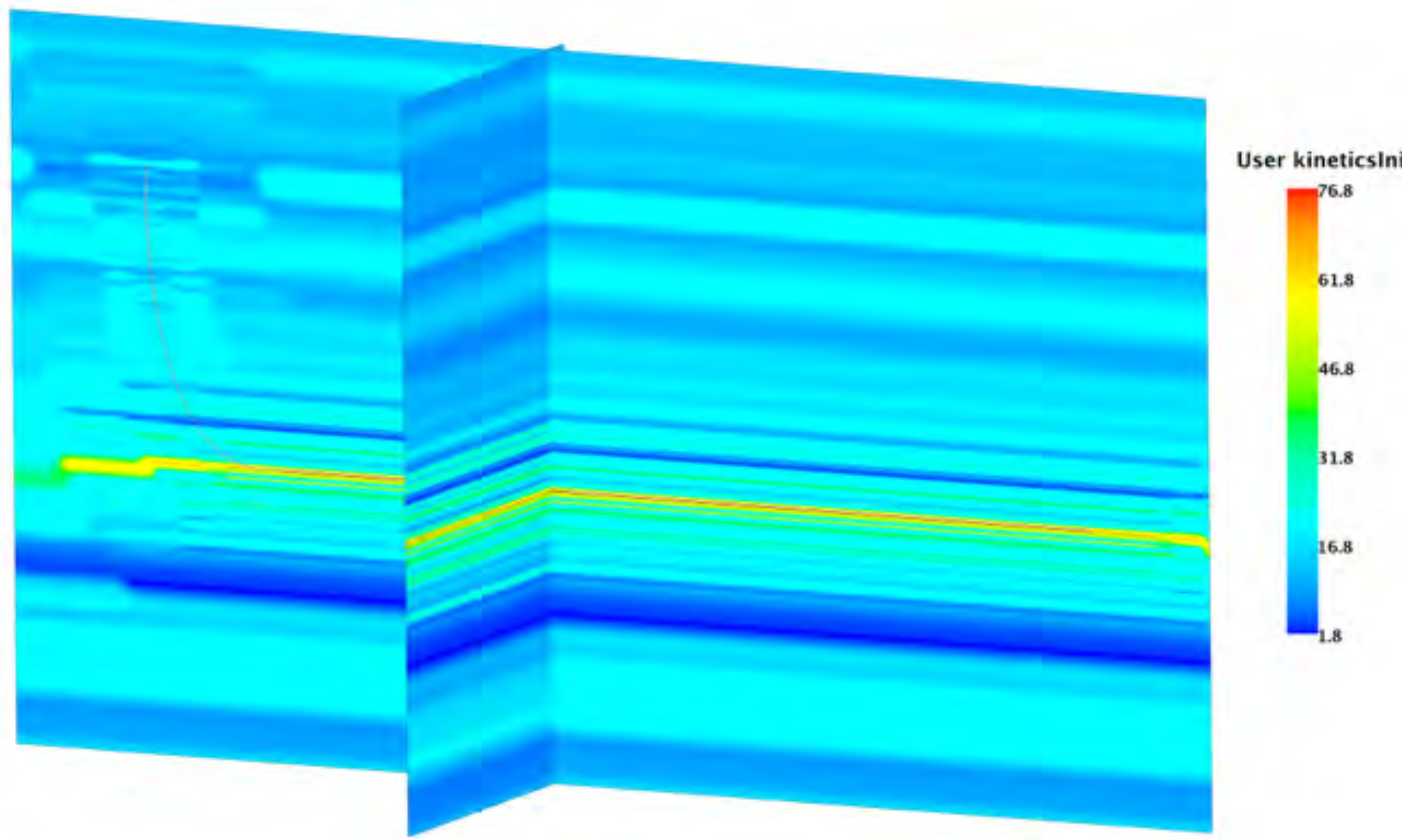


1,200 - 3,000 procs
5 yrs of heating
150,000 CPU-hr/sim
(~260 days on 24-core workstation)

10 cm resolution

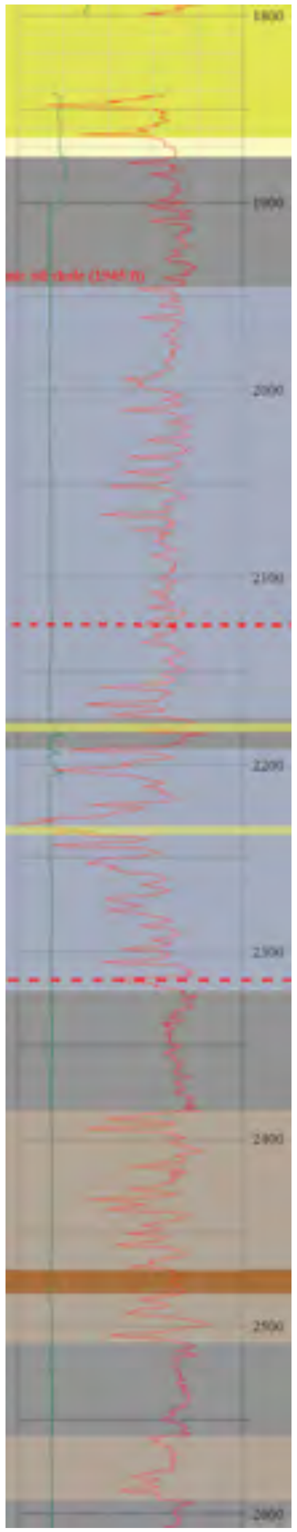
Simulation Properties

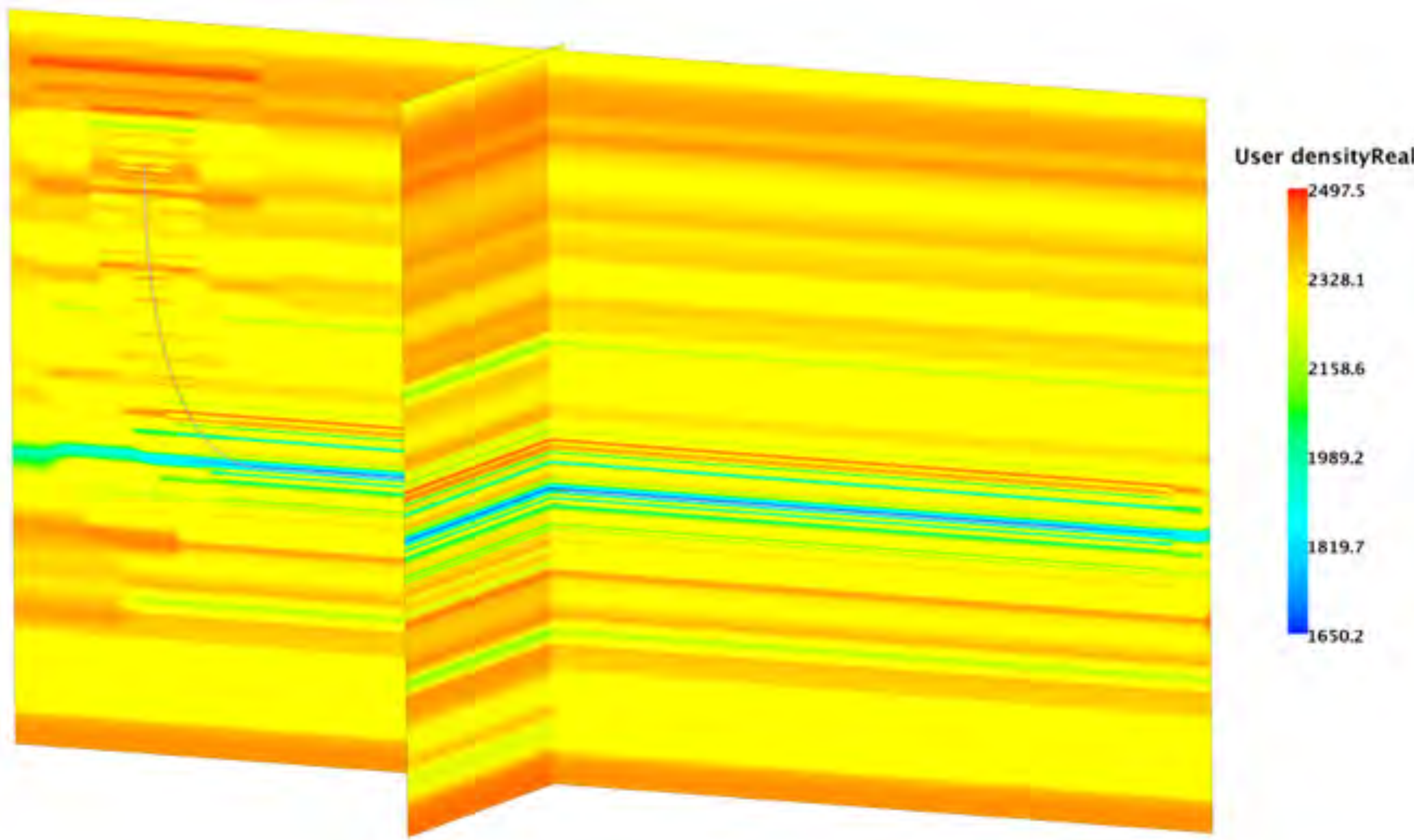




Oil shale grade (GOPT)

