Oil & Natural Gas Technology

DOE Award No.: DE-FE0001243

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

Quarterly Progress Report
(April - June 2013)

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

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Office of Fossil Energy

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Project Period: October 1, 2010 to September 30, 2013

Prepared for:
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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.

Two significant Task 2 outreach efforts occurred during this quarter. The 2013 Energy Forum was held on April 2, 2013. The forum featured three panelists and a moderator discussing the theme of "How do we move from argument to action". The 2013 University of Utah Unconventional Fuels Conference was held on May 7, 2013. There were two sessions, one focused on the use of simulation in unconventional fuels development and the other on constraints to development. Each session featured brief presentations from the panelists followed by a question and answer period. Conference attendance (130+) exceeded that of all previous conferences.

For Subtask 3.1, researchers used results from the market assessment report (Subtask 6.3) in a life-cycle analysis to determine the impact of oxyfiring on greenhouse gas emissions from unconventional fuels development. The Subtask 3.3 and 3.4 research teams analyzed constraints to both conventional and unconventional oil development, including water availability, regulatory hurdles, and transportation capacity. They also developed a validation and uncertainty quantification (V/UQ) strategy for comparing available data on conventional oil development to model output.

Subtask 4.3 and 4.9 researchers continued the preparation of two joint manuscripts, one related to characterization of three Skyline 16 core segments and the other to kerogen pyrolysis products and modeling. Subtask 4.2 researchers have recreated a model in COMSOL for comparison and validation with the core-scale experiments to see whether the predictions can be improved. Results of this effort will be summarized in an upcoming topical report. The Subtask 4.7 team designed and built a new clamshell heater so that samples can be tested at pyrolysis temperatures and deformation can be measured in three orthogonal directions. Subtask 4.1 researchers modified the generalized, rubblized shale bed geometry by replacing the pipe heating element with a planar heating element. They also successfully addressed meshing difficulties encountered previously to create a mesh that captures heat transfer not only through the pieces of shale, but also through the convective channels which are formed between the rubblized pieces of shale. The Subtask 4.8 team has prepared detailed detailed cross sections (both N-S and E-W) of the Green River Formation across the Uinta Basin. All the data associated with this work will be uploaded to the ICSE repository.
Subtask 5.3 involves an analysis of policy and economic issues associated with using simulation to assess environmental impacts. Research on existing judicial and agency approaches for estimating error in simulation methodologies used in context of environmental risk assessment and impacts analysis was augmented in this quarter.

The Market Assessment, which comprises Subtasks 3.1 (Phase I), 6.1, and 6.3, was released on July 5, 2013. The report, which is 339 pages long, may be downloaded from http://www.icse.utah.edu/leftnavid3subleftnavid10subpage115. It is also available on a flash drive by contacting ICSE. The final deliverable for Subtask 6.2, a topical report summarizing the Canadian oil sands experience, has undergone final review and will be released in August 2013.

Task 7 researchers continue to work with American Shale Oil (AMSO). The Subtask 7.1 team began development of "Version 1" of their geomechanical model, which will include AMSO data. Subtask 7.3 researchers completed a progress report on V/UQ of the Generation 1 simulation with AMSO experimental data (attached as Appendix C). They also developed a relationship for density as a function of grade and began simulations of AMSO's March 2013 heater experiment.

PROGRESS, RESULTS, AND DISCUSSION

Task 1.0 - Project Management and Planning

During this quarter, there were no schedule/cost variances or other situations requiring updating/amending of the Project Management Plan (PMP). Internal budgeting reallocation occurred during this quarter as described under Task 7.0. Submission of a no cost time extension has been delayed until the first quarter of 2014.

Task 2.0 -Technology Transfer and Outreach

Task 2.0 focuses on outreach and education efforts and the implementation of External Advisory Board (EAB) recommendations. As noted last quarter, the decision has been made to disband the EAB. President David Pershing has not yet communicated this message to EAB members but will do so next quarter.

A major outreach effort, the 2013 University of Utah Unconventional Fuels Conference, was held on May 7, 2013. The conference agenda is attached as Appendix A. The conference had a different format this year. There were two themes with speakers and a moderated panel discussion surrounding each theme. The two themes were: (1) role of simulation in unconventional fuels development and (2) constraints on unconventional fuels development. Professor Philip Smith moderated the panel on simulation while Research Associate Professor Jennifer Spinti moderated the panel on constraints. Questions for the panels came from the moderators and from the audience. Attendance exceeded 130, which is the highest attendance to date for this annual conference. The conference was covered by local news outlets as well as online reporters.

Another outreach effort, the 2013 Energy Forum, was held on April 2, 2013, on the University of Utah campus. The focus of this year's forum was "How do we move from argument to action?" regarding climate change, regional energy demand, natural resources, national energy security, and economic impacts. The forum moderator was Lincoln Davies, Professor of Law, University of Utah. Panelists included Professor Andrew Jorgenson, Department of Sociology, University of Utah, Mr. Matthew Rush, West Regional Business Development Manager, Chevron Energy Solutions, and Mr. Cody Stewart, Governor's Energy Advisor for the State of Utah. An announcement of the event is included as Appendix B.

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>

(Phase I) Status of joint publication deliverable

During this quarter, the project team focused on revisions to the greenhouse gas (GHG) and energy return on invested (EROI) calculations that were needed to address final refinements to the scenarios in Subtask 6.3. They also completed a draft paper on the use of oxyfiring to meet a low-carbon fuel standard for transportation fuels produced from Utah unconventional fuels. The team is currently making final revisions to this paper and expects to submit it to the International Journal of Greenhouse Gas Control in August 2013. Highlights of this evaluation follow.

This study focused on the use of oxyfiring with CO_2 capture in the production, upgrading and refining life-cycle stages of liquid transportation fuels produced from oil shale and oil sands in

Utah's Uinta Basin. The objective of the study is to evaluate the potential of oxyfiring to reduce life-cycle GHG emissions from these types of transportation fuels. It used a simplified process model life-cycle assessment approach to determine well-to-pump (WTP) and well-to-wheel (WTW) GHG emissions associated with the production of conventional gasoline from three potential development scenarios in Utah's Uinta Basin: in situ oil shale, ex situ oil shale, and ex situ oil sands. These scenarios are described in detail in the Subtask 6.3 market assessment report (Hogue *et al.*, 2013). All results are presented on a basis of the lower heating value of conventional gasoline.

Table 1 summarizes the baseline, sensitivity analysis, and oxyfiring cases considered in the analysis, and Figure 1 shows the results of the GHG evaluation for the base case and sensitivity analysis. The bars in Figure 1 on the Canadian oil sands and US crude oil present the range of reported values. The figure illustrates the importance of the extraction and upgrading steps to the life-cycle WTP GHG emissions from unconventional fuels. GHG emissions from transport to the pump are the same for all cases. The GHG contributions associated with transport to the refineries are lower for the Utah cases than either the Canadian oil sands or US conventional crude because the transport distances are shorter.

Table 1. Summary of sensitivity analysis and oxyfiring cases.

	Baseline GHG	Low GHG	High GHG	Oxy (1)	Oxy (2)	Oxy (3)
All scenarios						
Electricity	Utah mix[a]	53% efficient NGCC[b]	Utah mix[a]	Utah mix[a]	Oxyfired NGCC[c]	Oxyfired NGCC[c]
Air separation	d	d	d	d	d	d
Ex situ shale						
Retort process	Tosco II[e]	Tosco II[e]	Paraho[f]	Tosco II[e]	Tosco II[e]	Tosco II[e]
Shale richness	104 l/tonne[g]	146 l/tonne[g]	85.3 l/tonne[g]	104 l/tonne[g]	104 l/tonne[g]	104 l/tonne[g]
Material mined	79,650 tonne/day	56,890 tonne/day	99,790 tonne/day	79,650 tonne/day	79,650 tonne/day	79,650 tonne/day
Refining	9.57 gCO_2e/MJ[h]	7.73 gCO_2e /MJ[h]	11.4 gCO_2e / MJ[h]	9.57 gCO_2e / MJ[h,i]	9.57 gCO_2e / MJ[h,i]	5.74 gCO_2e / MJ[h,i]
In situ shale						
Project life	24-year[j]	40-year[j]	24-year[j]	24-year[j]	24-year[j]	24-year[j]
Initial permeability	20 mD	20 mD	1 mD	20 mD	20 mD	20 mD
Refining	8.67 gCO_2e / MJ[h]	7.00 gCO_2e /MJ[h]	10.3 gCO_2e / MJ[h]	8.67 gCO_2e / MJ[h,i]	8.67 gCO_2e / MJ[h,i]	5.20 gCO_2e / MJ[h,i]
Ex situ sands						
Bitumen	10% saturation	15% saturation	5% saturation	10% saturation	10% saturation	10% saturation
Refining	10.3 gCO_2e / MJ[h]	8.48 gCO_2e /MJ[h]	12.0 gCO_2e / MJ[h]	10.3 gCO_2e / MJ[h,i]	10.3 gCO_2e / MJ[h,i]	6.14 gCO_2e / MJ[h,i]

a EPA (2012); b GHG emissions of 454 g CO_2 e/kWhr (Spath and Mann, 2000); c with CO_2 capture, GHG emissions of 12 g CO_2e/kWhr (Davidson, 2007); d 200kWhr/tonne O_2 (Higginbotham *et al.*, 2011); e Weiss *et al.* (1982); f Cleveland-Cliffs (1976) and Fuel & Mineral Resources (1983); g Vanden Berg (2008); h Gerdes and Skone (2009) and Brandt (2012); i Allam *et al.* (2005); j Hogue *et al.* (2013).

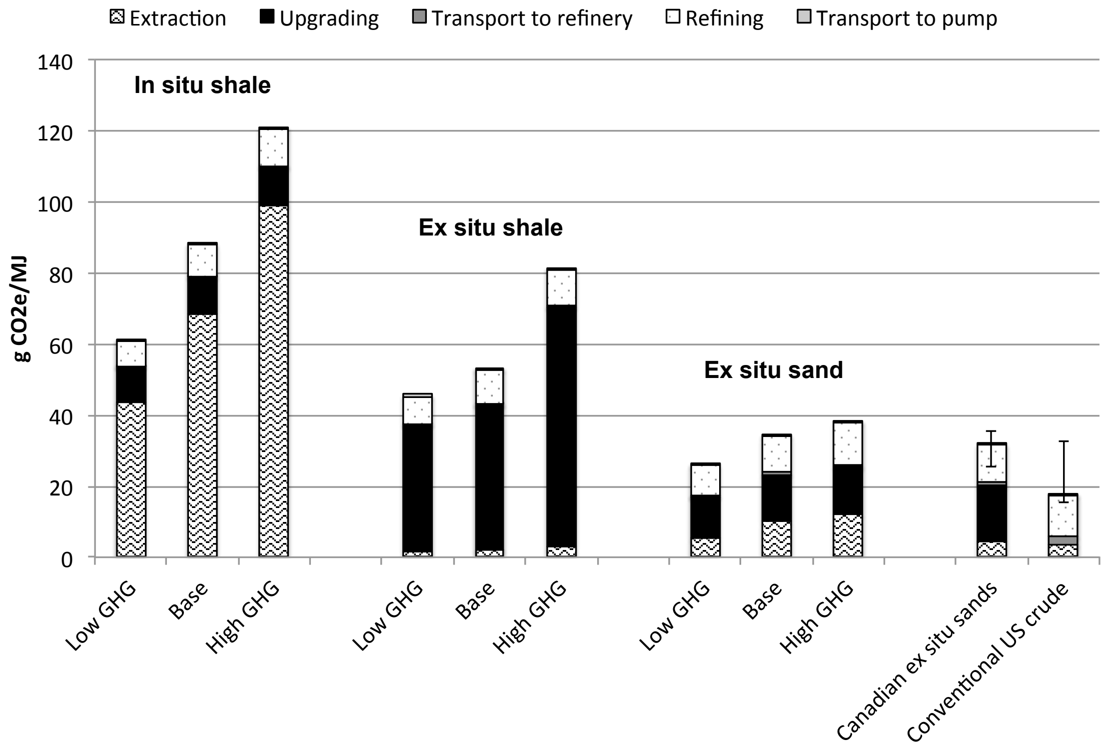

Figure 1. Comparison of WTP GHG emissions for production of conventional gasoline from in and ex situ production of Utah oil shale, ex situ Utah and Canadian oil sands (ANL, 2012), and conventional crude oil (EPA, 2009). The error bars on the Canadian ex situ sands show the range of values reported in McKellar et al. (2009) for reformulated gasoline[1], and the error bars for conventional US crude show the range of values reported in Gerdes and Skone (2009) for conventional gasoline.

The sensitivity analysis shows the importance of the resource quality (all scenarios), the retort process (ex situ shale), shale permeability (in situ shale), and project lifetime (in situ shale) on life-cycle GHG emissions. The range of WTP GHG emissions estimated for in situ (61.4 – 121 g CO_2 e/MJ) and ex situ (45.8 – 81.6 g CO_2 e/MJ) production of gasoline from oil shale is greater than the range of emissions for ex situ sand (26.4 – 38.5 g CO_2 e/MJ), Canadian oil sands or conventional crude. The variation between the low GHG and high GHG cases are greater for the oil shale scenarios than for the sand scenario because commercial processing of shale is not widely established and greater uncertainty is associated with the process selection and resource recovery.

Figure 2 presents the WTW life-cycle GHG emissions for the three scenarios (three sensitivity cases each) with oxyfiring and CO_2 capture along with the California LCFS and the Energy Independence and Security Act benchmark. The figure illustrates that it is possible to meet a LCFS through oxyfiring with carbon capture for the ex situ oil sands and shale scenarios.

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[1] Manufacture of reformulated gasoline generates approximately 4% more GHG emissions during the refining stage and approximately 1% in WTP emissions (ANL 2012), but insufficient information is available in McKellar (2009) to adjust their GHG emissions to a basis of conventional gasoline.

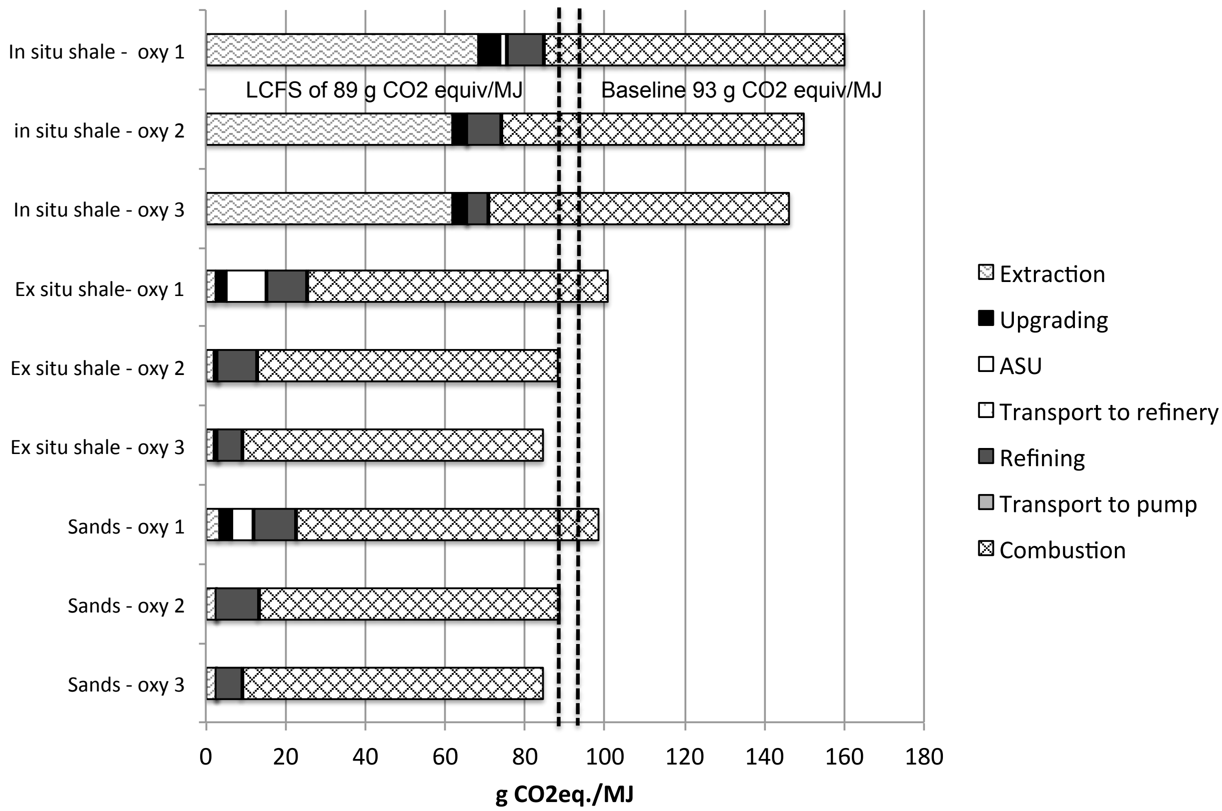


Figure 2. Comparison of estimated WTW GHG emissions for ex situ Utah oil sands and shale with the California LCFS of 89 g CO_2 e/MJ and the baseline GHG emissions associated with the Energy Independence and Security Act.