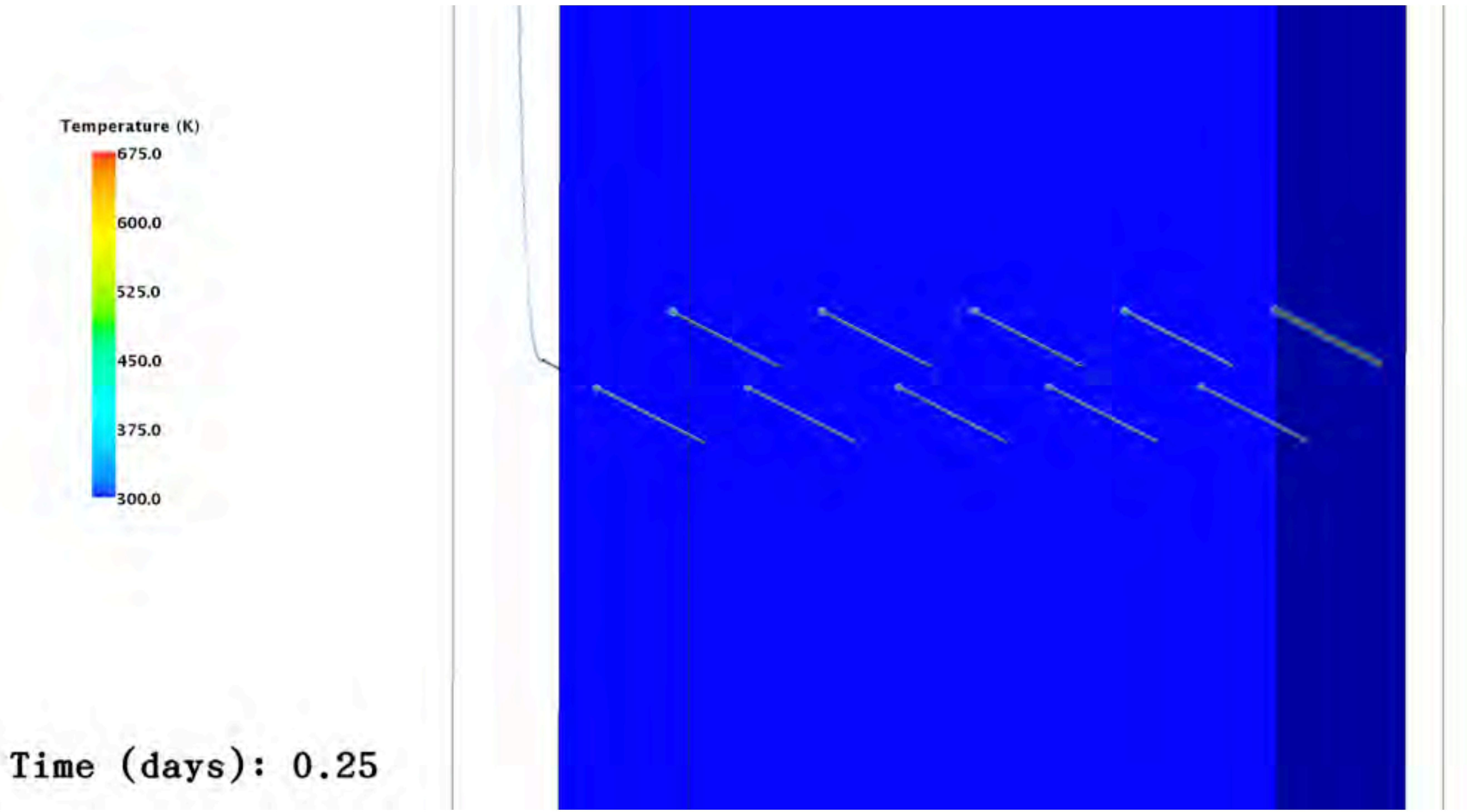
Simulation Properties





Density (kg/m^3)

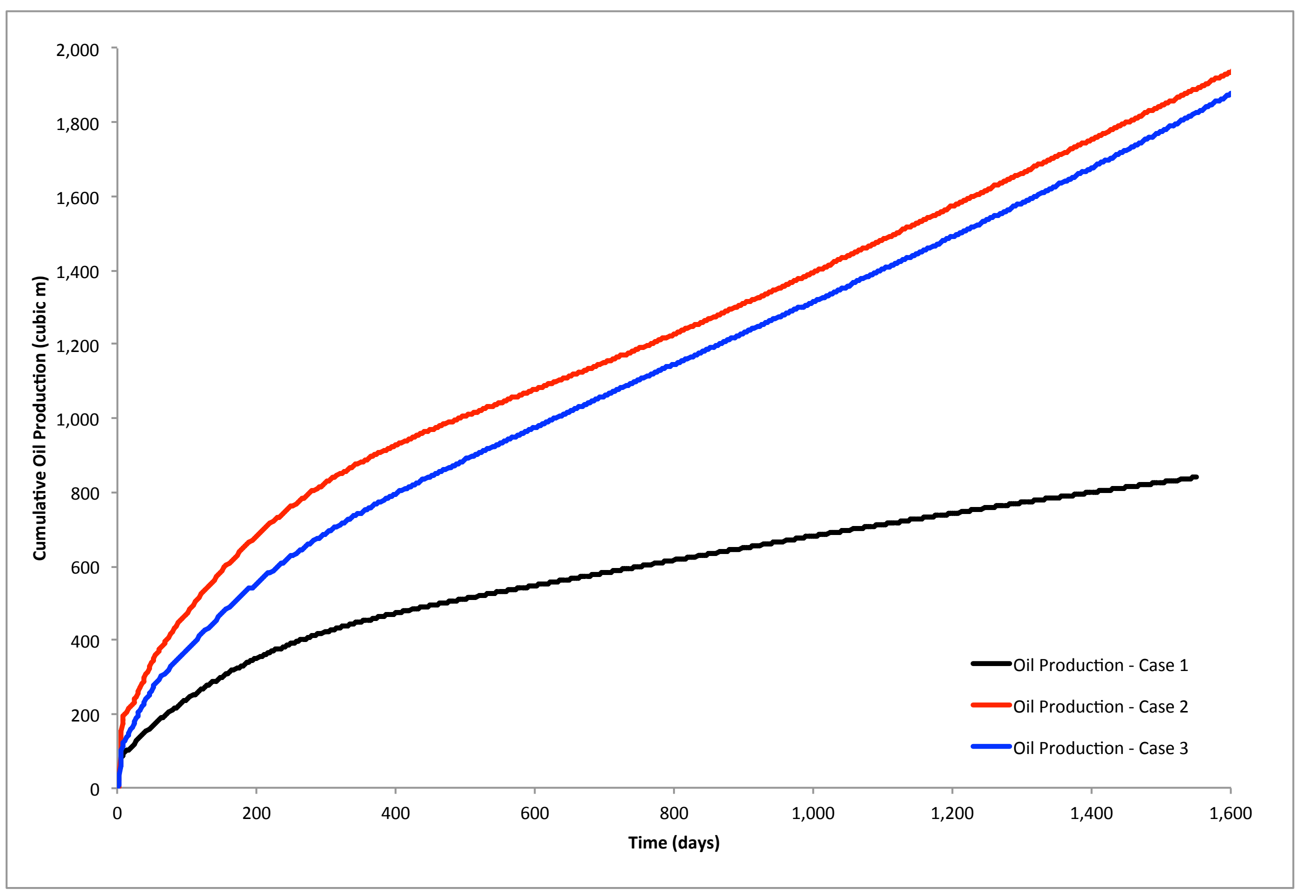
Temperature distribution for Case 3



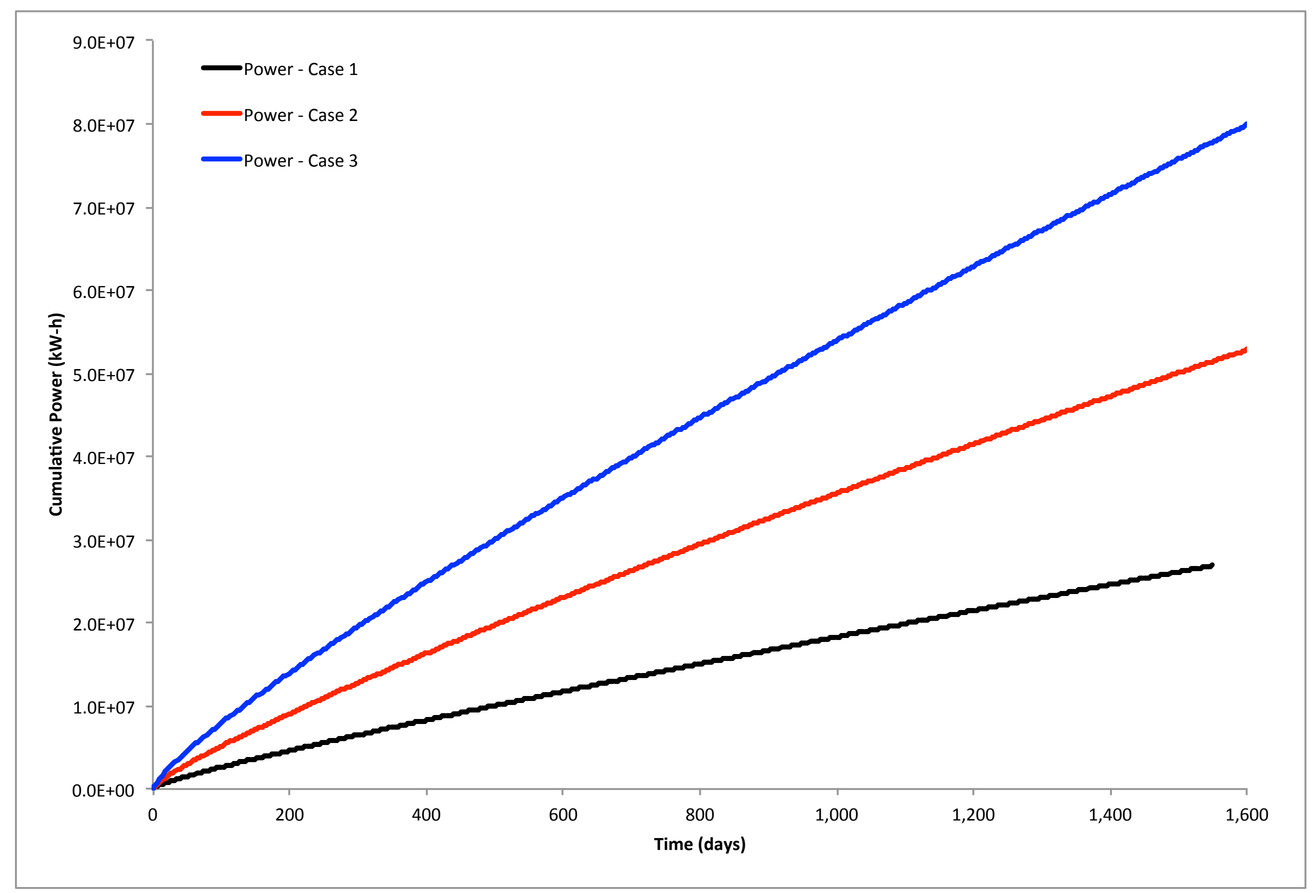
Results: Net Energy Return

$$\text{NER} = \frac{\text{Energy Out}}{\text{Energy In}}$$

Energy Out = Energy contained in product



Energy In = Energy supplied by heaters



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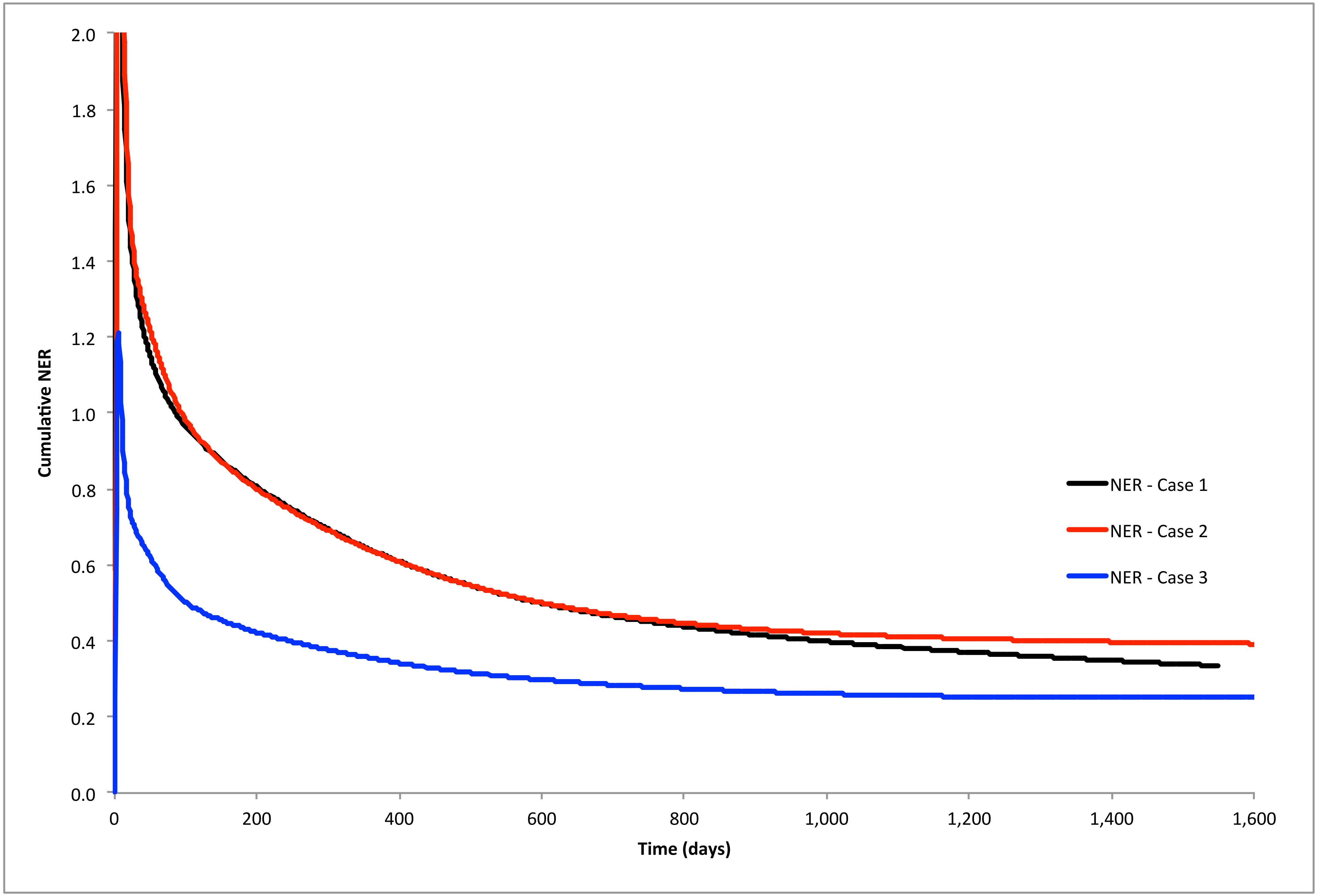
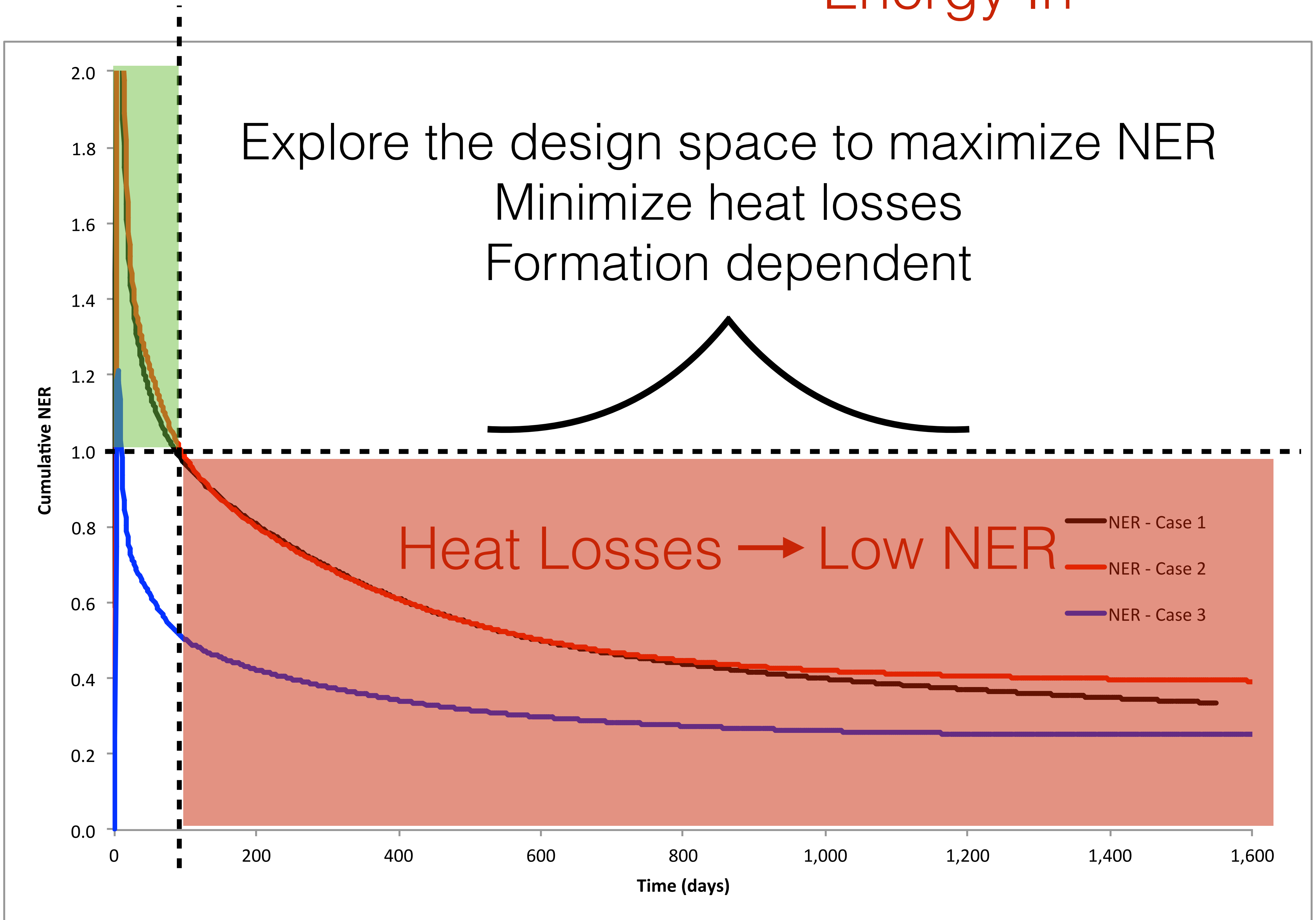
Results: Net Energy Return