For the ex situ shale and sand cases, oxyfiring with CO_2 capture in the extraction and upgrading life-cycle stages can reduce WTW GHG emissions by 22–34% and 11–23%, respectively. A greater fraction of the ex situ shale CO_2 emissions are amenable to CO_2 capture. Because natural-gas generators used to heat the in situ shale cases are not suited to oxyfiring, WTW GHG emissions can only be reduced by 2–11%. Oxy case 1 GHG reductions are insufficient to bring any of the baseline WTW GHG emissions from these unconventional fuel sources to the baseline average GHG emissions of 93.3 g CO_2e/MJ (US EPA, 2009) or to the meet California's LCFS. Additional GHG reductions could be achieved by supplying all of the electricity from an oxyfired, natural gas combined cycle (NGCC) plant with CO_2 capture (oxy case 2). These additional steps would allow conventional gasoline produced from Utah oil shale and sand (baseline ex situ scenarios) to meet the California low-carbon fuel standard (LCFS). However, oxyfiring with CO_2 capture does reduce the net energy recovery (NER) slightly (Figure 3), and the cost of these fuels may not be economically competitive with other less GHG-intensive fuel sources. Fuels produced from in situ processing of oil shale are unlikely to meet an LCFS.

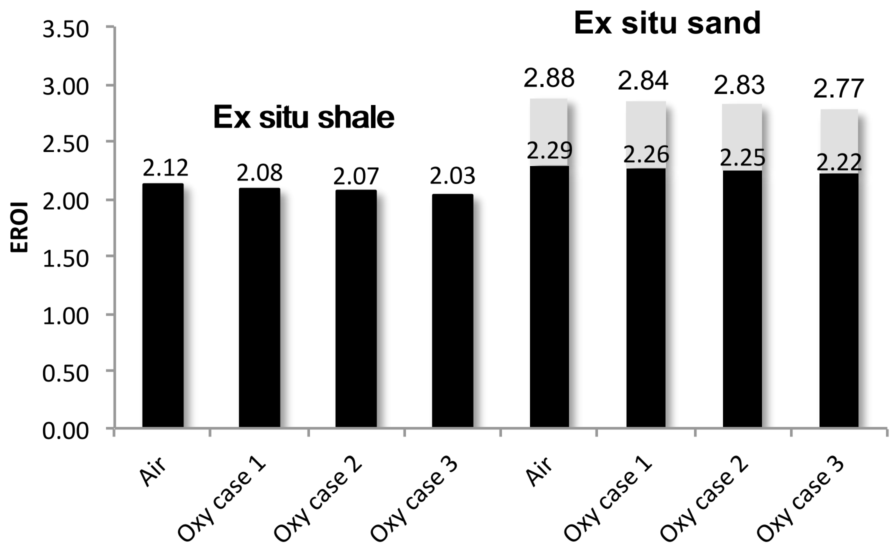


Figure 3. Point-of-consumption NER and net external energy return (NEER) estimates for the air-fired baseline and three oxyfired cases. For the shale cases, NER and NEER are equal, but for the sand cases NER (lower value) and NEER (higher value) are both presented. In situ sand is excluded because the baseline NER is less than one.

It is worthwhile to note that GHG emissions associated with air separation and CO_2 compression are less than the GHG emissions savings associated with the CO_2 capture. However, oxyfiring with carbon capture does reduce the NERs as shown in Figure 3. For the baseline ex situ oil shale case, applying oxyfiring with CO_2 capture decreases the NER by 1.9–4.4% for a corresponding reduction of 22–34% of WTW GHG emissions for oxy cases 1–3, respectively (52–83% for WTP GHG emissions). The application of oxyfiring with carbon capture and sequestration (CCS) to the baseline oil sands case decreases the NER by 1.2–3.6% with corresponding reductions in WTW GHG emissions of 11–23% for oxy cases 1–3, respectively (33–73% reduction in WTP GHG emissions). The ex situ shale scenario has a greater quantity of GHG emissions that are amenable to CO_2 capture than the sand scenario. Specifically, CO_2 emissions from the extraction and transport of the resource and overburden with diesel-powered equipment (assumed not capturable) are greater for the oil sands scenario than the ex situ shale scenario. Oxyfiring with CO_2 capture can also reduce in situ shale WTW GHG emissions by 2–11%. Because CO_2 from the generators that heat the shale formation, responsible for the majority of the WTP GHG emissions, are not capturable, oxyfiring with CO_2 capture has a smaller effect on the in situ shale scenario than on the other scenarios.

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

Work on the final deliverable for this task, a report detailing results of a validation/uncertainty quantification analysis, was on hold this quarter pending availability of the PI. The PI has finally been freed up with the completion of the Subtask 6.3 and a graduate student has agreed to help complete the work for this project.

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

During this quarter, the project team continued to build on their model for conventional oil development in the Uinta Basin. Specifically, their work has focused on (1) selecting a validation and uncertainty quantification (V/UQ) framework and (2) building a comprehensive set of constraints to oil development for use in the model. Given the results from recent work and the completion of other related work on unconventional oil development in the Basin, the research team would like to propose changes to the scope of this subtask and Subtask 3.4. This new scope will consider how the simultaneous development of conventional and unconventional oil resources might be constrained by having both industries draw from the same limited infrastructural, environmental, and bureaucratic resources in the Uinta Basin. Results from ICSE's recently completed market assessment of oil shale and oil sands resources (Subtask 6.3) will be incorporated with the results from the conventional oil development model to forecast the resource demands from growth of both industries. By comparing the predicted resource demands to what is available, the constraints to oil production in the Uinta Basin can be comprehensively identified. Specifically, researchers wish to change the remaining milestone and deliverable for Subtasks 3.3 and 3.4 to

- (Milestone) Demonstrate full functionality (integration of all modules) of the V/UQ methodology for conventional oil development in the Uinta Basin - Due date is November 2013
- (Milestone) Demonstrate full functionality (integration of all modules) for conventional and unconventional oil development in the Uinta Basin - Due date is March 2014
- (Deliverable) Topical Report describing models developed, V/UQ methodology applied to conventional oil model, lessons learned from its application to conventional and unconventional oil production in the Uinta Basin (synthesis of Subtasks 3.1, 3.3 & 3.4) - Due date is August 2014.

V/UQ Framework

Numerous V/UQ frameworks have been proposed for validating and verifying the results of computer simulations. Some of the frameworks in use are data collaboration (Frenklach et al., 2004), Bayesian analysis (Bayarri et al., 2005), probability bounds analysis (Roy and Oberkampf, 2011), ASME's Standard for Validation and Verification (ASME, 2009), real space validation (Romero, 2011), continuous Monte Carlo (Avramova and Ivanov, 2010), and polynomial chaos (Knio and Le Maître, 2006). Many of these frameworks are designed for systems where the function evaluation (e.g. simulation) is expensive and the experimental data are sparse, difficult to obtain, and highly uncertain. In contrast, the conventional oil process model constructed in this work is composed of algebraic equations which can be quickly computed, the dataset for conventional oil production available from the Utah Division of Oil, Gas and Mining (DOGM) is massive, and the uncertainty associated with the data is very small.

Of the existing V/UQ frameworks in the literature, data collaboration appears to be the best fit to this research problem. Data collaboration uses constrained optimization to perform a consistency analysis between a specified parameter space and a given dataset. A dataset unit is defined as a combination of a measured value, the reported uncertainty, and the mathematical model that describes the experiment. Parameters in the mathematical model can be varied simultaneously to determine the parameter space over which the model produces results consistent within the uncertainty bounds of the dataset's measured values.

After building in a more comprehensive set of constraints to the model (see constraints discussion below), the next step in the project will be to perform a consistency analysis using the data collaboration Matlab toolbox (DClabV2[2]). The historical observations from the DOGM database will have to be transformed into dataset units that contain both an observation and its uncertainty. The approach currently being considered is to pick a set of criteria for sorting all of the wells of interest into groups so that observations from any individual well in the group can

[2] Available online at: http://sourceforge.net/projects/collab-sci/

reasonably be assumed to be “repeat” observations of the same well. For example, if Company X drilled Y wells using identical techniques into the same reservoir, and if those wells were all operated identically and their production behavior wasn’t coupled, then the variance in the production histories of that set of wells could be treated as the experimental uncertainty in performing measurements of oil production from wells drilled under that set of conditions. Assuming that this or some other approximation is capable of determining the experimental uncertainty of conventional oil production, DClabV2 should be able to perform the desired consistency analysis.

Constraints on Oil Development

The two key elements of the conventional oil development model are (1) an economic component that forecasts the net present value (NPV) of a well drilled during a given time step and (2) a determination of how many wells can be drilled during the current time step based on the available constraints balance. The NPV of a given well is determined by comparing the projected revenue from that well using the most recent U.S. Energy Information Administration (EIA) oil price forecast[3] available during that time step and production volumes are estimated by integrating oil decline curves (fitted to DOGM well production data[4]) to the well’s costs (drilling capital costs are estimated from DOGM well logs, and well operating costs are taken from EIA data). The cash flow each year is adjusted for inflation and the result is summed together to give the NPV. If a well is predicted to be profitable (i.e. the NPV of the well is greater than zero), then the model sets the current number of wells that begin the drilling process (leasing, environmental assessment (EA) or environmental impact statement (EIS) analysis, application for a permit to drill (APD), drilling, completion, etc.) during that time step to the maximum number of wells that can begin the process based on the available constraint balance. Previous versions of the model only considered how much capital was available for investment in drilling, which led to an exponential growth in the number wells drilled, and subsequently, the amount of oil produced. This behavior was clearly unrealistic, so the project team began investigating specific constraints to oil development in the Basin.

A summary of the potential constraints under consideration for model inclusion is shown below in Table 2, followed by a short discussion of each constraint.

Table 2. Potential oil development constraints.

Constraint	Conventional Oil
Minimum Oil Price (2012 USD per bbl)	\$26 - \$53
Water Availability (acre-ft / yr)	
New water rights available for allocation	0
Produced water (in 2009)	20,000
Water rights held by State of Utah	
White River	100,500
Flaming Gorge	299,685
Water rights held by Water Conservancy Districts	55,905

[3] Available online at: http://www.eia.gov/forecasts/aeo/

[4] Available online at: http://oilgas.ogm.utah.gov/Data_Center/DataCenter.cfm

Constraint	Conventional Oil
Air quality	
State of Utah permits / requirements	None, SIP if nonattainment for ozone
EPA	
Tribal minor source	Up to 90 days for permitting decision
NESHAP	Rulemaking in progress
Green completions	Only for gas wells
BLM	Influences EA or EIS decision
Regulatory Approval	
Leasing (months)	10
APD (days)	30 - 298
NEPA analysis for federal lands (yr)	1.5+
Transportation Capacity	
Truck (BPD)	206,700 – 565,000
Oil pipeline (BPD)	19,400
Gas pipeline (billion standard cubic feet per day)	1.26
Other	
Refinery capacity (BPD)	175,000 – 215,000
Electricity – Western Interconnection (MW)	
Net internal demand, 2011	117,755
Capacity, 2011	147,147
Drilling Rigs	8 – 49

The first hurdle (and only hurdle in the absence of technical and political constraints), is that the method for producing oil must be economical. Recent studies (HDR, 2013) have estimated that the marginal cost of production for conventional oil from the Uinta Basin is between $26–$53 per barrel. Given recent EIA forecasts which predict average oil price of $135 per bbl (US EIA, 2012), it's highly unlikely that economics will be a constraint for conventional oil production for the foreseeable future.

Another clear constraint for any industrial development in the Uinta Basin, including oil production, is water availability. Conventional oil production only requires water during drilling, fracking, and completion of the oil well, with total water demand on the order of 0.5–5.0 million gallons of water per well, depending on the site specific details of each well (Holsinger and Lemke, 2012). Based on a preliminary analysis showing that an oil well in the Basin produces approximately 47,300 barrels of oil in its lifetime, each well consumes approximately 0.3–2.5 bbl of water per barrel of oil produced. Between 10%–40% of this water flows back out of the well as produced water, which must then be either disposed of or reused (Holsinger and Lemke, 2012).

The largest and most promising water rights for oil development are water rights held by the State of Utah on the White River (100,500 acre-feet per year or acre-ft/yr) (Utah Division of Water Rights, 2013), which is equivalent to 100% of the White River's flow rate during low flow periods. Other potential sources of water are the Duchesne County and Uinta Water Conservancy Districts, which hold sizable (99,400 acre-ft/yr diversion or 55,905 acre-ft/yr depletion) water rights as a result of the Flaming Gorge Water Right Apportionment (Utah Division of Water Resources, 1999). Another smaller but still significant source of water is reuse of produced water. If treated to remove solids and other contaminants, produced water could be reused for drilling or for unconventional oil processes at lower cost than the acquisition of existing water rights. In 2009, oil and gas wells produced approximately 20,000 acre-ft of water (Keiter *et al*., 2011). Finally, it should be noted that given the variability in water supplies, some form of large storage capacity (reservoir, aquifer, etc.) will have to be developed to ensure continuity of supply, especially for unconventional oil processes which require constant water input.

Air quality could be another major constraint for oil development. Emissions from oil and gas wells are not currently regulated by the State because wells typically qualify for a small source exemption[5]. Collectively, however, winter-time ozone formation caused by emissions of volatile organic carbons (VOC) and nitrogen oxides (NO_x) from oil and gas equipment is expected to lead to the Basin being classified as nonattainment for ozone within the next three years (Utah DEQ, 2013). If the Basin receives a nonattainment designation, a State Implementation Plan (SIP) will be required, which would take another three years to produce. A number of other air quality regulations could constrain oil development in the Basin, including:

- Minor source permitting on Indian Country, where the EPA has regulatory authority (US EPA, 2013)
- New source performance standards under EPA's National Emission Standards for Hazardous Air Pollutants.
- "Green completions," a set of work practices and equipment intended to minimize emissions from drilling equipment and fluids, are being required by EPA on all hydraulically fractured gas wells (US EPA, 2012).
- Air quality is a consideration in EA and EIS analysis required under the National Environmental Protection Act (NEPA).