$$NER = \text{Energy Out} / \text{Energy In}$$

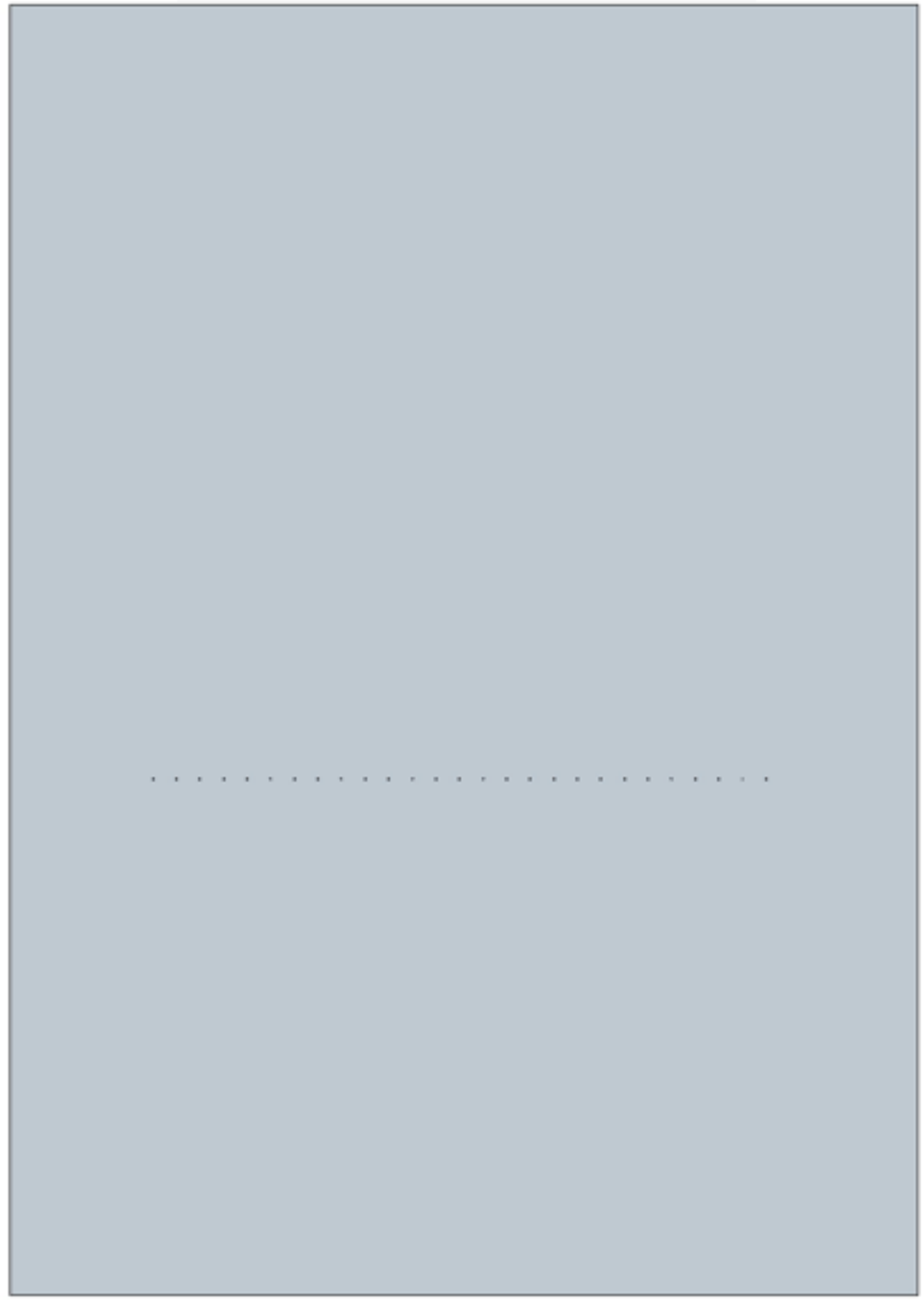


Results: Net Energy Return

NER = Energy Out / Energy In



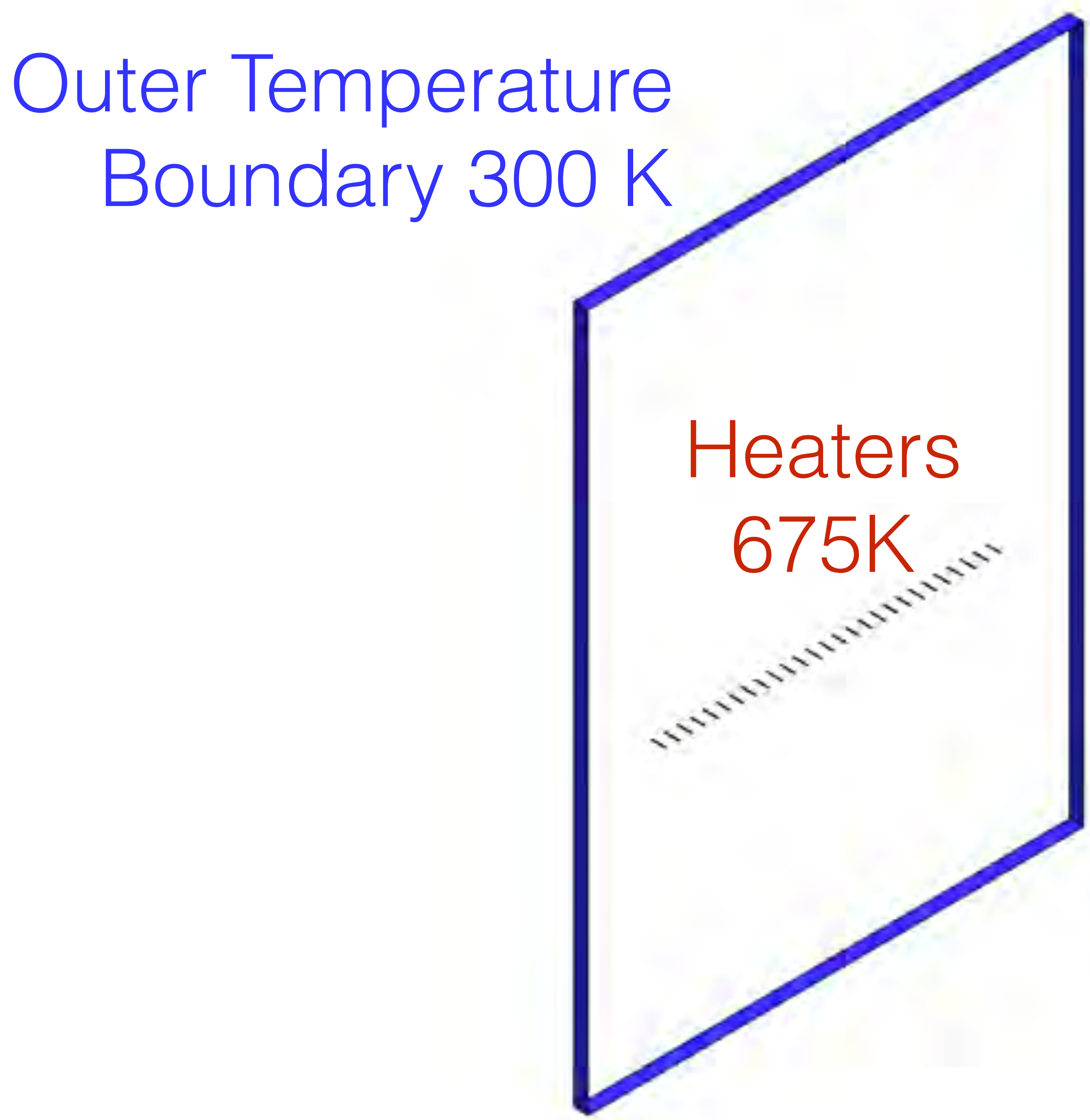
Modified Geometry Domain



Modified Geometry Domain

Periodic Boundary Conditions

Modified Geometry Domain



Setting up Geometry Domain

6 design parameters:

Well radius (0.11 m - 0.25 m)

Lateral well spacing (4.6 - 12.2 m)

Upward well spacing (4.6 - 12.2 m)

Number of well rows (1 -10)

Well offset (0 - 60 degrees)

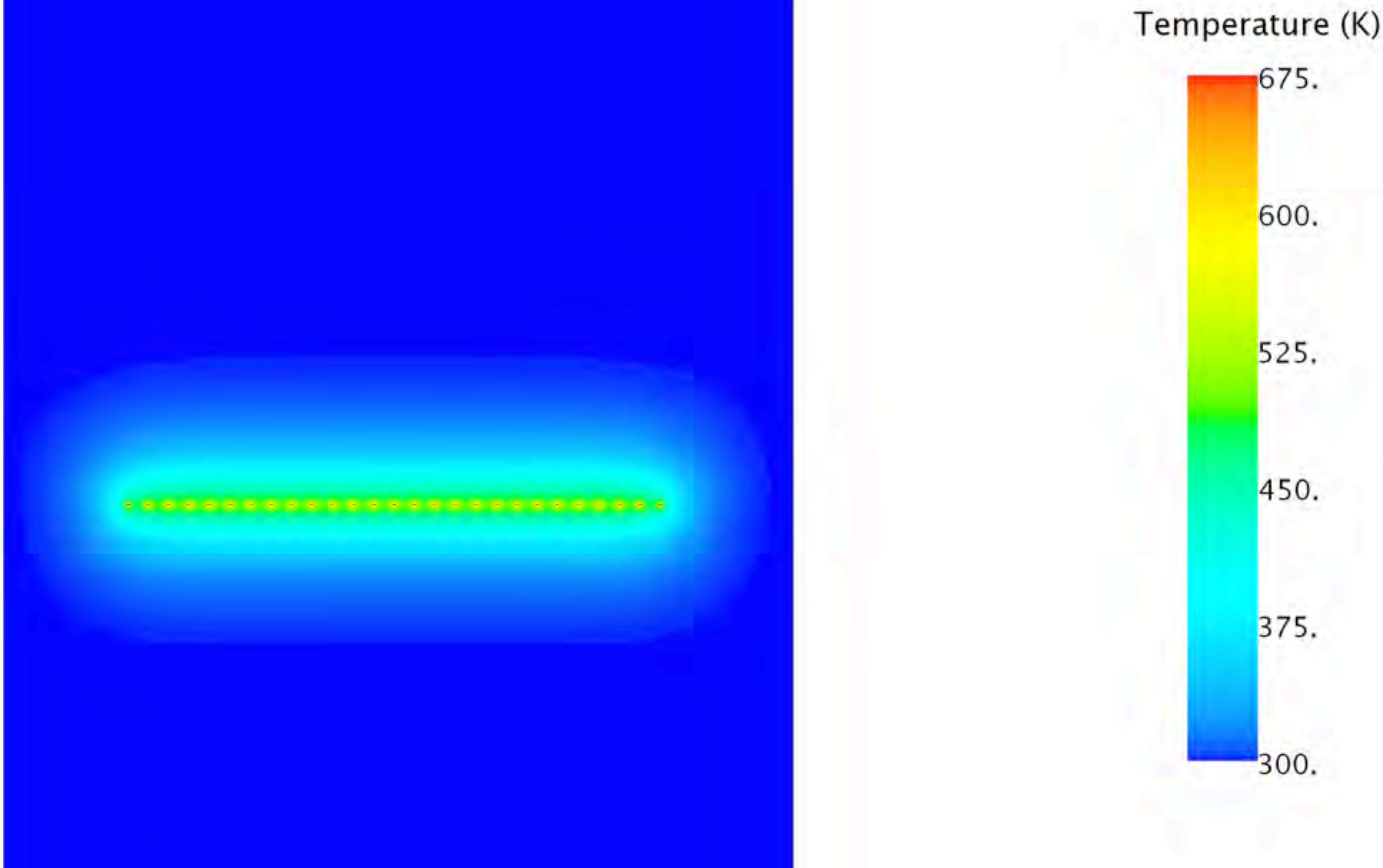
Vertical location (spanning various formation strata)

Multi-objective (Pareto) optimization

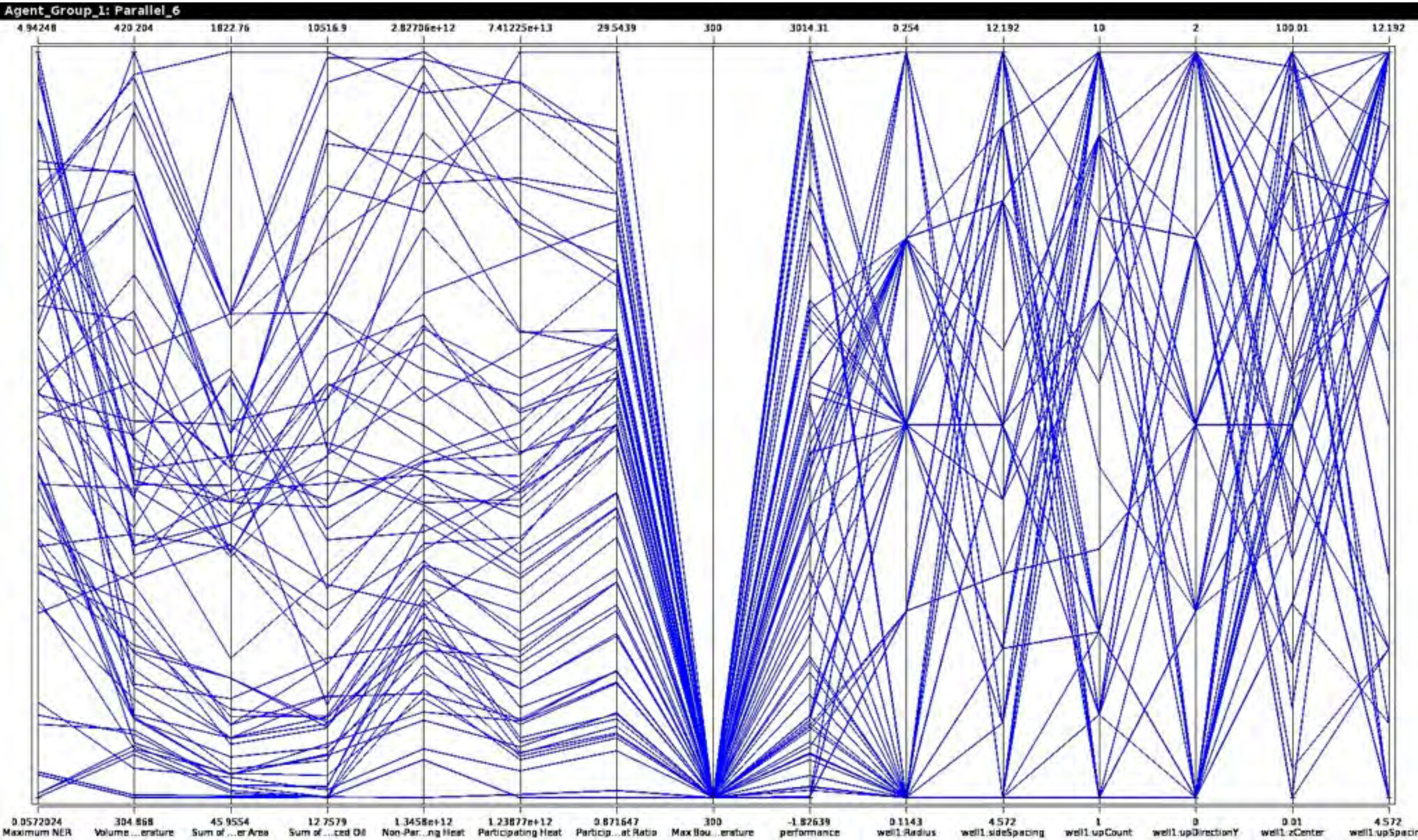
1 - Maximize NER (70 %)
2 - Maximize oil production (20 %)
3 - Minimize well surface area (10 %)

5 years of heating / 64 designs running consecutively / 876 procs per simulation completed over period of 1 week

Temperature Results (after 5 yrs of heating)