From the perspective of industry, regulatory approval in general acts as a constraint to oil development. Exact regulatory approval steps depend on land ownership. The first step in acquiring mineral rights from the land owner, typically in the form of a lease. Leases are sold at auction by the State of Utah School and Institutional Trust Lands Administration (SITLA) for state lands and BLM for federal lands. With mineral rights in hand, a developer must next apply for an APD. All wells drilled in the State of Utah (private, state, Indian, or federal) must be granted an APD by DOGM. One complicating factor in determining how long approval takes for a given well is that a single APD may cover an entire drilling project with hundreds of wells. On Indian and federal lands, where BLM has regulatory authority, an additional BLM APD is required. However, before BLM can issue an APD, a NEPA analysis (either EA or EIS) must be completed. A timeline of the entire industry approval process is shown below in Figure 4.

[5] R307-401-9 Small Source Exemption, http://www.rules.utah.gov/publicat/code/r307/r307-401.htm#T9

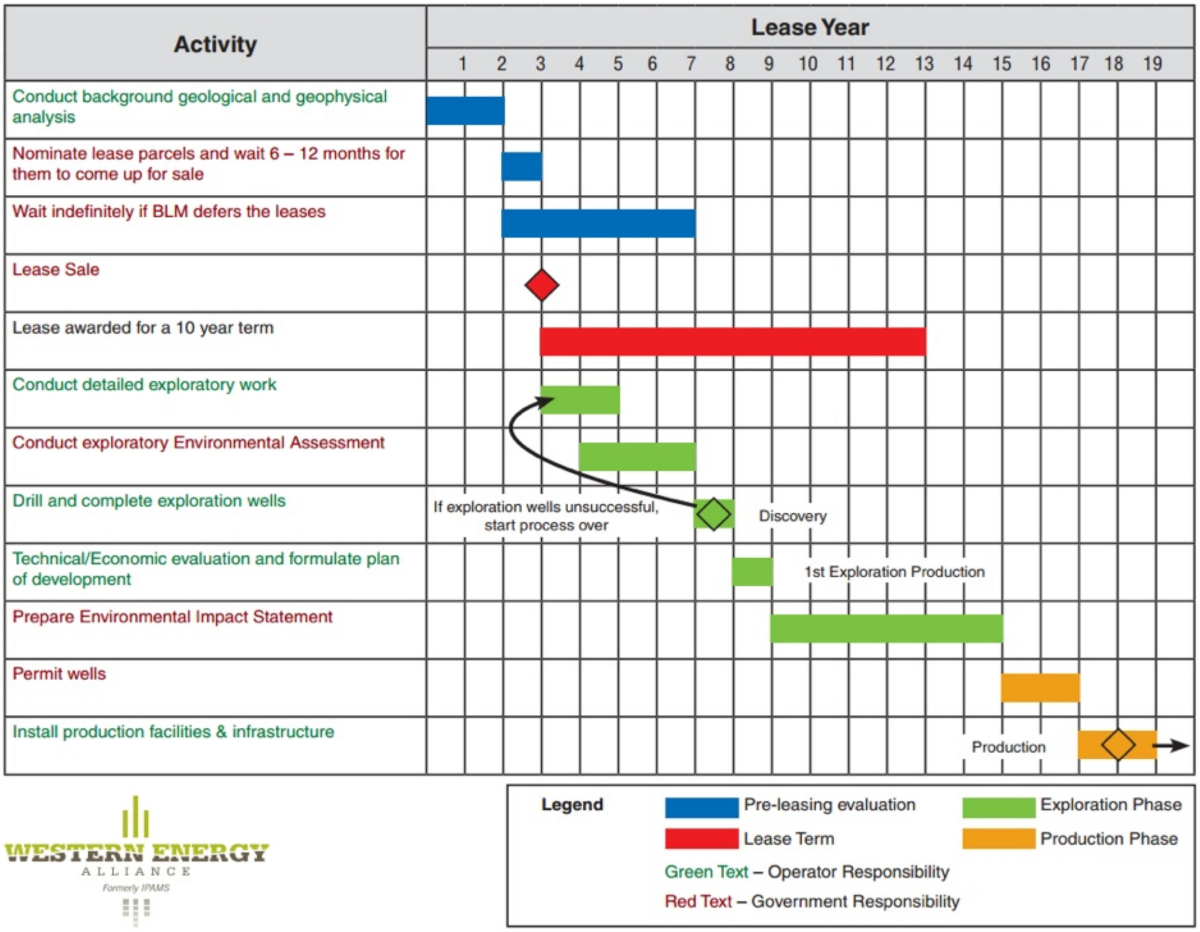


Figure 4. Federal onshore oil and gas process time line; from Western Energy Alliance (2012).

Transportation capacity into and out of the Uinta Basin was recently investigated as a potential constraint on oil development (HDR, 2013). The study quantified existing and planned transportation capacity in the Basin by truck and pipeline, finding that the total capacity for oil transportation out of the Basin to North Salt Lake was between 226,000–584,000 BPD with predicted potential development exceeding transportation capacity by 2020.

Other constraints that have been identified as potentially limiting development of oil resources in the Basin include: public safety, electrical power distribution and capacity, wildlife, availability and cost of labor and materials, and refinery capacity. Some of these constraints can be easily investigated. Refinery capacity in the region is well known (175,000 BPD existing, with planned expansions of 40,000 BPD) (HDR, 2013). Electrical power capacity is tracked by the EIA. The Western Interconnection, which includes the State of Utah, had a total demand of 117,755 MW and capacity of 147,147 MW during the summer of 2011 (US EIA, 2013). Historical rig counts are closely tracked for conventional oil production (Baker Hughes, 2013), but labor and materials in the oil industry can travel to follow demand.

The constraints listed in Table 2 can be incorporated into the conventional oil production model in a number of ways. Process economics is built into the model as the primary constraint by the NPV check. Water rights held by the State of Utah and/or the Water Conservancy Districts serve as an upper limit on water availability. Time delays and compliance costs can be included for regulatory processes (air quality, leasing, NEPA analyses, APDs, etc.). While these constraints are not hard limits on development, delaying positive cash flows in NPV calculations and adding extra upfront expenses reduces profitability overall, and thus acts on the model's economic constraint. Hard limits include transportation, refinery, and electrical grid capacity as well as drilling rig counts.

Subtask 3.4 - V/UQ Analysis of Basin Scale $CLEAR_{uff}$ Assessment Tool (PI: Jennifer Spinti)

The Subtask 3.3 includes a summary of activities associated with V/UQ analysis as the work for these two subtasks has been combined due to staffing issues. The Subtask 3.3 summary also includes a revised schedule for the remaining milestones and deliverable.

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

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

In this quarter, the research team continued to develop their high performance computing (HPC) simulation tool to simulate thermal heating of shale. They modified the generalized, rubblized shale bed geometry introduced previously by removing the pipe heating element and replacing it with a planar heating element. They also successfully addressed meshing difficulties encountered previously to create a mesh that captures heat transfer not only through the pieces of shale, but also through the convective channels which are formed between the rubblized pieces of shale. Researchers started to run this simulation, but because of the fine mesh, the simulation has not yet been completed.

In the report for the January-March 2013 quarter, a rubblized shale bed geometry with three different pipe positions was introduced. Because of meshing difficulties associated with those geometries, the research team removed the heating pipe from the geometry. The new geometry is shown in Figure 5. As previously, the rubblized shale bed interior is 1m x 1m x 1m in size. This $1m^3$ rubblized shale is surrounded by 0.5 meters of solid shale on each side to form a 2m x 2m x 2m simulation domain. The bottom plane of the simulation is assumed to be a planar heating source with a constant temperature of 700 K.

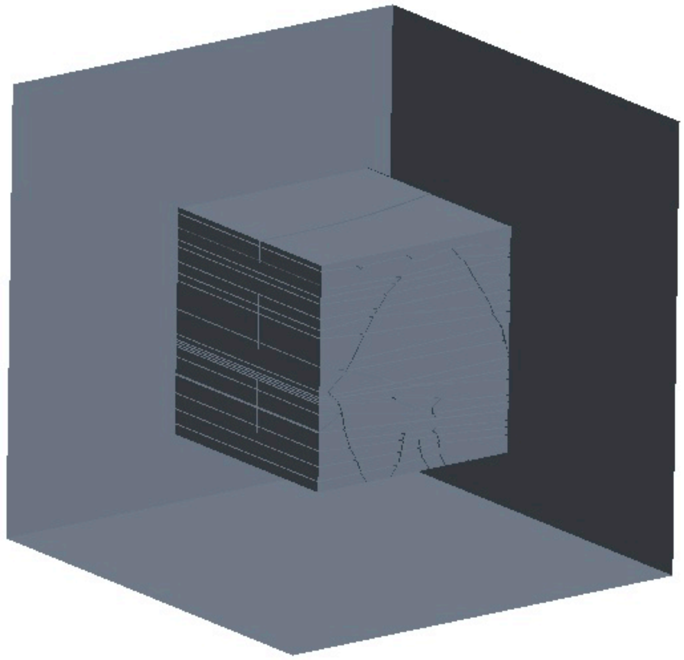


Figure 5. Modified simulation geometry used to study the effect of rubblization on the overall heat transfer inside the generalized shale formation.

With these geometry modifications, researchers were able to successfully mesh the geometry. Figures 6 through 9 show details of the mesh. As can be seen, the mesh is coarser in the solid piece of shale with decreasing sizes to represent the rubblized shale pieces. The smallest cell sizes represent the fluid void between the pieces of shale. In total, the mesh has 110 million cells.

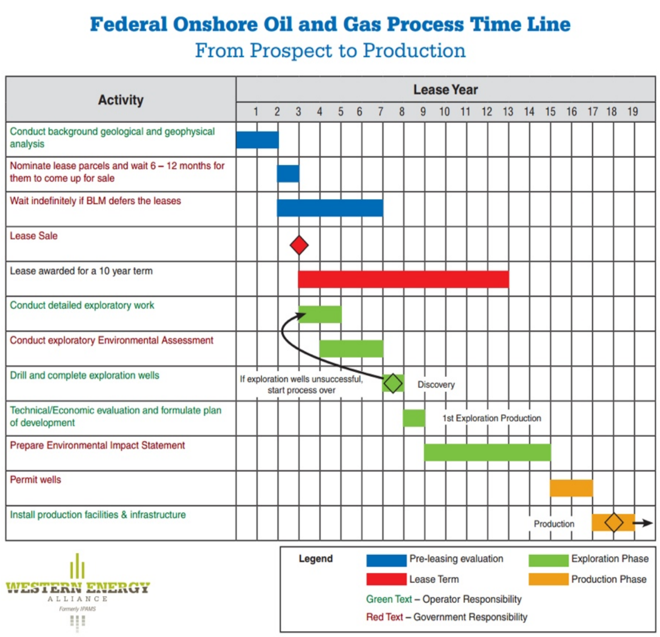


Figure 6. Mesh used to resolve individual pieces of shale.

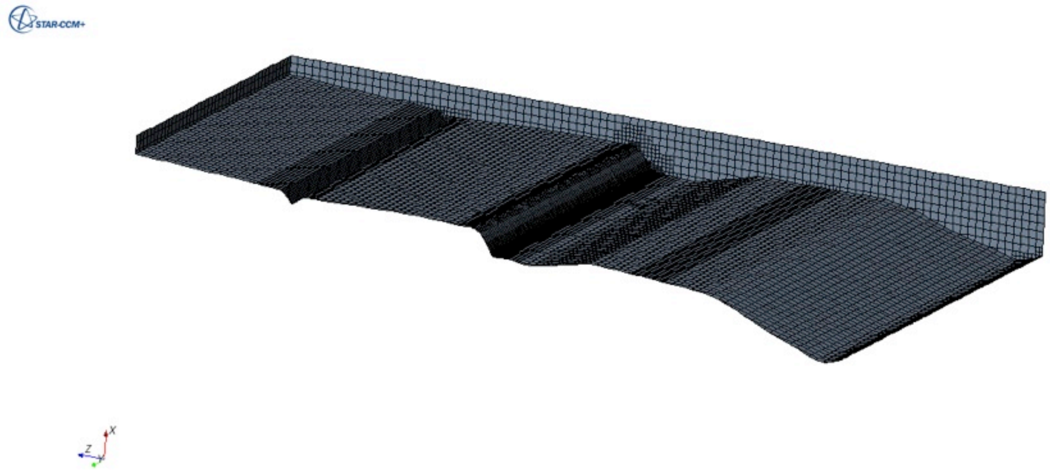


Figure 7. Close-up of the mesh for one piece of shale.

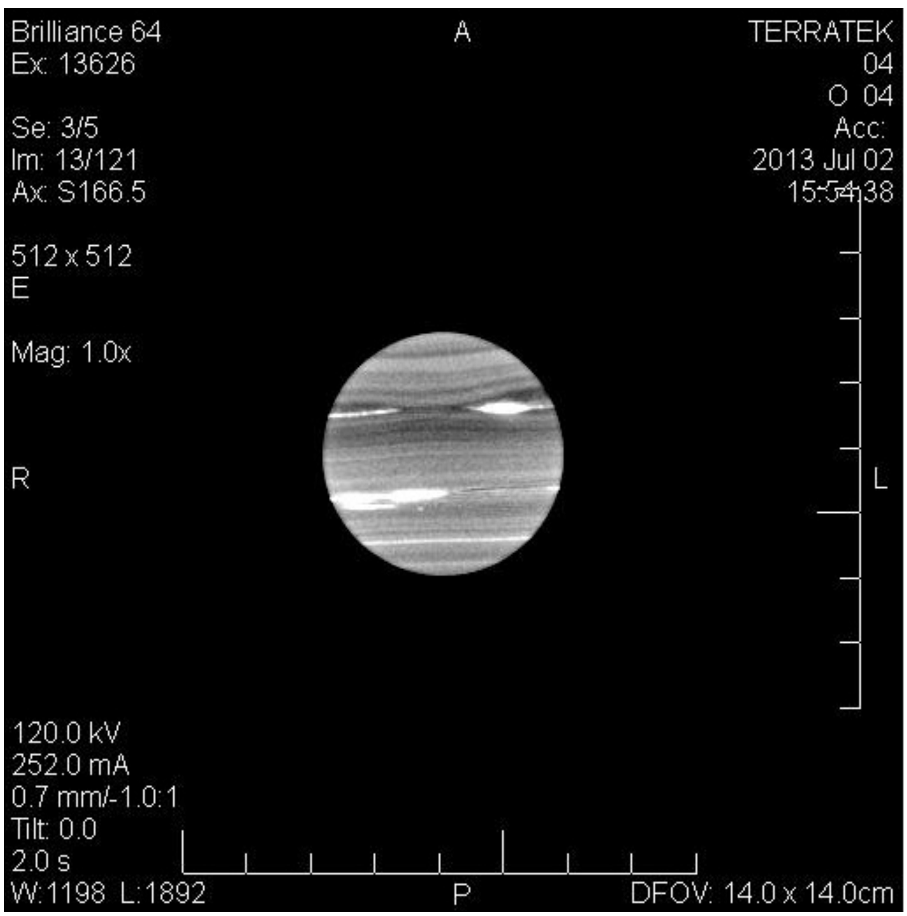


Figure 8. Cross-sectional plane showing cell size distribution throughout the simulation domain. The outer, large cells are used to represent the solid block of shale, whereas a finer mesh is used to resolve the individual pieces of shale and fluid occurring between the pieces of shale.

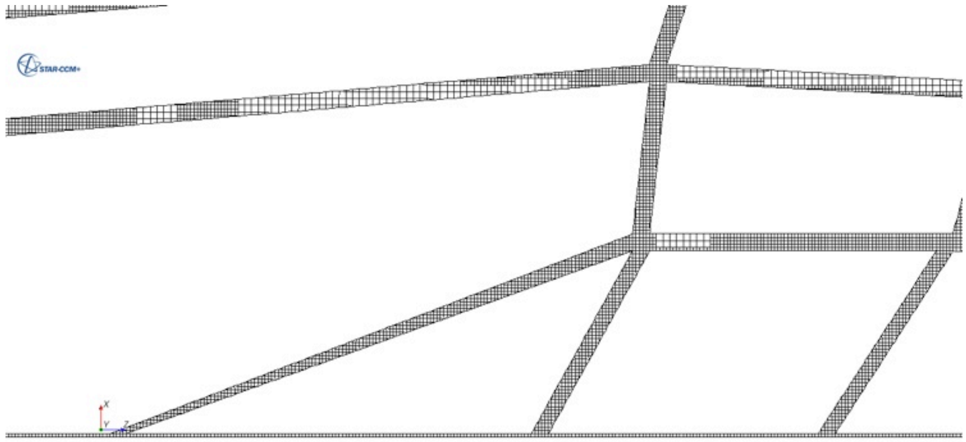


Figure 9. Close-up of the very fine mesh used to capture the fluid movement inside the convective channels which occur between the pieces of shale (solid white color in this figure).