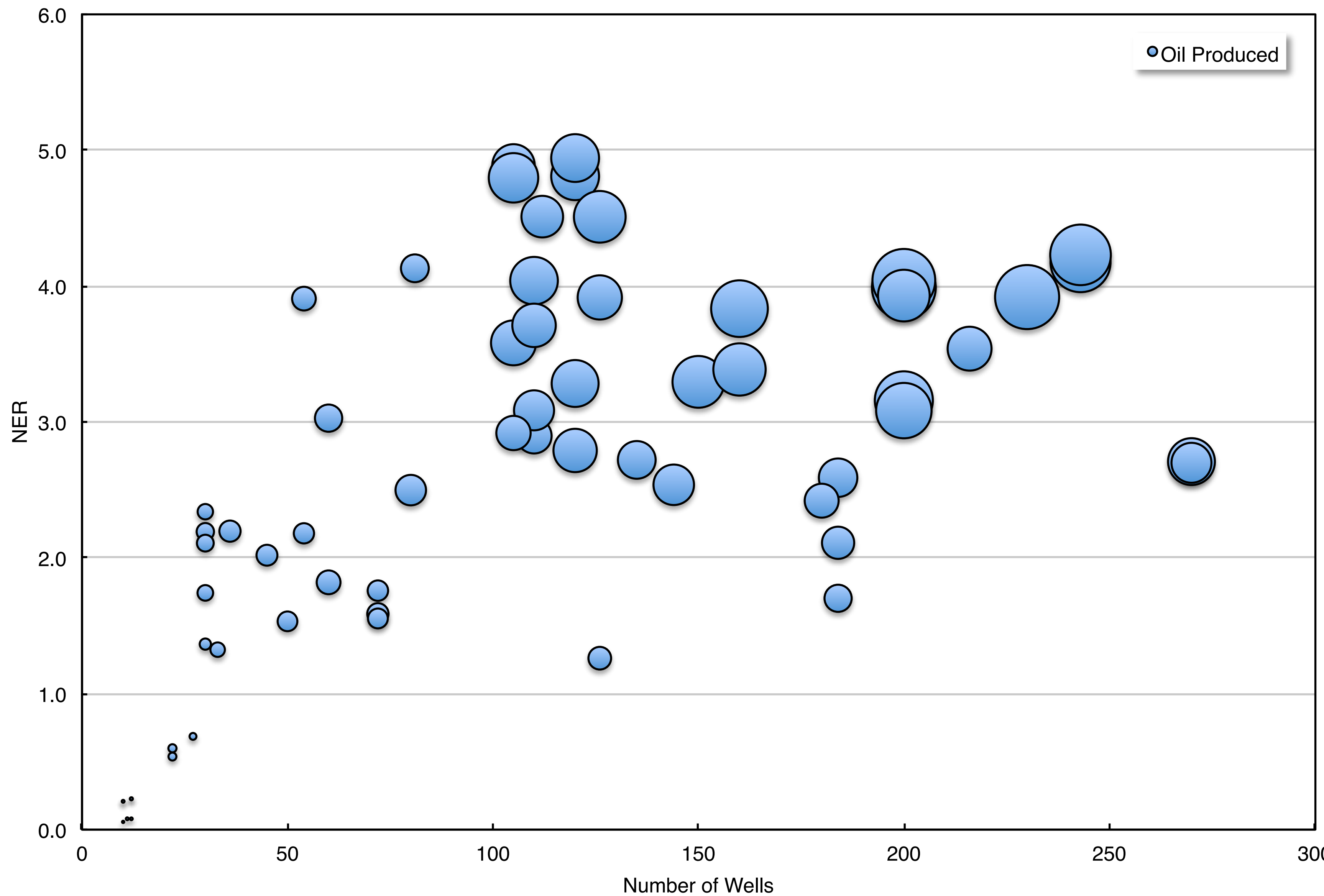


Summary of Results

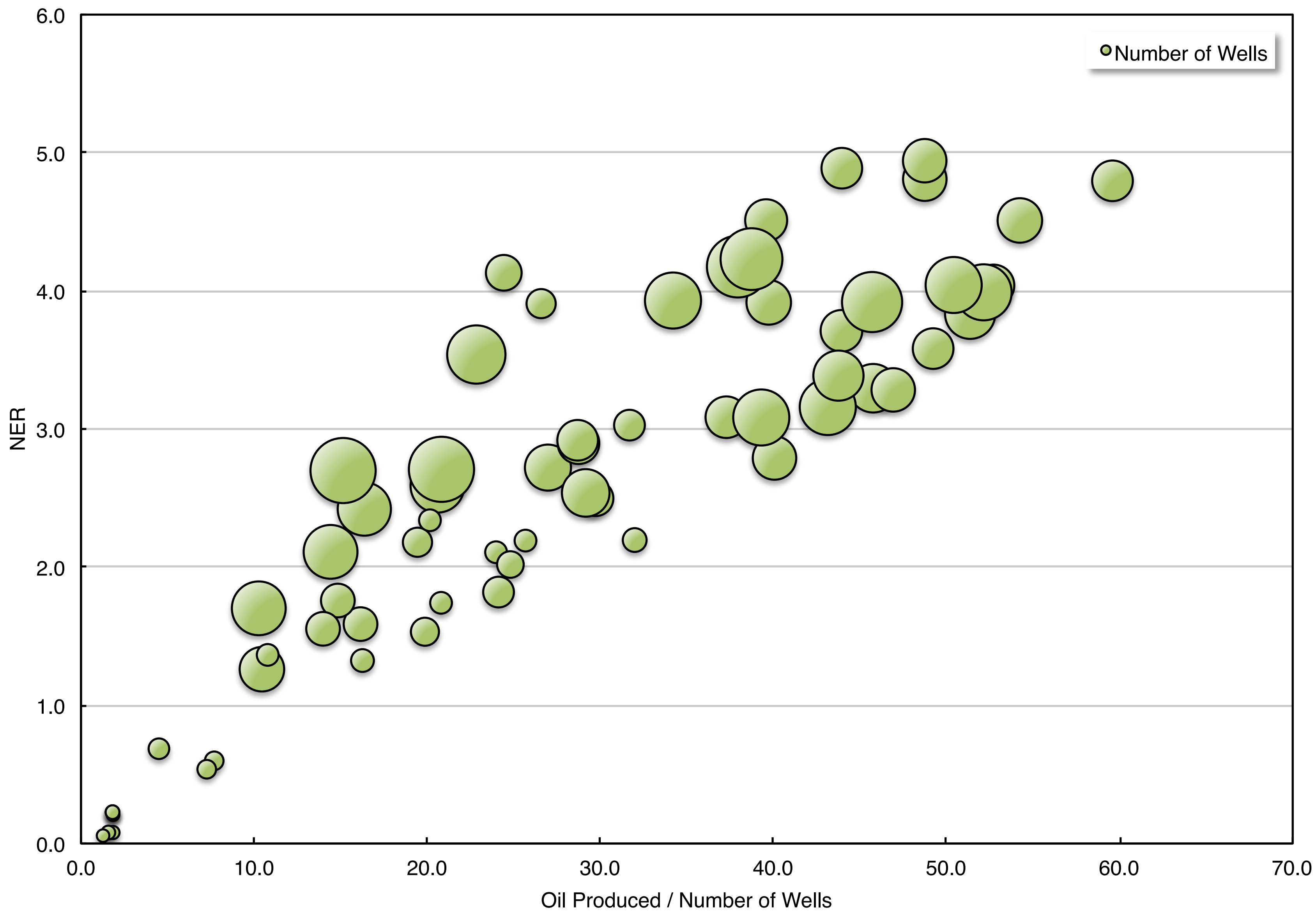


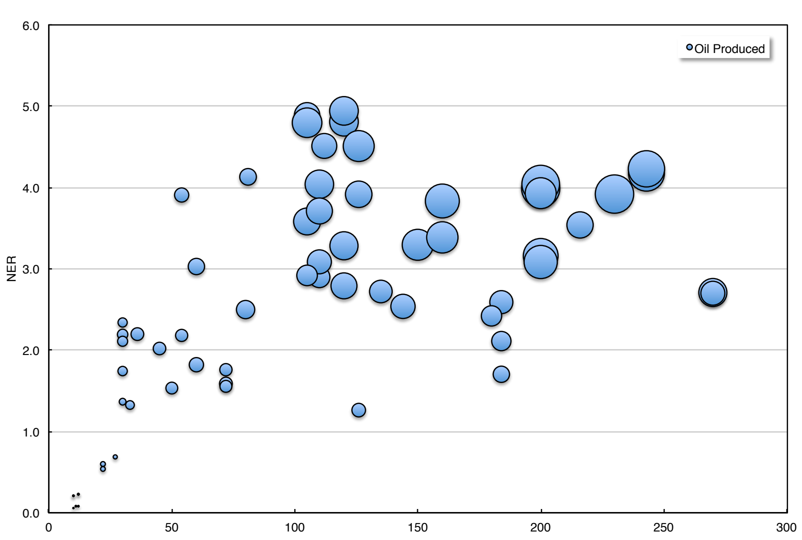
Parallel Plot generated using HEEDS Post