To capture, analyze, and compare the heat transfer rates for both solid and rubblized pieces of shale, researchers have created a plane of 100 by 100 points at which temperature as a function of time is captured. In effect, these points. seen in Figure 10, represent probes that are dispersed throughout the simulation domain. With this data, the effective thermal conductivity as a function of void space can be computed for the simulation.This simulation is currently being run with the operator splitting algorithm. However, because of the large mesh needed to resolve the very fine geometric detail, this simulation is still in progress.

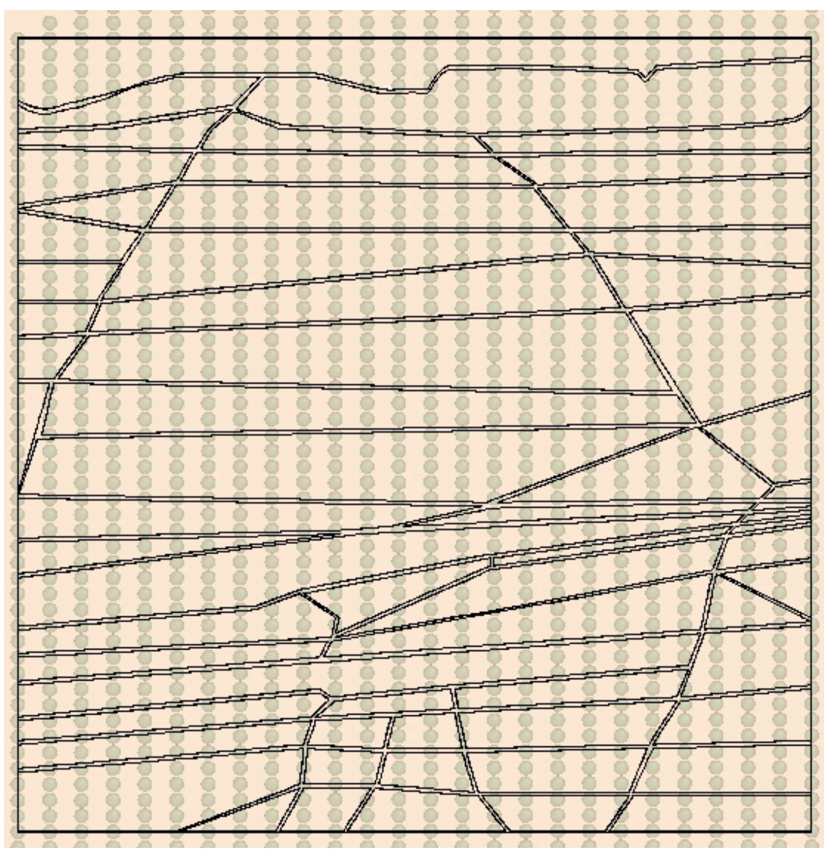


Figure 10. Temperature probes inside the simulation domain.

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

The project team continued its validation activity of comparing experimental core pyrolysis results with models in this quarter. Previous validation efforts using the COMSOL multi-physics model showed results that were not in good agreement with the experimental results (see Figure 11 but note that the sample sizes and surface temperatures used were not the same between simulation and experiment). While it took more than 200 minutes to heat up the sample experimentally, the center temperature was reached in less than 100 minutes in the simulation. This mismatch is due to the fact that it has not been possible to create a realistic heat loss profile in COMSOL.

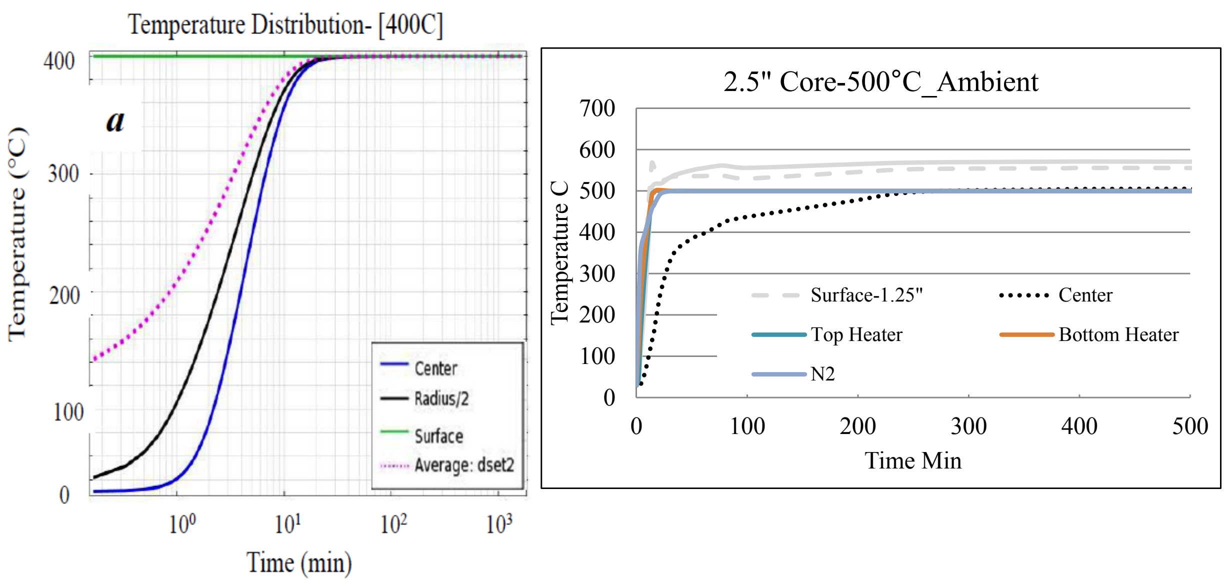


Figure 11. (left) Temperature distribution at various locations in sample from multi-physics COMSOL simulation of 10 cm diameter sample with a surface temperature of 400°C. (right) Temperature distribution from core experiment performed with a 6.35 cm diameter sample and a surface temperature of 500°C.

In this quarter, project team members have recreated a model in COMSOL for comparison and validation with the core-scale experiments to see whether the predictions can be improved. Results of this effort, some of which are shown in Figure 12 through 15, will be summarized in an upcoming topical report.

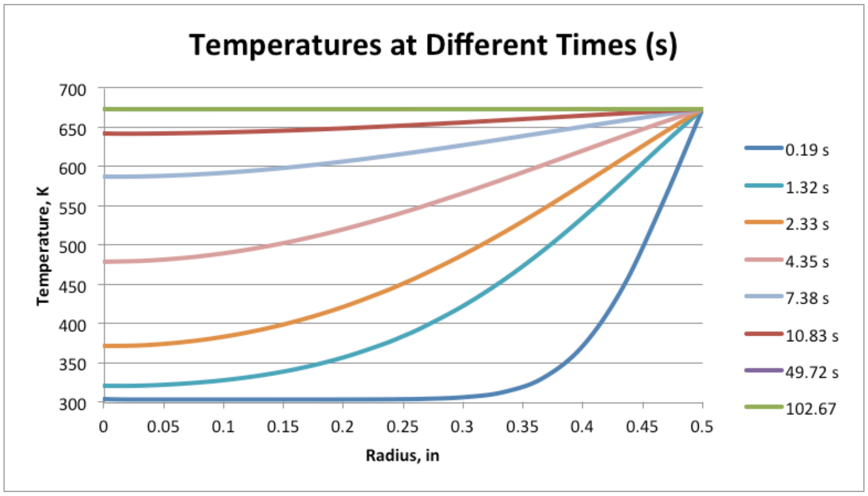


Figure 12. Temperature gradient of a core with a 2.54 cm diameter at various times.

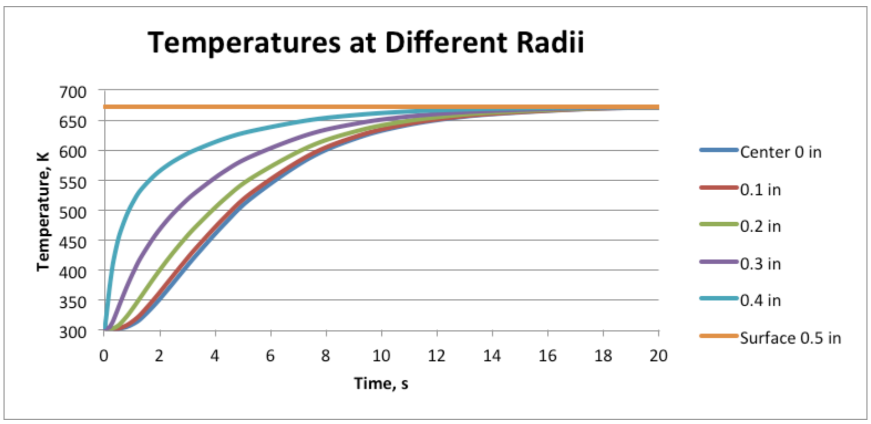


Figure 13. Temperature gradient of a core with a 2.54 cm diameter at various radii.

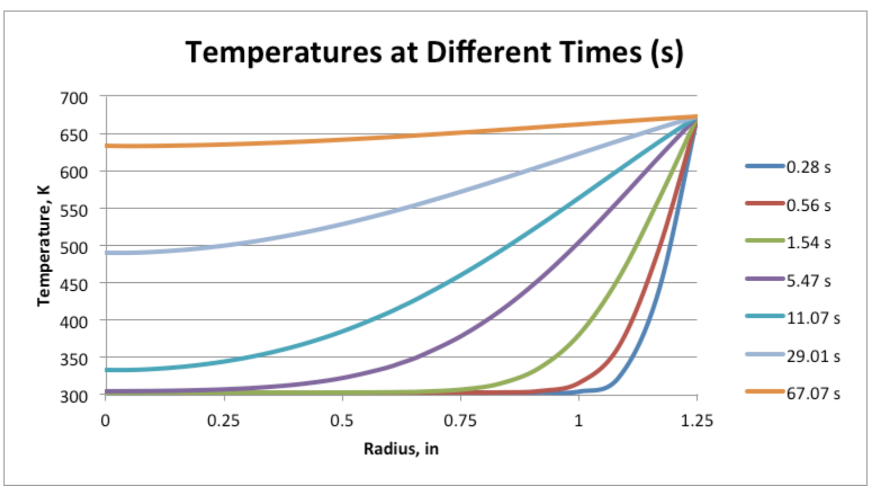


Figure 14. Temperature gradient of a core with a 6.35 cm diameter at various times.

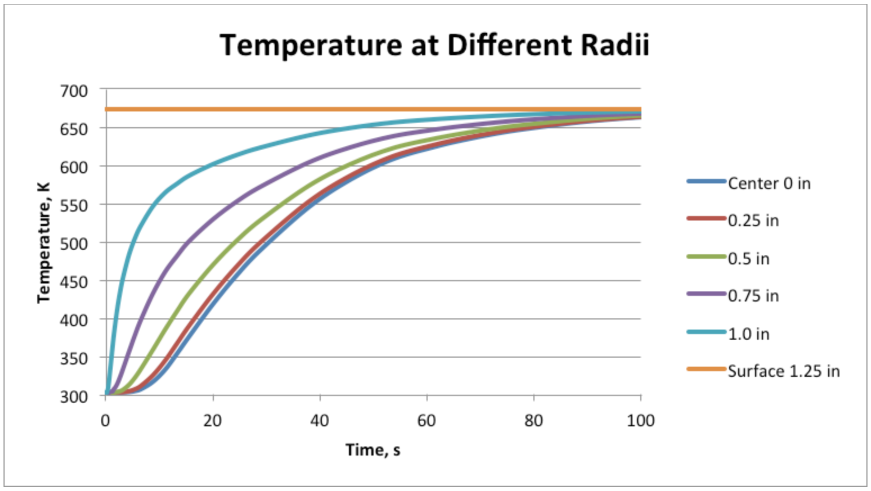


Figure 15. Temperature gradient of a core with a 6.35 cm diameter at various radii.

<u>Subtask 4.3 – Multiscale Thermal Processes (PI: Milind Deo, Eric Eddings)</u>

There are two deliverables left for this project:

- Topical report describing CPD/shale & oil generation (pyrolysis) models including summary of their applications/limitations (due date changed to August 2013)
- Paper on combined kerogen/bitumen structures & CPD reaction model submitted to a journal such as Energy & Fuel (joint deliverable with Subtask 4.9) (due date changed to August 2013)

Comparison of Oil Shale Pyrolysis Models

A comparison of the rates of pyrolysis at different heating rates reported by Dr. Fletcher's group at Brigham Young University (BYU) and Dr. Deo's group at the University of Utah (UU) has been performed by Drew Gillespie at BYU. This comparison included the following steps:

1. Reproducing the first-order model with variable activation energy reported by Twari and Deo (2013).
2. Digitizing the data from that paper.
3. Comparing the first-order and distributed activation energy models from BYU vs. the UU data at 1, 5 and 10 K/min.
4. Comparing the first-order and distributed activation energy models from BYU vs. the BYU data at 1, 5, and 10 K/min.
5. Comparing the UU first-order model with variable activation energy vs. the BYU data at 1, 5 and 10 K/min.
6. Plotting the 1 K/min data from BYU and UU on the same plot. Preparing siimilar plots for 5 K/min and 10 K/min.

This comparison has been completed (see Figure 16), and the project team is currently trying to resolve differences. Of particular note, the 1 K/min data do not compare very well. There is about a 25 K difference between the two data sets in the temperatures at which the pyrolysis occurs. This has important implications when extrapolating models to lower heating rates.

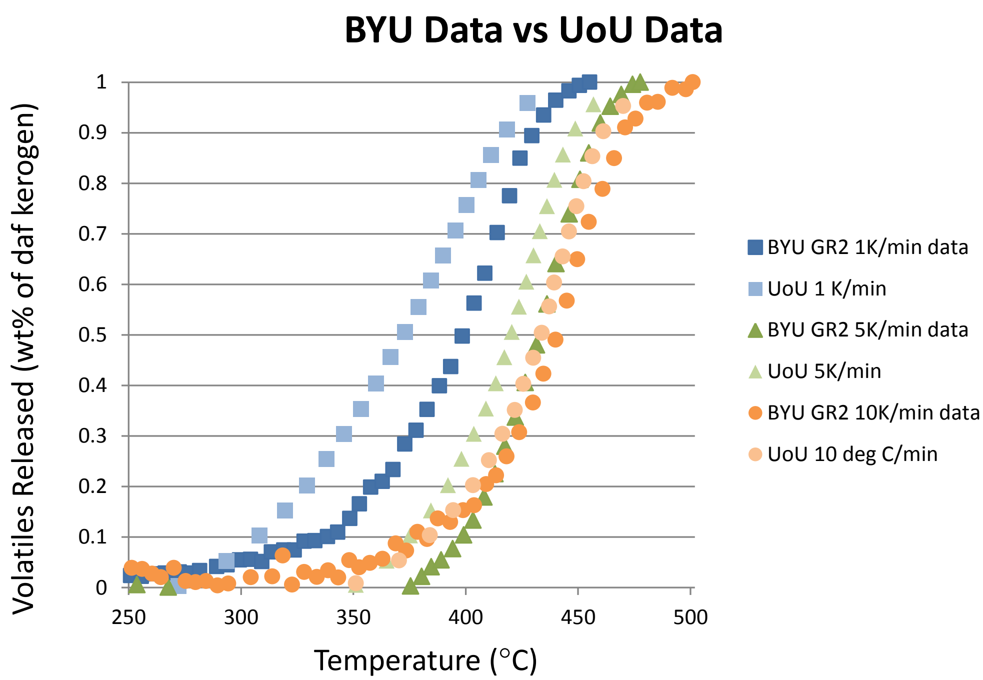


Figure 16. Comparison of BYU vs. UU pyrolysis data from the GR2 sample at atmospheric pressure and heating rates of 1, 5, and 10 K/min.

Chemical Percolation Devolatilization (CPD) Model

Additional research on the application of the CPD model to oil shale pyrolysis has beeen performed. A cluster size of approximately 750 has been obtained by the NMR experiments. This is much larger than for coal and is largely aliphatic with side chains of 10 to 14 carbons. Vapor pressures were computed for decane ($C_{10}H_{22}$), dodecane ($C_{12}H_{26}$), and tetradecane ($C_{14}H_{30}$), with coefficients from the Design Institute for Physical Properties (DIPPR), located at BYU and sponsored by the American Institute of Chemical Engineers. Computed vapor pressures as a function of temperature were compared with the correlation for coal tars developed for the CPD model, as shown in Figure 17. Also, new coefficients for the correlation used in the CPD model were regressed, which uses the following form:

$$P^* = A\exp\left(\frac{-BMW^C}{T}\right) \quad (1)$$

where P^* is the vapor pressure of a compound with molecular weight *MW*. The new correlation is much better than the CPD correlation for coal tar, but it is still in need of improvement. As the molelcules thermally decompose, some of the alkane material is still attached to the aromatic ring. Data for long chain alkanes connected to aromatic ring clusters might also be useful. It must be noted that the temperatures where the vapor pressures rise above 1 atm for the three n-alkanes in Figure 17 are in the range 450 to 550 K (177 to 277°C), while the temperature range for pyrolysis at 1 K/min is 350 to 400°C based on the data from BYU and UU.

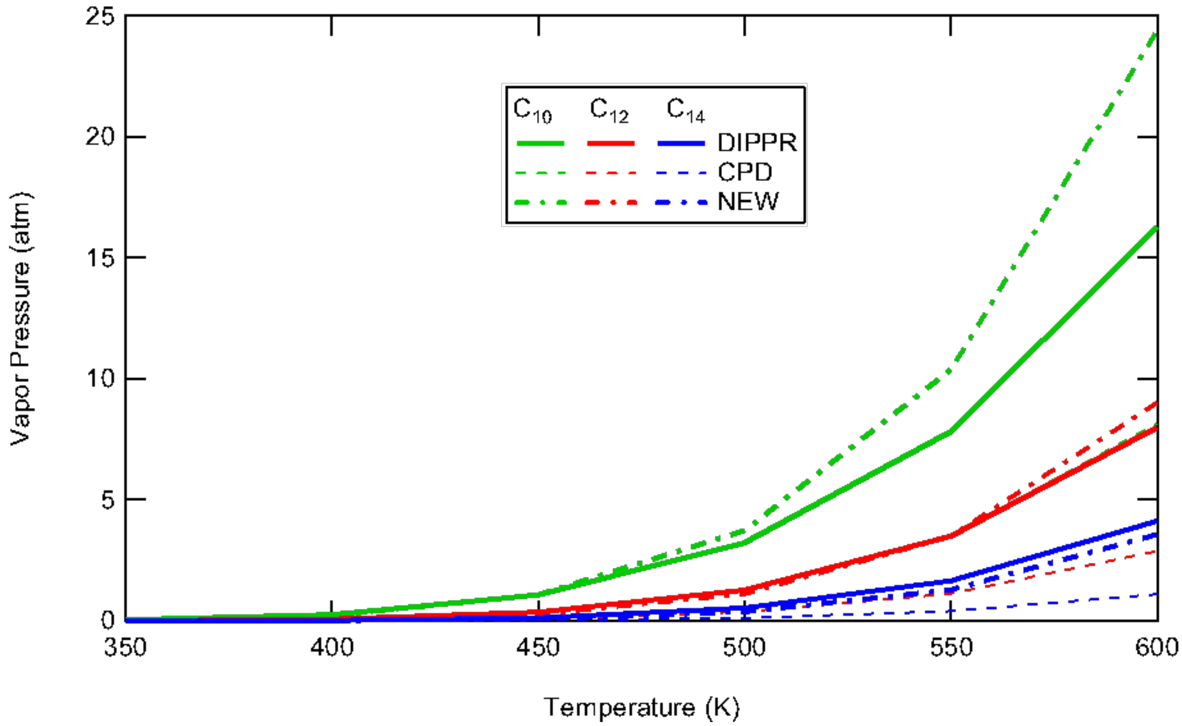


Figure 17. Vapor pressures computed for *n*-decane, *n*-docecane, and *n*-tetradecane as a function of temperature. Also shown are vapor pressures computed from the CPD correlation for coal tar vapor pressures and the new correlation for *n*-alkanes.

Journal Papers

The project team is in the process of drafting and completing two papers.

- A paper on the Nulcear Magnetic Resonance (NMR) analyses of the three oil shale samples studied by Subtask 4 research teams (GR1-3), as well as the bitumen extracted and the demineralized kerogen. This paper is approximately 50% complete. It will be submitted to *Energy & Fuels*.
- A paper on the analysis of the pyrolysis products from kerogen, including NMR analyses of the char and tar samples obtained at different temperatures, GC/MS analyses of the tar samples, and FTIR analysis of the light gases. This paper is approximately 90% complete. It will be submitted to *Energy & Fuels*.

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 two outstanding milestones: (1) complete experimental matrix, due December 2012 and (2) complete thermophysical and geomechanical property data analysis and validation, due March 2013. The research team will be performing tests on Skyline 16 samples in the next quarter. These tests will allow the compilation of information to complete the two milestones.

- Complete experimental matrix – Researchers will test samples provided by AMSO in addition to the Skyline 16 samples.
- Complete the thermophysical and geomechanical property data analysis and validation – This milestone will be accomplished with the data collected from the experimental matrix. Researchers also plan on running low temperature validation tests on independent (commercial) triaxial testing equipment.

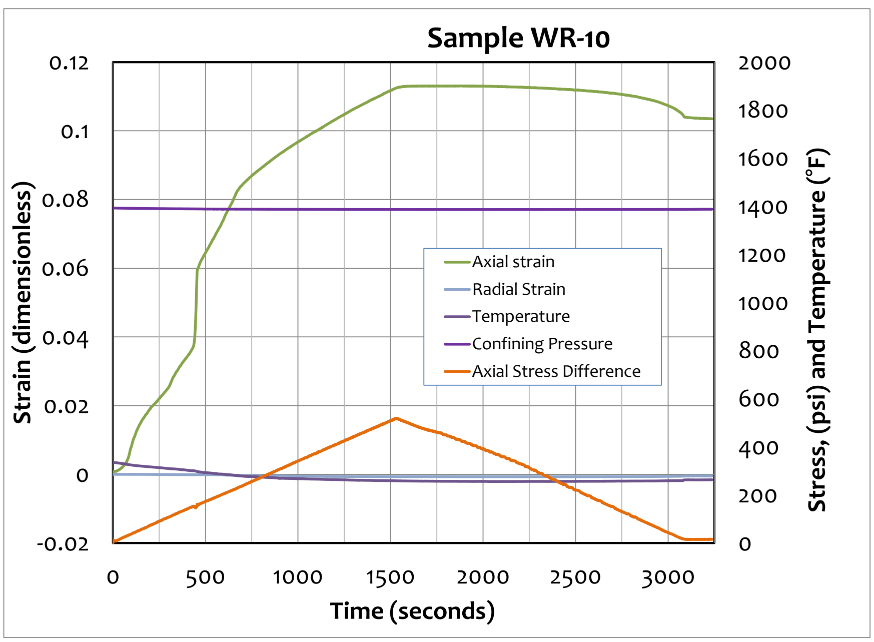
A new clamshell heater with customized design (allowing the measurement of the sample's radial strain) was implemented. Four LVDTs with arms are fed through four holes on the new heater and make contact with the sample. The bodies of the LVDTs are outside of the heater and mounted in a new fixture; see Figure 18. Now samples can be tested at pyrolysis temperatures and deformation can be measured in three orthogonal directions.

Figure 18. Clamshell heater with radial and axial cantilevers mounted. For scale, the heater is about 12 inches in height.

In the apparatus, membranes prevent the fluid that provides the hydrostatic confining pressure in the vessel (nitrogen) from penetrating into the sample itself. However, conventional membranes (e.g., Teflon, polyurethane) cannot tolerate high temperature testing (400°C). Up to this point, very thin-walled (0.008 in) copper jackets (e.g. membranes) had been machined from a copper tube. While this has been the classic method for high temperature testing, the copper jacket was too stiff. When the samples failed, the jacket itself was providing reinforcement. While the data collected at high temperature are unique and valuable, it is desirable to minimize the lateral restraint provided by the jacket. The research team is presently evaluating a 0.002-in thick copper foil with high temperature sealant. This membrane should afford easier radial deformation of the axially loaded sample.

While testing oil shale samples from the White River mine, other experimental difficulties were encountered. One was the uneven surface of the high pressure vessel. The inside surfaces of the top and bottom lids of the vessel have some variation from “flat and parallel.” The sample tended to tilt in one direction instead of deforming evenly with the three axial LVDTs. This difficulty is being resolved. Another difficulty is when the sample is stiff (does not deform substantially), usually at ambient temperature. Researchers tried different spherical seats to prevent these problems, but they did not work well. At high temperature (200°C to 400°C), the loading fixtures seat adequately and the deformation is reliably measured.

Figure 19 shows the stress-strain-time data for a White River sample. Researchers continue to work on methodologies for maintaining constant temperature and will next infill the annular space between the heater and the sample with small metal spheres. The temperature shown in Figure 19 is measured in the annular gap (nitrogen only in the case shown). The sample temperature is nominally constant through the test even though there is variation in the annular space outside of the sample. The low radial strain (Figure 19, bottom) to a certain extent is expected with conversion of the kerogen. However, its occurrence in conjunction with the stiffening of the axial stress-axial strain curve, has led to re-evaluation of the copper jacket.



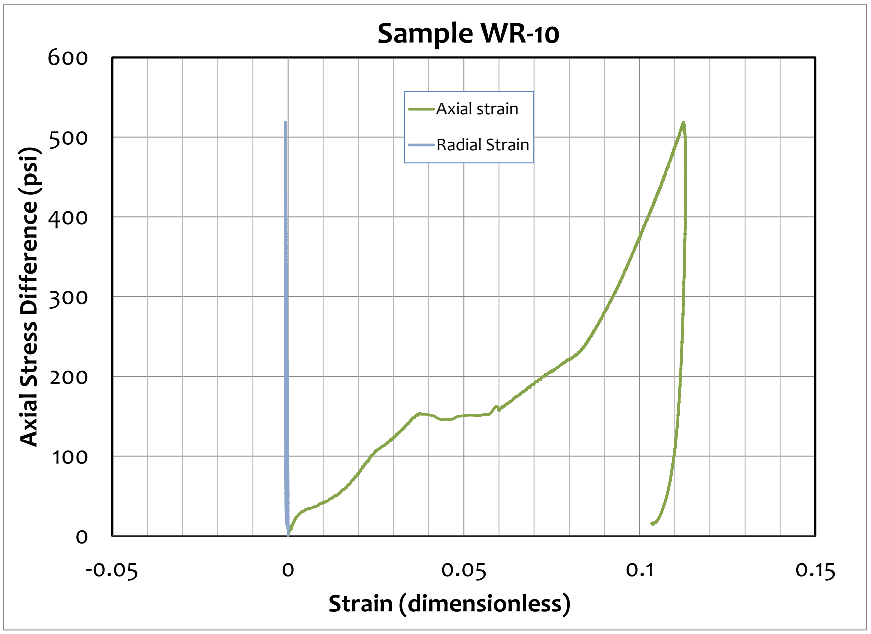


Figure 19. (top) Snapshot of stress, strain and temperature during a portion of a test on a White River sample. The confining pressure (1400 psi) is also shown. (bottom) Axial stress difference versus axial and radial strain.

Skyline 16 oil shale plug samples have undergone computed tomography (CT) scanning in advance of testing. Figure 20 is an example. Upcoming tests on Skyline and White River oil shale samples will be triaxial and will add confining pressure and higher temperatures.

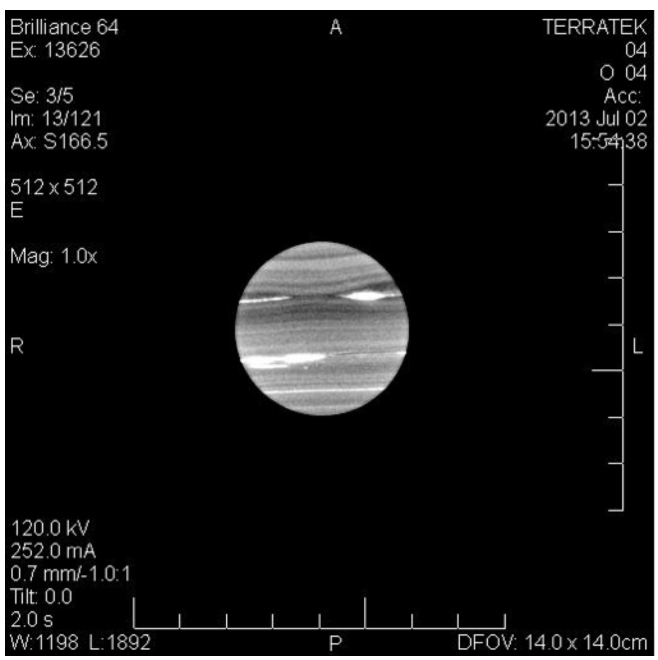


Figure 20. One of multiple (every mm) cross-sectional CT scans of a Skyline oil shale plug (1-inch diameter).

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

Subtask 4.8 research team efforts were focused on finalizing E-W and N-S core- and log-based cross sections of the Green River Formation throughout the Uinta Basin. The cross sections highlight key stratigraphic correlation of oil shale rich and lean zones, lateral and stratigraphic lithologic changes across the basin, as well as lake basin evolution.

Finalized individual core logs along with associated geochemical data are being updated in preparation for upload to the ICSE data repository, which is the final project deliverable. The upload will be completed by August 15, 2013, and is currently being coordinated with ICSE. The list of items for upload include:

1) Plate 1. West-east core-based cross section through the middle to upper Green River Formation, Uinta Basin, Utah. This plate includes a map.
2) Plate 2. North-south core-based cross section through the middle to upper Green River Formation, Uinta Basin, Utah. This plate includes a map.
3) Plates 3–10. Individual core logs from Asphalt Wash 1, Coyote Wash 1, EX 1, P4, Red Wash 1, Skyline 16, South Uinta Basin 12, Utah State 1, respectively.
4) Appendix. All X-ray fluorescence (XRF) data from all nine cores with data in XLS format.
5) Plots of XRF data, in pdf format, organized by well.
6) Quantitative Evaluation of Minerals by SCANning electron microscopy (QEMSCAN) analysis results in pdf format.

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

The project team is still completing work on the final deliverable, a paper on combined kerogen/bitumen structures and the CPD reaction model. The paper has been tentatively titled "Characterization of Shale, Kerogen and Bitumen from a Green River Oil Shale Core."

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)

Efforts this quarter focused on augmenting the research presented in last quarter's white paper describing existing judicial and agency approaches for estimating error in simulation methodologies used in context of environmental risk assessment and impacts analysis. Additional work began on organization and preliminary drafting of the topical report.