NER Results after 5 yrs heating

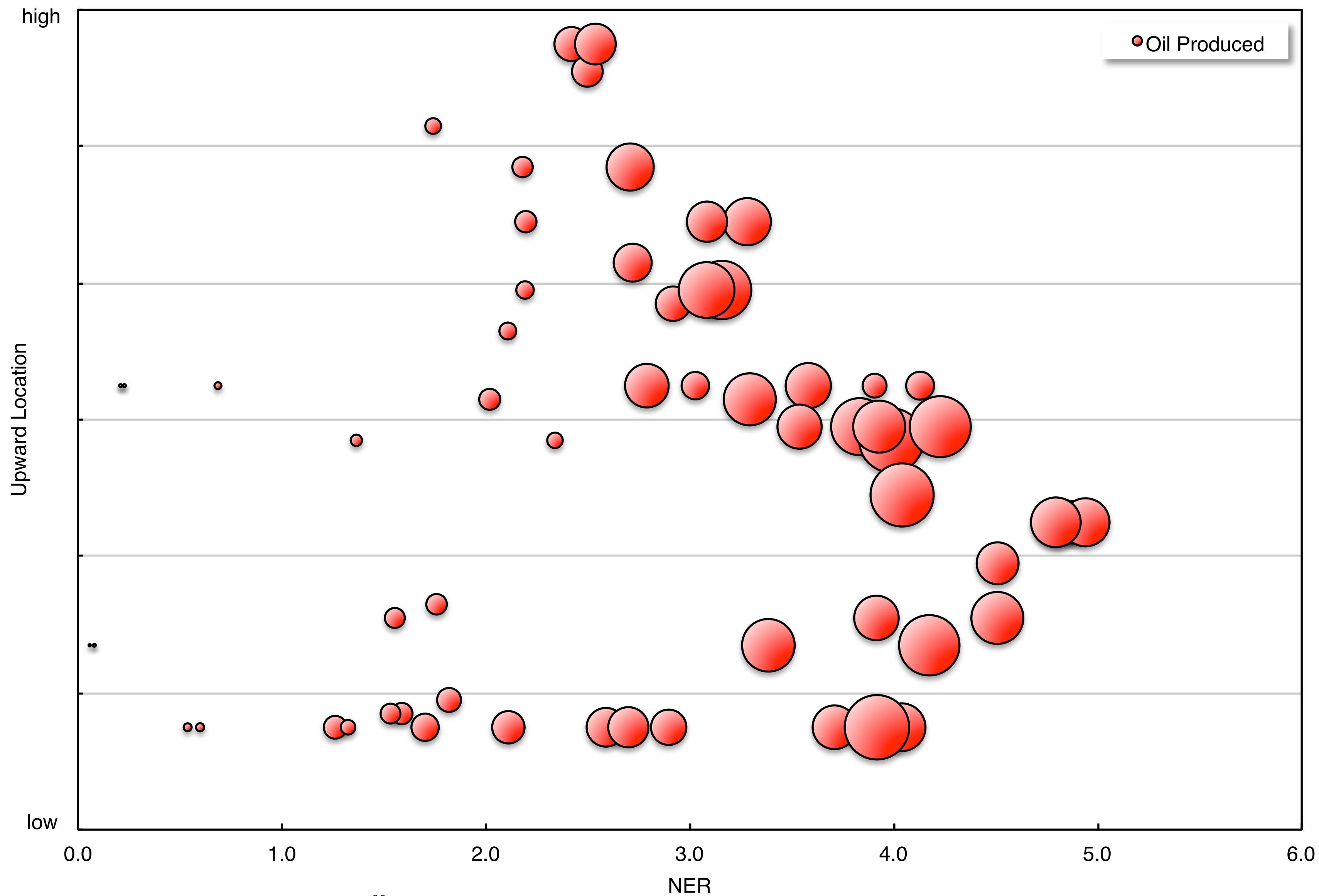


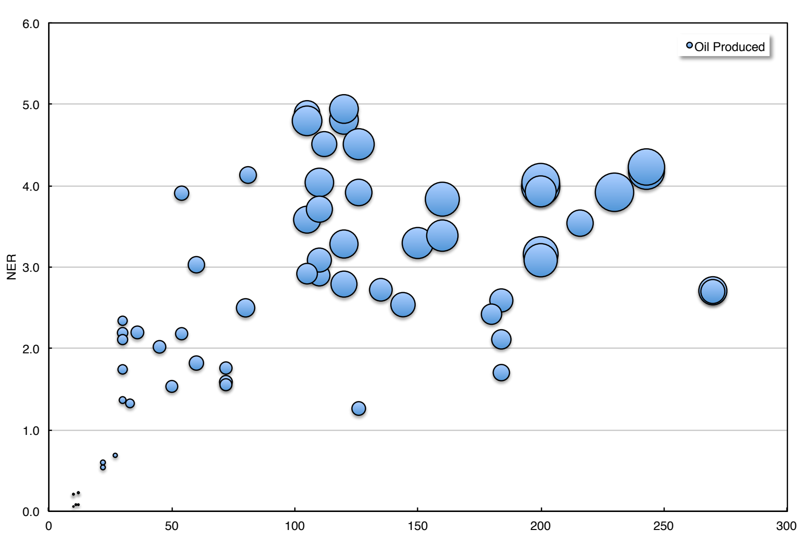
NER Results after 5 yrs heating

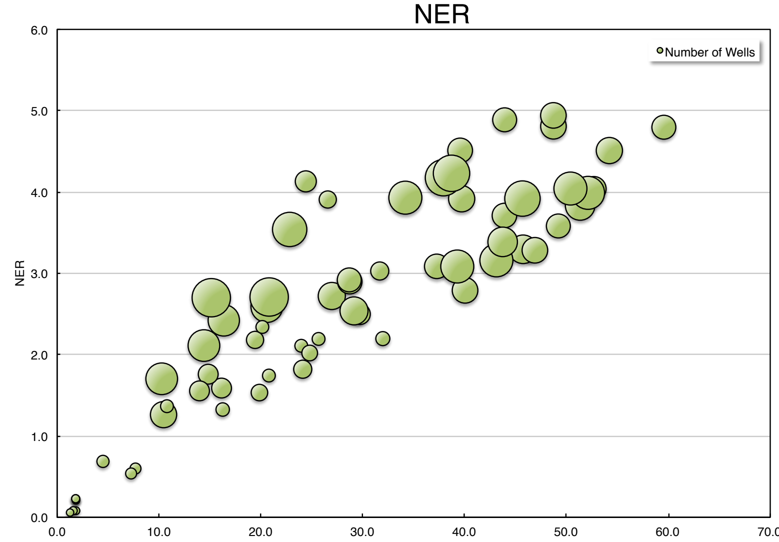




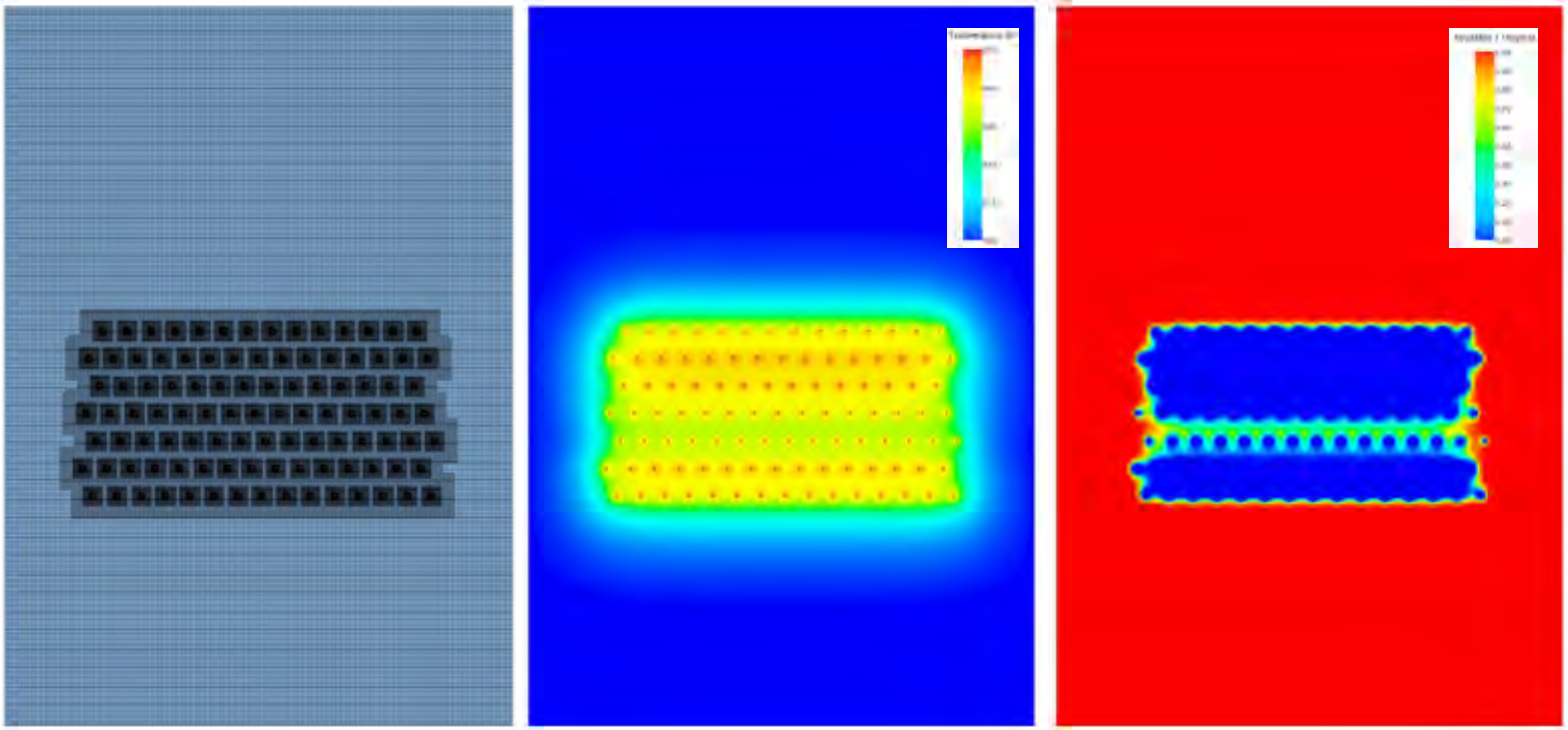
NER Results after 5 yrs heating



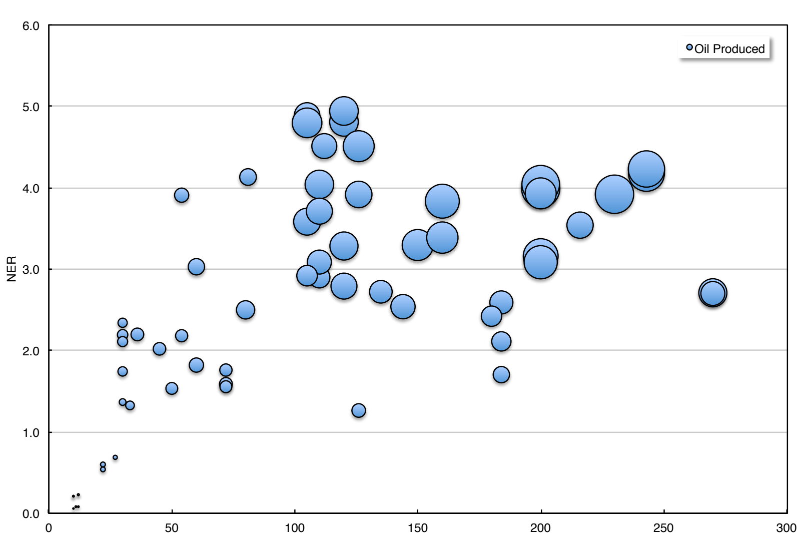


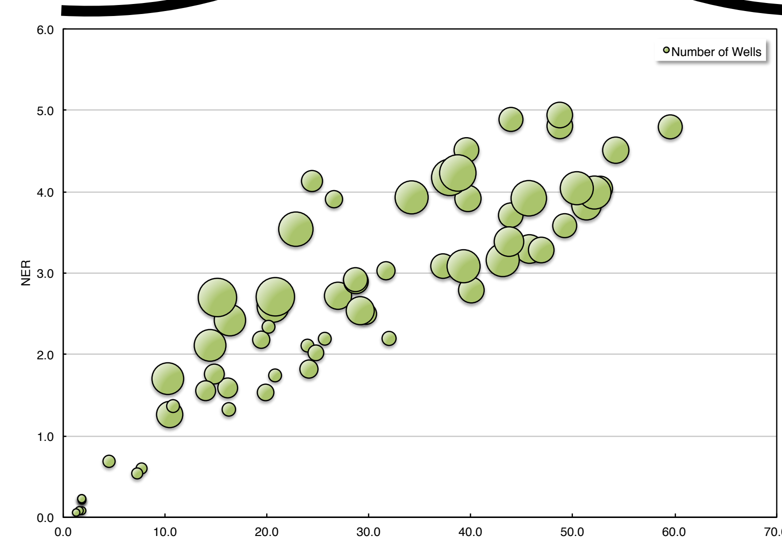


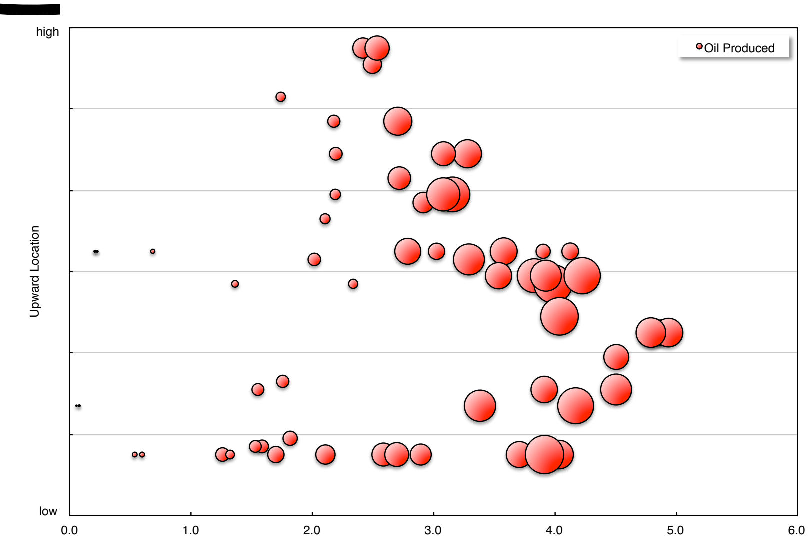
Design 55



Well Radius
0.22 m
Lateral Spacing
8.4 m
Upward Spacing
10.7 m
Number of rows
7
Well offset
27 deg
Vertical Location
70.0 m







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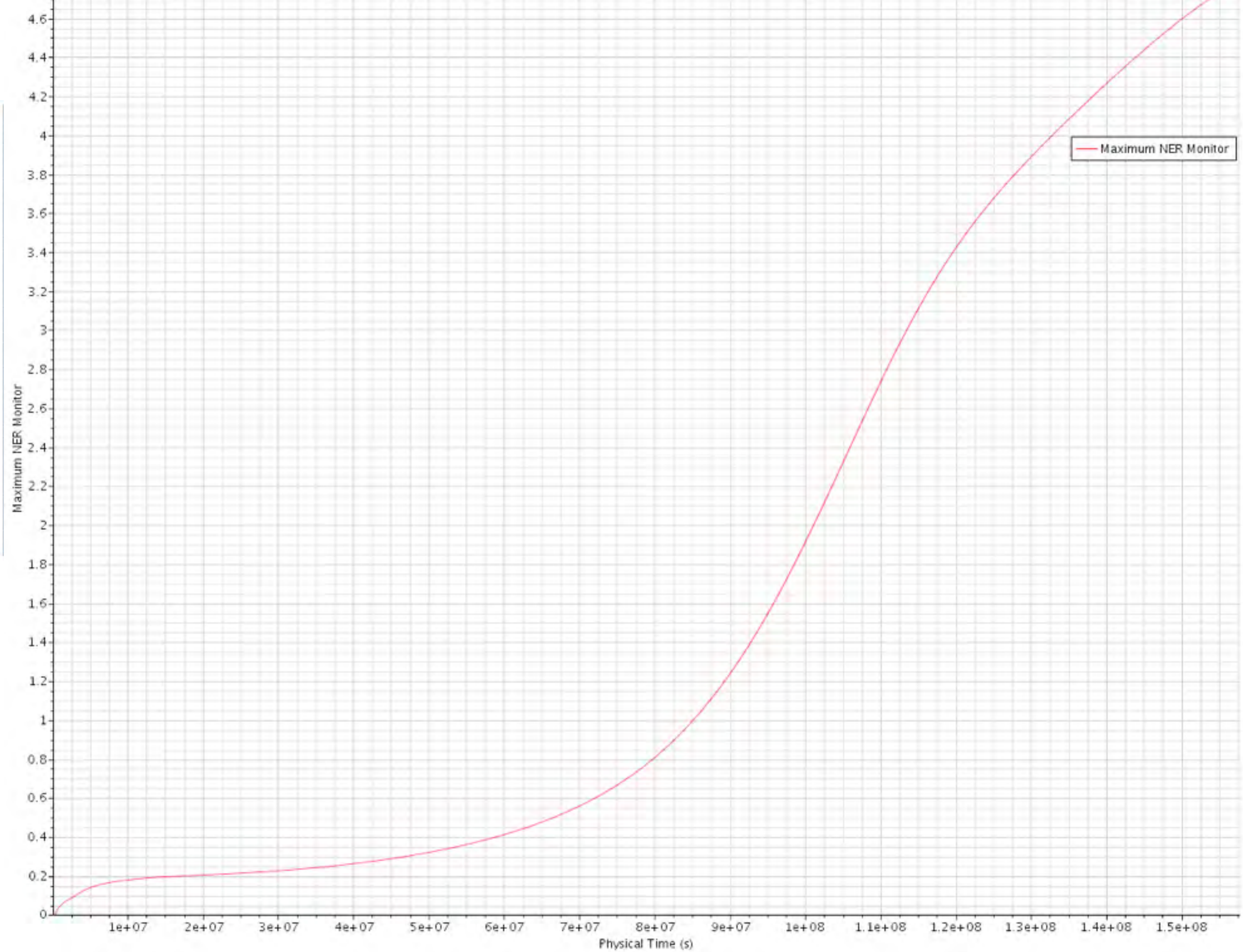

Maximum NER Monitor
Maximum NER Monitor
Physical Time (s)
0
0.2
0.4
0.6
0.8
1
1.2
1.4
1.6
1.8
2
2.2
2.4
2.6
2.8
3
3.2
3.4
3.6
3.8
4
4.2
4.4
4.6
1e+07
2e+07
3e+07
4e+07
5e+07
6e+07
7e+07
8e+07
9e+07
1e+08
1.1e+08
1.2e+08
1.3e+08
1.4e+08
1.5e+08

Conclusions

- Using High Performance Computing capabilities of STAR-CCM+ and Optimate+ explored heat losses occurring during in-situ retorting of oil shale, which is a great potential energy resource
- STAR-CCM+ & Optimate+ can search design space to best utilize the available resources and thus maximize the return on investment
  - 64 designs not sufficient to find optimum for six parameter design space
    - Continuing to search space for the optimum design
  - NER, as implemented, does not contain plant and processing costs
    - Need to be included for overall NER to better understand the economic viability
      - Currently under development

ACKNOWLEDGEMENTS

This project was funded by Department of Energy Assistance Agreement:

"Clean and Secure Energy from Domestic Oil Shale and Oil Sands Resources" DE-FE0001243

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