6.0 – Economic and Policy Assessment of Domestic Unconventional Fuels Industry

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

The milestone to upload all process models used and data collected to the ICSE website will be completed on August 15, 2013. This milestone has been delayed due to a change in personnel managing the website. The final deliverable, a summary of models used and parameters analyzed for the microeconomic assessment of oil shale and oil sands development, was completed with the publication of the Market Assessment Report (Subtask 6.3) on July 5, 2013.

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

The topical report is being finalized and will be submitted on August 10, 2013.

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

The final deliverable, a report entitled "A Market Assessment of Oil Shale and Oil Sands Development Scenarios in Utah's Uinta Basin," was completed in this quarter. The official report release date was July 5, 2013. It is available for download at http://www.icse.utah.edu/leftnavid3subleftnavid10subpage115. The report is also available on a flash drive by sending email to jennifer.spinti@utah.edu.

7.0 – Strategic Alliance Reserve

Subtask 7.1 – Geomechanical Model (PI: John McLennan)

There is one overdue milestone for this subtask, to infer permeability-porosity-temperature relationships and to develop model that can be used by other subtasks (due December 2012). The research team continued to work on "Version 1" of the geomechanical model in this quarter. However, completion of this milestone has been delayed as researchers enfranchise AMSO data in the model. As mentioned in Subtask 4.7, they have added triaxial testing on an AMSO sample (CT scanned last quarter) to increase the mechanical properties data available. The testing in SubTask 4.7 will also provide some basis for inferring permeability and porosity relationships with temperature.

Segmented linearization and the development of constitutive modeling surfaces is proceeding on AMSO data. The project team concentrated this quarter on the strain information from a second vendor. Now, all data from New England Research and MetaRock have been fitted (as has been described in previous quarterly reports). Subsidence and compaction are also being evaluated. The effort is to look at geomechanical and coupled production phenomena.

The project team has engaged another researcher to use commercial geomechanics software. Originally this was going was a post-doctoral researcher, but they have been fortunate to find an MS candidate to carry out this work. Hence, there will be a thesis to go with other publications.

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)

During this quarter, the Subtask 7.3 team completed their first deliverable, a progress report on V/UQ of the Generation 1 simulation with AMSO experimental data. It is attached as Appendix C.

Additionally, team members (1) continued to run simulations of the January 2012 heater experiment test that was conducted by AMSO at their pilot test facility near Rifle, Colorado, and (2) began simulations of AMSO's March 2013 heater experiment. Team members continue to work closely with AMSO scientists with the goal of using simulation results to help the scientists answer questions and gain insight into their process.

The project team has developed a relationship for density as a function of grade. Previously, they only had density for three specific grades of oil shale. Based on the core samples from the AMSO site, they were able to generate an equation that describes the variation of density as a function of grade. Since the simulations account for oil shale grade variability as a function of depth with 15 cm increments, this means the density variation is a function of well depth too.

Team members have begun research on the implementation of kinetic compositional models into their Generation 2 simulation. First, background research is needed to determine which models are most applicable to the AMSO heater test and can be implemented into their simulation methodology. This background research is addressing all issues related to implementing kinetic models into the simulations, including the transport of products through the shale to the collection well and the possibility of changing shale properties as the shale formation is being retorted. This Generation 2 simulation is not just an incremental improvement over the Generation 1 simulation but is a completely new problem.

At this point, the project team does not have any geomechanics information that would guide them in changing the simulation geometry. Therefore, they have eliminated geomechanics of the AMSO process from their simulation. The milestone to perform a Generation 2 simulation that incorporates kinetics models and, if available, geomechanics information, has been modified to only include the incorporation of kinetics models. The due date for this milestone has been delayed until next quarter.

CONCLUSIONS

Several subtasks have been completed or are nearing completion. Work is progressing on the final joint papers for Subtasks 4.3 and 4.9, which focus on kerogen structures and pyrolysis models. The topical report for Subtask 6.1, a policy analysis of the Canadian oil sands experience, has undergone final review and will be submitted in August 2013. With the release of the market assessment report (Subtask 6.3) in this quarter, other subtasks which are tied to the assessment are wrapping up as well. This list includes Subtasks 3.1 (Phase I) and 6.1, both is which will be completed in the next quarter. Work on Subtask 4.8, the predictive geologic model, has been completed and the data is being prepared for upload to the ICSE repository. With the completion of these projects and the hiring of additional personnel, Subtasks 3.1, 3.3, and 3.4 (all related to Basin-scale modeling of conventional and unconventional oil development), 4.7 and 7.1 (both related to geomechanical processes), and 4.2 (reservoir modeling) have made significant progress during this quarter. Researchers performing simulation work on HPC tools (Subtasks 4.1 and 7.3) continued to engage industry as they improved the capabilities of the tools for resolving the heterogeneous nature of oil shale. Several of the research projects were highlighted in presentations at the 2013 University of Utah Unconventional Fuels Conference, held on May 7, 2013 in Salt Lake City, Utah.

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											
	Q13		Q14		Q15		Q16					
	10/01/12 - 12/31/12		01/01/13 - 03/31/13		04/01/13 - 06/30/13		07/01/13 - 09/30/13					
	Q13	**Total**	Q14	**Total**	Q15	**Total**	Q16	**Total**		**Total**		**Total**
Baseline Cost Plan												
Federal Share	146,824	**5,235,073**	146,824	**5,381,897**	146,824	**5,528,721**	133,794	**5,662,515**				
Non-Federal Share	36,705	**1,306,563**	36,705	**1,343,268**	36,705	**1,379,973**	35,906	**1,415,879**				
Total Planned	183,529	**6,541,636**	183,529	**6,725,165**	183,529	**6,908,694**	169,700	**7,078,394**				
Actual Incurred Cost												
Federal Share	128,349	**4,485,377**	180,613	**4,665,990**		**4,665,990**		**4,665,990**				
Non-Federal Share	79,871	**1,051,976**	62,354	**1,114,330**		**1,114,330**		**1,114,330**				
Total Incurred Costs	208,220	**5,537,353**	242,967	**5,780,320**		**5,780,320**		**5,780,320**				
Variance												
Federal Share	18,475	**749,696**	-33,789	**715,907**		**862,731**		**996,525**				
Non-Federal Share	-43,166	**254,587**	-25,649	**228,938**		**265,643**		**301,549**				
Total Variance	-24,691	**1,004,283**	-59,438	**944,845**		**1,128,374**		**1,298,074**				

Note: A revised cost plan was not received for this quarter, so this cost plan is from the previous quarterly report.

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		NCE will delay this meeting until 2014
3.0	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	Mar-13		Milestone delayed pending further development of oil/ gas production model
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		Due date has been revised to reflect personnel availability
	Demonstrate full functionality for conventional & unconventional oil development in Uinta Basin	Mar-14		
4.0	Liquid Fuel Production by In-Situ Thermal Processing of Oil Shale/Sands			
4.1	Development of CFD-based simulation tool for in-situ thermal processing of oil shale/ sands			

ID	Title/Description	Planned Completion Date	Actual Completion Date	Milestone Status
	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
4.5	In situ pore physics			
	Complete pore network structures & permeability calculations of Skyline 16 core (directional/anisotropic, mineral zones) for various loading conditions, pyrolysis temperatures, & heating rates	Mar-12	Mar-12	Discussed in April 2012 quarterly report for 1 loading condition; samples never received from Subtask 4.7, so PI dropped loading condition as variable
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	Dec-12		Testing has begun but is not complete
	Complete thermophysical & geomechanical property data analysis & validation	Mar-13		Will complete once experimental matrix is complete

ID	Title/Description	Planned Completion Date	Actual Completion Date	Milestone Status
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 April 2012 quarterly report
	Development of a structural model of kerogen & bitumen	Jun-12	Jun-12	Discussed in July 2012 quarterly report
5.0	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
6.0	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	Will be uploaded by Aug. 15, 2013

ID	Title/Description	Planned Completion Date	Actual Completion Date	Milestone Status
7.0	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
7.1	Geomechanical model			
	Infer permeability-porosity-temperature relationships, develop model that can be used by other subtasks	Dec-12		Partially completed as described in this report. Addn'l work will be completed in July 2013
	Make experimental recommendations	Aug-13		
	Basic reservoir simulations to account for thermal front propagation	Dec-13		
	Evaluation of flow mechanics	Dec-13		
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	Jun-13		Delayed until 3Q 2013

NOTEWORTHY ACCOMPLISHMENTS

The release of the oil shale and oil sands market assessment report by the Subtask 6.3 team represents the culmination of several years of work and the input of many individuals and groups in academia, government, and industry.

PROBLEMS OR DELAYS

Personnel needed to wrap up several subtasks (3.3, 3.4, 4.2, 4.3, 7.1) have been hired, and significant progress was made this quarter. However, revised timelines are proposed for several of the subtasks to better reflect the actual project timelines. In Subtask 4.7, the experimental program at high temperatures has been challenging. While the vessel is functional under uniaxial compression, upcoming tests will be triaxial, meaning the confining pressure system will need to be debugged. Additionally, the separator/condensation system will need to be tested.

RECENT AND UPCOMING PRESENTATIONS/PUBLICATIONS

Badu, S., Pimienta, I. S. O., Orendt, A. M. Facelli, J. C. & Pugmire, R. J. (2012). Modeling of asphaltenes: Assessment of sensitivity of ^{13}C SSNMR to molecular structure. *Energy & Fuels, 26(4),* 2161-2167.

Fletcher, T. H., Orendt, A. M., Facelli, J. C., Solum, M. S., Mayne, C. L. & Deo, M. (2012, May 15). Kinetics of Uinta Basin oil shale pyrolysis. Paper presented at the 2012 University of Utah Unconventional Fuels Conference, Salt Lake City, UT.

Ruple, J. (2012, May 15). Wilderness quality lands and unconventional fuel development. Paper presented at the 2012 University of Utah Unconventional Fuels Conference, Salt Lake City, UT.

Tiwari, P. (2012). Oil shale Pyrolysis: Benchscale experimental studies and modeling. Ph.D. dissertation, Department of Chemical Engineering, University of Utah.

Tiwari, P., Deo, M., Lin C. L. & Miller, J.D. (2012, October). Characterization of the oil shale core pore structure before and after pyrolysis. Paper presented at the 2012 AICHE Annual Meeting, Pittsburgh, PA, October 28-November 2, 2012.

Vanden Berg, M. D., Birgenheier, L. P. & Rosenberg M. J. (2012, September). Core-based sedimentologic, stratigraphic, and geochemical analysis of the lacustrine upper Green River Formation, Uinta Basin, Utah: Implications for conventional and unconventional petroleum development. Paper presented at the 2012 American Association of Petroleum Geologists - Rocky Mountain Section Meeting, Grand Junction, CO.

Rosenberg, M.J., Birgenheier, L.P, & Vanden Berg, M.D. (2012, October). Sedimentology and sequence stratigraphy of the Green River Formation, eastern Uinta Basin, Utah. Paper presented at the 32nd Oil Shale Symposium, Golden, CO, October 15-19, 2013.

Burnham, A., Day, R., Switzer, L., McConaghy, J., Hradisky, M., Coates, D., Smith, P., Foulkes, J., La Brecque, D., Allix, P., Wallman, H. (2012, October). Initial results of the AMSO RD&D pilot test program. Paper presented at the 32nd Oil Shale Symposium, Golden, CO, October 15-19, 2013.

Deo, M. (2012, October). *Oil shale liquefaction: Modeling and reservoir simulation*. Short course presentation to Statoil, Trondheim, Norway.

Deo, M. (2012, October). *Oil shale conversion to liquids: Experimental aspect*. Short course presentation to Statoil, Trondheim, Norway.

Fletcher, T. H. (2012, October). *Oil shale 1: Chemical structure and pyrolysis*. Short course presentation to Statoil, Trondheim, Norway.

McLennan, J. (2012, October). *Legacy and new geomechanical measurements of oil shale*. Short course presentation to Statoil, Trondheim, Norway.

Smith, P. J. (2012, October). *Multiscale simulation*. Short course presentation to Statoil, Trondheim, Norway.

Smith, P. J. (2012, October). *A description of a UQ-predictive validation framework for application to difficult engineering problems*. Short course presentation to Statoil, Trondheim, Norway.

Orendt, A. , Pimienta, I. S. O., Badu, S., Solum, M., Pugmire, R. J., Facelli, J. C., Locke, D. R., Winans, R. E., Chapman, K. W. & Chupas, P. J. (2012). Three-dimensional structure of the Siskin Green River oil shale kerogen model: A comparison between calculated and observed properties. *Energy and Fuels, 27*, 702-710.

Spinti, J. (2013, January 10). Presenter/panelist - *The real impact of oil shale and oil sands development in Utah.* 2013 Governor's Energy Development Summit, Salt Lake City, UT.

Hradisky, M., Smith, P. J. & Burnham, A. (2013, March). *STAR-CCM+ simulations of in-situ thermal treatment of oil shale*. Paper presented at the STAR Global Conference, Orlando, FL, March 18-20, 2013.

Orendt, A. M., Solum, M. S., Facelli, J. C., Pugmire, R. J., Chapman, K. W., Winans, R. E. & Chupas, P. (2013, April). Characterization of shale and kerogen from a Green River oil shale core, ENFL-535. Paper presented at the 245th American Chemical Society National Meeting, New Orleans, LA, April 7-11, 2013.

Birgenheier, L. P. (2013, May 7). Presenter/panelist - *Constructing a basin-wide geologic model*. University of Utah Unconventional Fuels Conference, Salt Lake City, UT.

Smith, P. J. (2013, May 7). Presenter/panelist - *Simulation of in situ production process using computational fluid dynamics*. University of Utah Unconventional Fuels Conference, Salt Lake City, UT.

Spinti, J. P. (2013, May 7). Presenter/panelist - *Assessment of unconventional fuels development costs*. University of Utah Unconventional Fuels Conference, Salt Lake City, UT.

Birgenheier, L.P., Plink-Bjorklund, P., Vanden Berg, M.D., Rosenberg, M., Toms, L. & Golab, J. (2013). *A genetic stratigraphic framework of the Green River Formation, Uinta Basin, Utah: The impact of climatic controls on lake evolution*. Paper presented at the American Association of Petroleum Geologists Annual Meeting, Pittsburgh, PA, May 22-25, 2013.

Vanden Berg, M. D., Eby, D. E., Chidsey, T. C. & Laine, M.D. (2013). *Microbial carbonates in cores from the Tertiary (Eocene) Green River Formation, Uinta Basin, Utah, U.S.A.: Analogues for non-marine microbialite oil reservoirs worldwide*. Paper presented at

Microbial Carbonates in Space and Time: Implications for Global Exploration and Production, The Geological Society, London, United Kingdom, June 19-20, 2013.

Rosenberg, M. J. (2013). Facies, stratigraphic architecture, and lake evolution of the oil shale bearing Green River Formations, eastern Uinta Basin, Utah. M.S. thesis, Department of Geology and Geophysics, University of Utah.

Tiwari, P., Deo, M., Lin, C. L. & Miller, J.D. (2013, May). Characterization of oil shale pore structure before and after pyrolysis by using X-ray micro CT. *Fuel*, *107*, 547–554.

Pugmire, R. J., Fletcher, T. H., Hillier, J., Solum, M., Mayne, C. & Orendt, A. (2013, October). Detailed characterization and pyrolysis of shale, kerogen, kerogen chars, bitumen, and light gases from a Green River oil shale core. Abstract submitted to the 33rd Oil Shale Symposium, Golden, CO, October 14-16, 2013.

Fletcher, T. H., Gillis, R., Adams, J., Hall, T., Mayne, C. L., Solum, M.S. & Pugmire, R. J. (2013, October). Characterization of pyrolysis products from a Utah Green River oil shale by ^{13}C NMR, GC/MS, and FTIR. Abstract submitted to the 33rd Oil Shale Symposium, Golden, CO, October 14-16, 2013.

Wilkey, J., Spinti, J., Ring, T., Hogue, M. & Kelly, K. (2013, October). Economic assessment of oil shale development scenarios in the Uinta Basin. Abstract submitted to the 33rd Oil Shale Symposium, Golden, CO, October 14-16, 2013.

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.

Bauman. J. H. & Deo, M. D. (n.d.) Simulation of a conceptualized combined pyrolysis, in situ combustion, and CO_2 storage strategy for fuel production from Green River oil shale. Submitted to *Energy and Fuels*.

Orendt, A. M., Solum, M. S., Mayne, C. L., Pugmire, R. J., Facelli, J. C., Locke, D. R., Winans, R. E., Chapman, K. W. & Chupas, P. J. (n.d.). Characterization of shale, kerogen and bitumen from a Green River oil shale core. Manuscript in preparation.

Fletcher, T. H., Gillis, R., Adams, J., Hall, T., Mayne, C. L., Solum, M.S., and Pugmire, R. J. (n.d.). Characterization of pyrolysis products from a Utah Green River oil shale by ^{13}C NMR, GC/MS, and FTIR. Manuscript in preparation.

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APPENDIX A. Agenda - 2013 University of Utah Unconventional Fuels Conference.

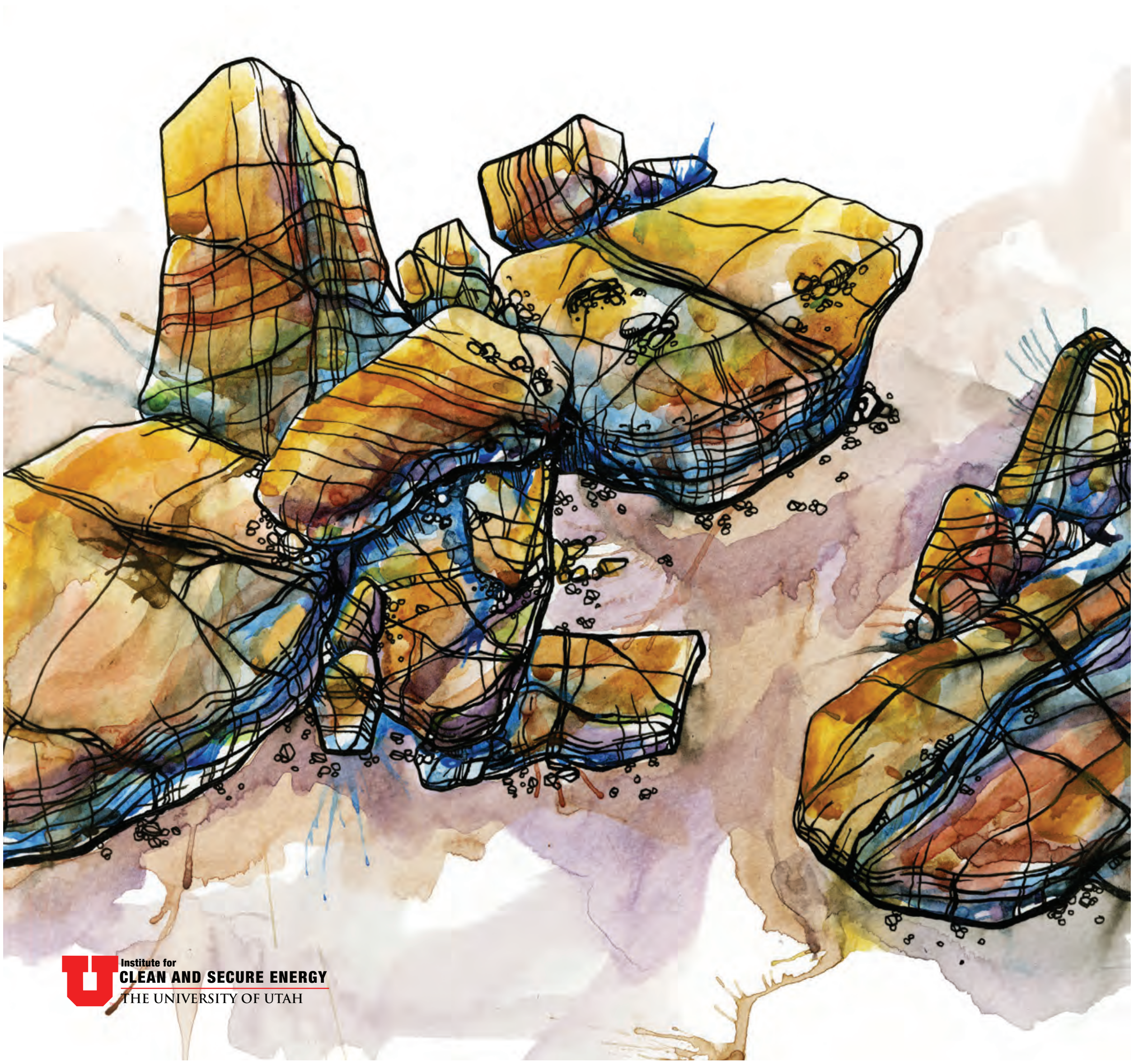
University of Utah

May 7th, 2013

UNCONVENTIONAL FUELS CONFERENCE

Oil Shale & Oil Sands Development in the Western U.S.

AGENDA



8:30 a.m. - Welcome

Philip J. Smith, Director, Institute for Clean & Secure Energy, Professor, Department of Chemical Engineering, The University of Utah

8:45 a.m. - Morning Plenary - Simulation needs for unconventional fuels

Pierre Allix, Unconventional Resources Program Manager, Total S.A.

Morning Session - Role of simulation in unconventional fuels development

9:15 a.m. - High performance computing in unconventional fuel production

Philip J. Smith, Director, Institute for Clean & Secure Energy, Professor, Department of Chemical Engineering, The University of Utah

9:35 a.m. - Simulation of in situ production processes in reservoir modeling

Hai Huang, Senior Research & Development Scientist, Idaho National Laboratory

9:55 a.m. - Role of simulation in carbon management

Brian McPherson, Associate Professor, Department of Civil & Environmental Engineering, The University of Utah

10:15 a.m. - Constructing a basin-scale geologic model

Lauren Birgenheier, Assistant Professor, Department of Geology & Geophysics, The University of Utah

10:35 a.m. - Morning break

11:00 a.m. - Panel discussion moderated by Prof. Philip J. Smith

12:00 p.m. - Lunch

1:00 p.m. - Afternoon Plenary - Energy development on federal lands in Utah: Is government a development constraint?

Juan Palma, State Director, Bureau of Land Management

Afternoon session – Constraints on unconventional fuels development

1:30 p.m. - Uinta Basin products and transportation: Constraints and opportunities

Neil Pogorelsky, Principal Economist, HDR Decision Economics

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1:50 p.m. - Uinta Basin air quality

Seth Lyman, Executive Director, Bingham Research Center, Utah State University

2:10 p.m. - Impacts of unconventional fuels development in the Uinta Basin

Anne Mariah Tapp, Law & Public Policy Fellow, Grand Canyon Trust

2:30 p.m. - Financing unconventional fuels projects

Robert Wood, Partner, Renewable Tech Ventures

2:50 p.m. - Assessment of unconventional fuels development costs

Jennifer Spinti, Research Associate Professor, Department of Chemical Engineering, The University of Utah

3:05 p.m. - Afternoon break

3:30 p.m. - Panel discussion moderated by Research Prof. Jennifer Spinti

4:30 - Conference concludes

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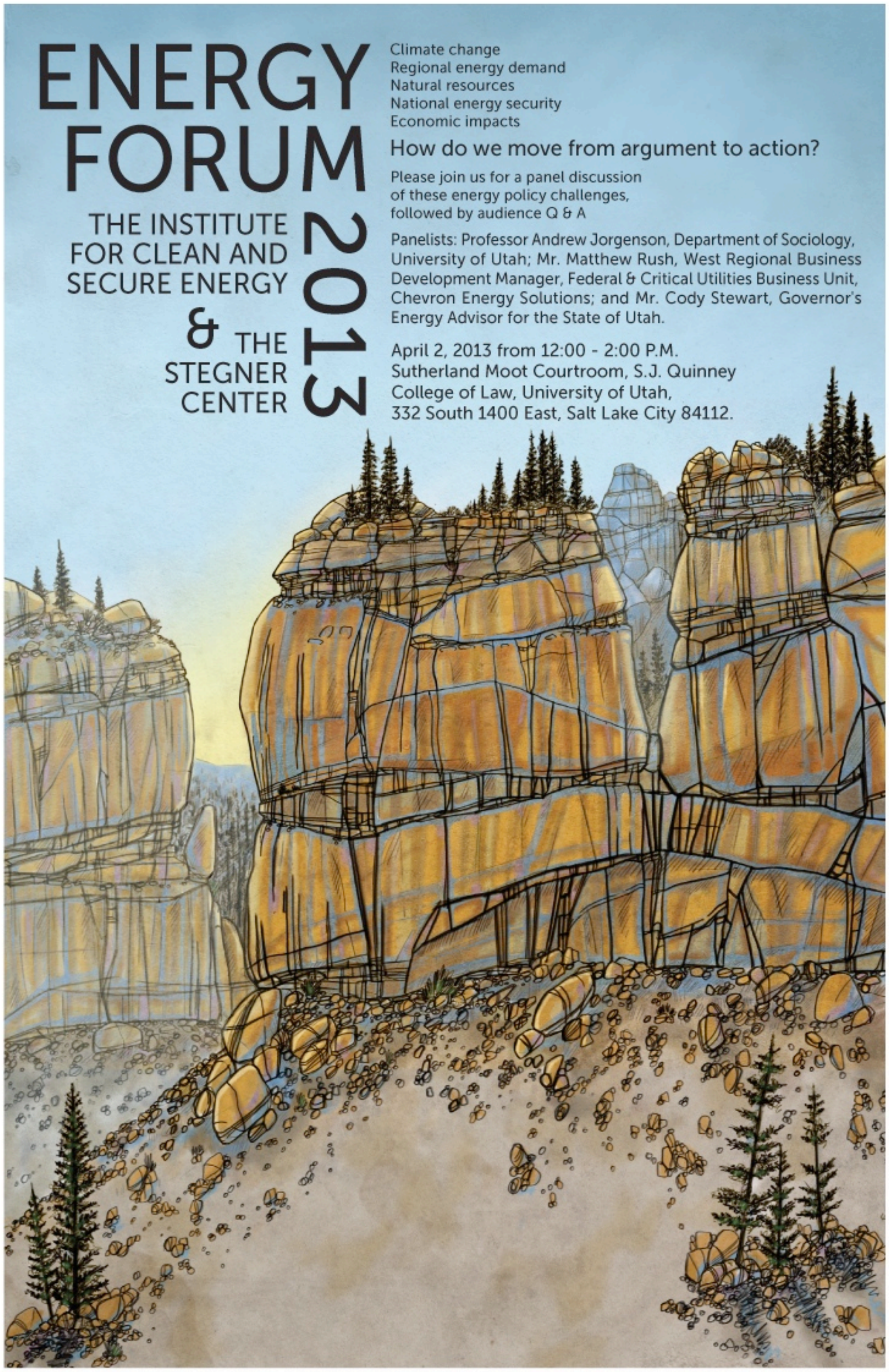
APPENDIX B. Announcement - 2013 Energy Forum



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APPENDIX C. Subtask 7.3 Deliverable - Progress report on “V/UQ of Generation 1 Simulator with AMSO Experimental Data.”

V/UQ of Generation 1 Simulator with AMSO Experimental Data

Subtask 7.3 Progress Report

July 31, 2013

1. Introduction

As part of the capstone project, we have been working to create a high performance computing (HPC) computational fluid dynamics (CFD) simulation tool that would allow us to simulate in-situ thermal heating of oil shale. Using our HPC CFD tool, in the first phase of the project we have performed validation and uncertainty quantification (V/UQ) study of the heater test conducted by American Shale Oil (AMSO) company at their pilot test facility located in Rifle, CO.

2. Problem Description

American Shale Oil company started as EGL Resources, an independent oil and gas company, which, in 2005, applied for BLM RD&D lease in the Piceance Basin near Rifle, Colorado. In 2007, the BLM has granted the RD&D lease to EGL Resources. However, in 2008, EGL Resources has been acquired by telecommunication corporation IDT and subsequently, EGL Resources has been renamed to American Shale Oil. In 2009, the French oil company Total acquired 50% of AMSO and approved pilot test plans. The pilot test facility started construction in 2010. In 2011, IDT spun-off AMSO and other energy ventures to form Genie Energy. Also, later that year, AMSO completed construction of the pilot test facility, shown in Figure 1, and started to perform a heater test to evaluate performance of the heater underground, as well as collect temperature response data from nearby tomography (TM) wells that would help them experimentally evaluate and validate composition of the shale formation. Figure 2 shows a close up of the heater wellhead and oil and gas processing facilities, along with location of TM wells at which not only geophysical and geological, but also temperature data were collected.

A schematic representation of the cross-sectional view of the AMSO pilot test facility is shown in Figure 3. In this plot, the left part of the figure shows the relative location of the triangular convection loop with respect to the ground level, whereas the

Figure 1. Aerial view of AMSO pilot test facility near Rifle, Colorado, with description of the site. Image provided by AMSO.

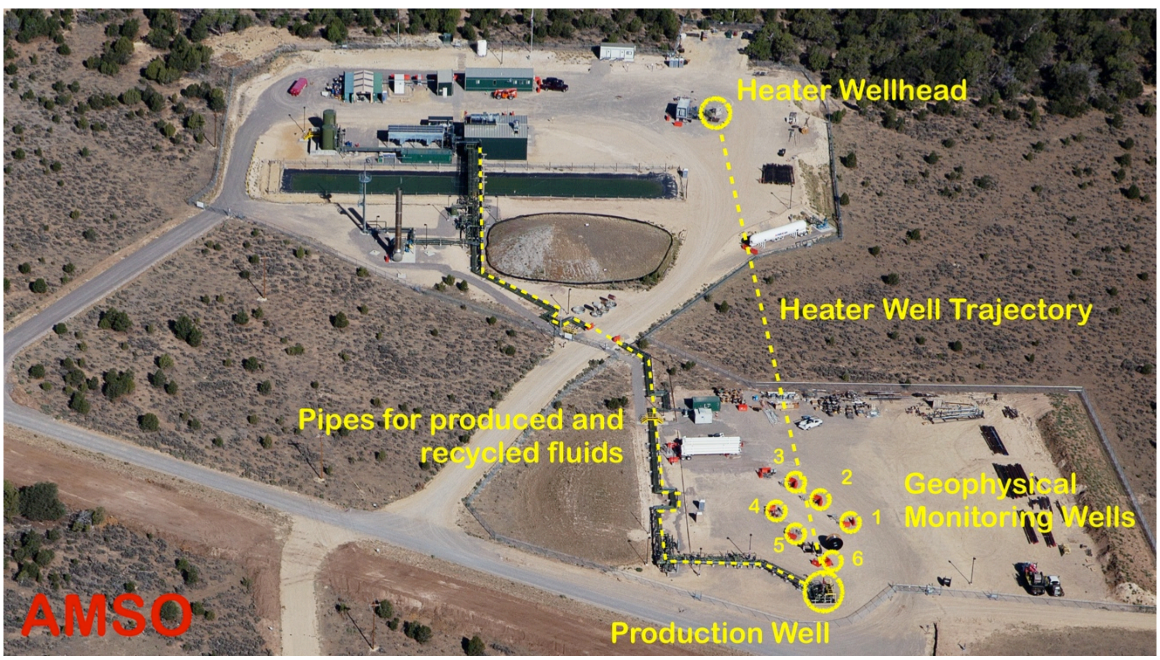

Figure 2. Aerial view of the production and geophysical tomography wells and their location. Image provided by AMSO.

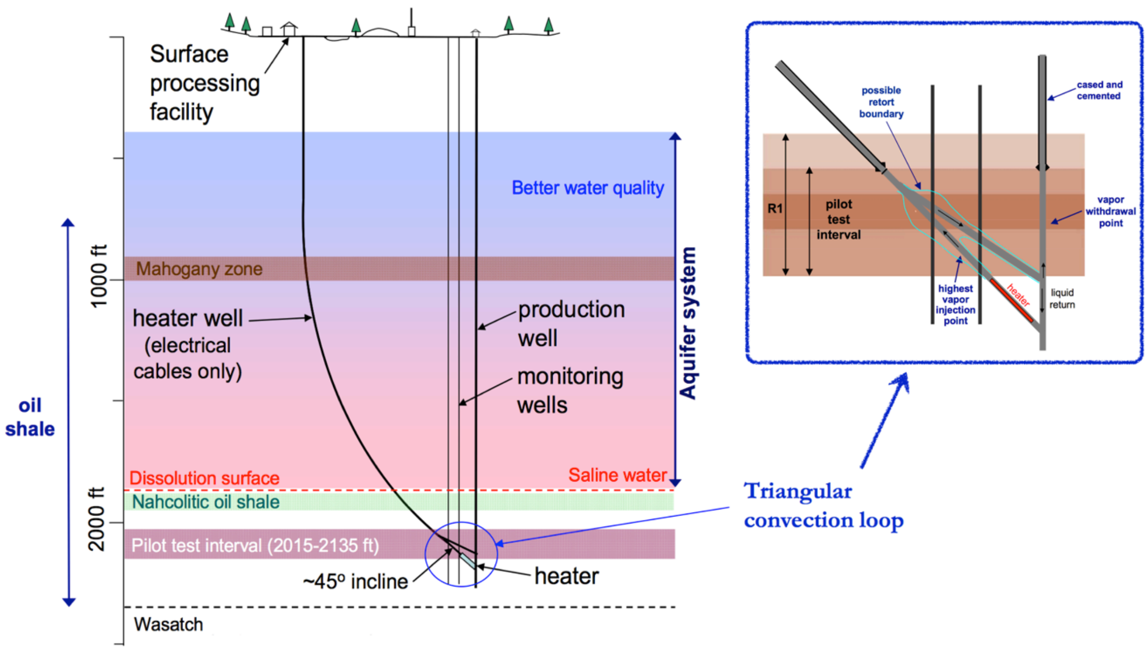

Figure 3. Schematic of AMSO pilot test facility, along with close up of the retorting section (triangular convection loop). Image provided by AMSO.

small, inset subfigure on the right shows a close up of the triangular convection loop, which was designed to test AMSO's CCR process. For this process to work, the heater is submerged in liquid oil in the lower later well, which has been pumped into the well or produced early on in the retorting interval from shale nearby the heater. This oil is then brought to boil, and the vapors from this process travel up the lower lateral well, and then down the upper lateral well. These vapors then condense on the walls of the upper lateral well and drain into the production well. Here, the condensed oil is mixed with the oil that is already there. Therefore, this fluid is constantly mixed, but the vapors increase the heating footprint of the heater – so instead of requiring direct heating contact, the hot vapors help to retort shale which is physically located far away from the heater.

In January 2012, AMSO started first in the series of heater tests to evaluate their retorting process as well as gain more insight into performance of the heater and temperature response collected at TM wells. This also provides insight into geophysical aspects of this process, such properties of the shale at various depths. Using this experiment, AMSO was able to narrow down elements of their experimental procedure that either need improvement or complete redesign. Furthermore, coupled with simulation, they could obtain new set of information that would allow them to understand, and possibly provide opportunity to modify and improve the current process.

To construct a CAD geometry for our simulation that would represent the actual AMSO process, we have used gyro survey data provided by AMSO, which was collected during drilling of each well. Therefore, our geometry represents the actual well geometry of the AMSO pilot test wells and is shown in Figure 4, Figure 5 and Figure 6. These figures show the irregular length and shapes of the tomography wells. We have spent significant amounts of time creating this geometry and collaborating with AMSO scientists, since locations of all tomography wells with respect to the convection loop (which comprises from the lower and upper laterals, as well as the production well) are extremely important for result comparison. The mesh we have used for our computations is shown in Figure 7. It contains 9 million polyhedral elements and in our simulations we model only heat transfer through the solid block of shale. For our computations, TM wells were assumed to be made from solid concrete.

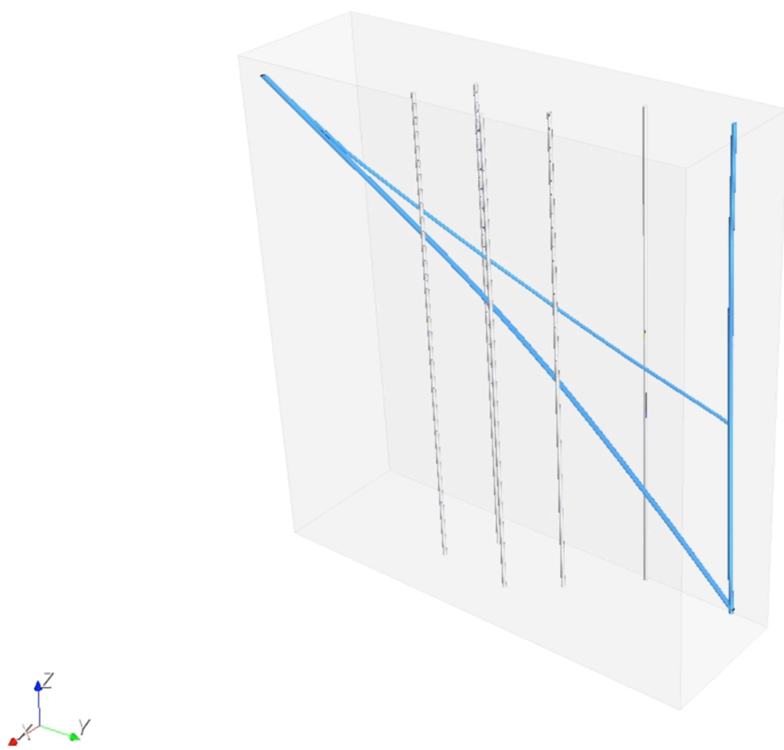

Figure 4. CAD geometry used in simulation of the AMSO heater test. The wells were constructed from the actual field gyro surveys. The tomography wells are colored in gray.

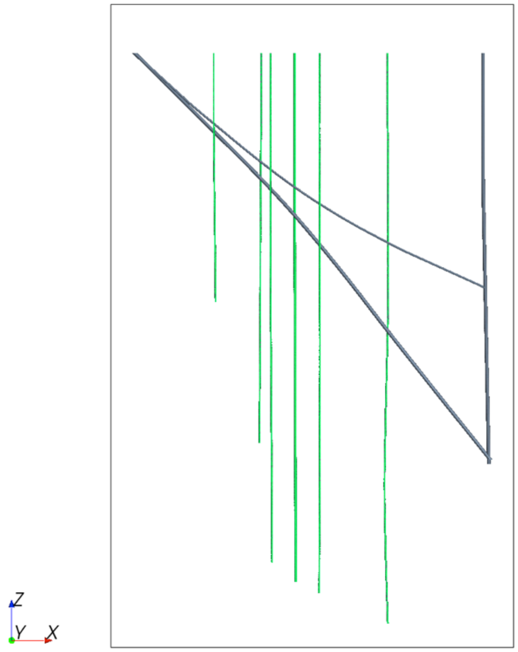

Figure 5. Side view of the AMSO heater test geometry.

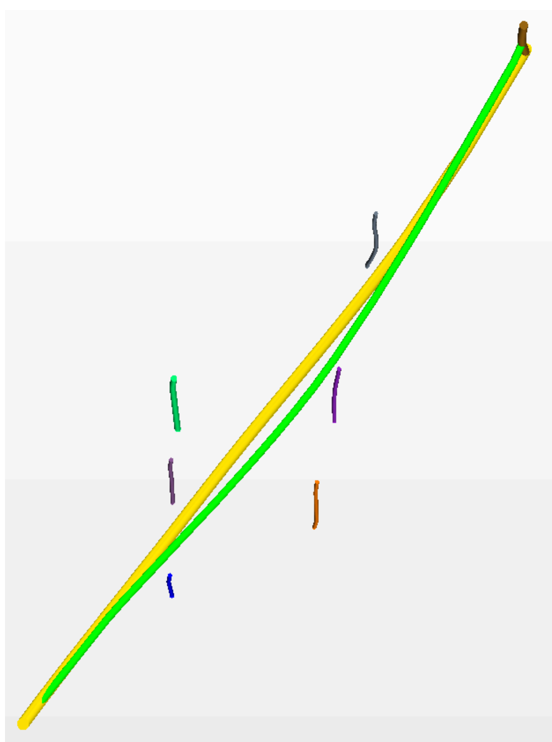

Figure 6. Top view of teh AMSO heater test geometry, which clearly shows the irregular shape of the veritcal tomography wells.

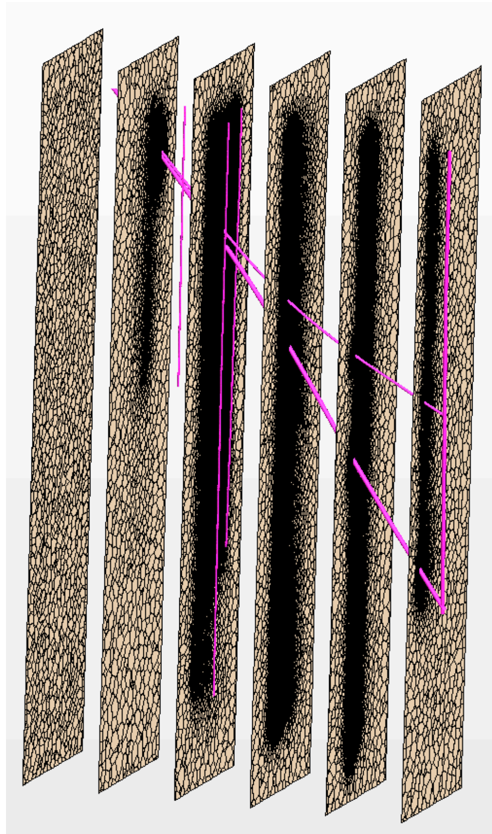

Figure 7. Computational mesh used for simulations of the conduction heat transfer through the shale formation.

AMSO heated the shale formation using a heater placed in the lower lateral well. The heater was brought to about 700 K over a period of few weeks back in January 2012. After that, the heater was turned off. AMSO provided us with the exact temperature distribution along the heater as a function of time, which we have used as a temperature boundary condition for our simulations, as shown in Figure 8. Since the start of this heater pulse test in January 2012, to this day, AMSO continuously monitors and measures temperatures in all wells on daily basis. Therefore, they were able to provide us with the experimental data for the heat pulse response at each respective TM wells.

Another important part was to match the properties of the formation in the simulation to the properties of the actual formation at the AMSO site. AMSO provided us with a plot of grade of shale (where grade of shale refers to oil yield measured as gallons of oil per ton) as a function of depth, which we then classified into three categories, as shown in Figure 9. Oil shale grades with yield of 0 to 17.5 gallons of oil per ton (GOPT) were grouped into category represented by properties of oil shale grade of 10 GOPT. Oil shale grades between 17.5 and 32.5 were categorized by properties of oil shale grade 25 GOPT, and oil shale grades above 32.5 were modeled using properties of oil shale grade 40 GOPT.

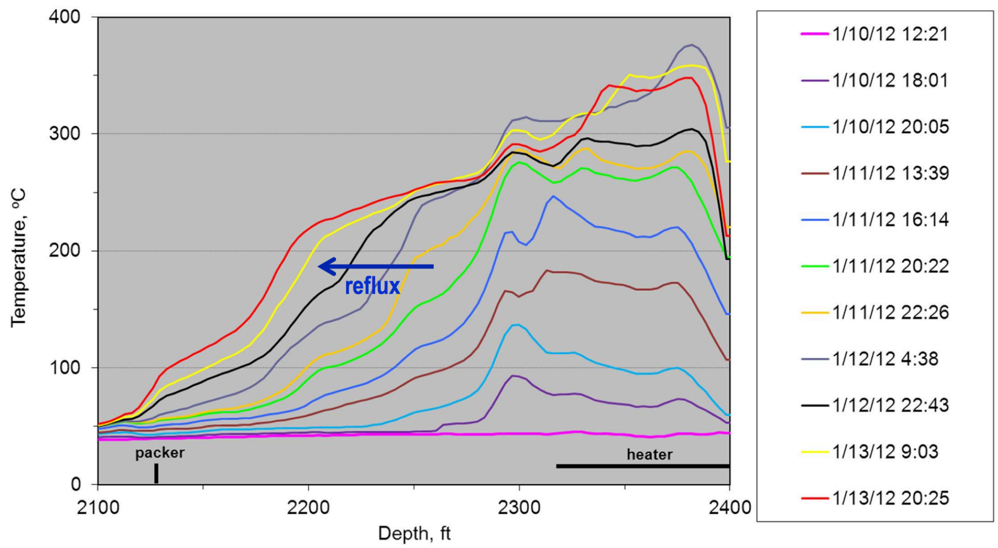

Figure 8. Heater temperature profiles at various times during the heating phase, which were used as temperature boundary conditions for our simulations.

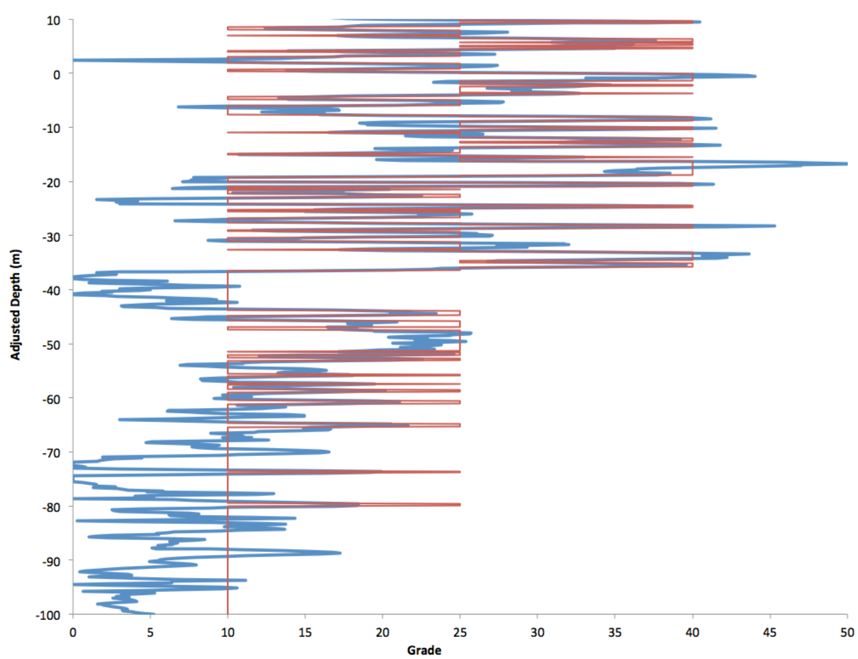

Figure 9. The shale grade variation as a function of depth at the AMSO test pilot facility (blue) and grade as a function of grade as implemented in our V/UQ simulations (red).

Therefore, all properties, such as density and thermal conductivity, were based on the three categorized grades of oil shale – 10, 25, and 40 GOPT. For instance, the density variation throughout our simulation domain can be seen in Figure 10. This figure only captures the three categories of oil shale, not the detailed variability found in at the AMSO test facility. Oil shale is further characterized by different thermal conductivity in the parallel direction (direction parallel to the layering) and in the perpendicular direction (direction perpendicular to the layering). This is depicted in Figure 11.

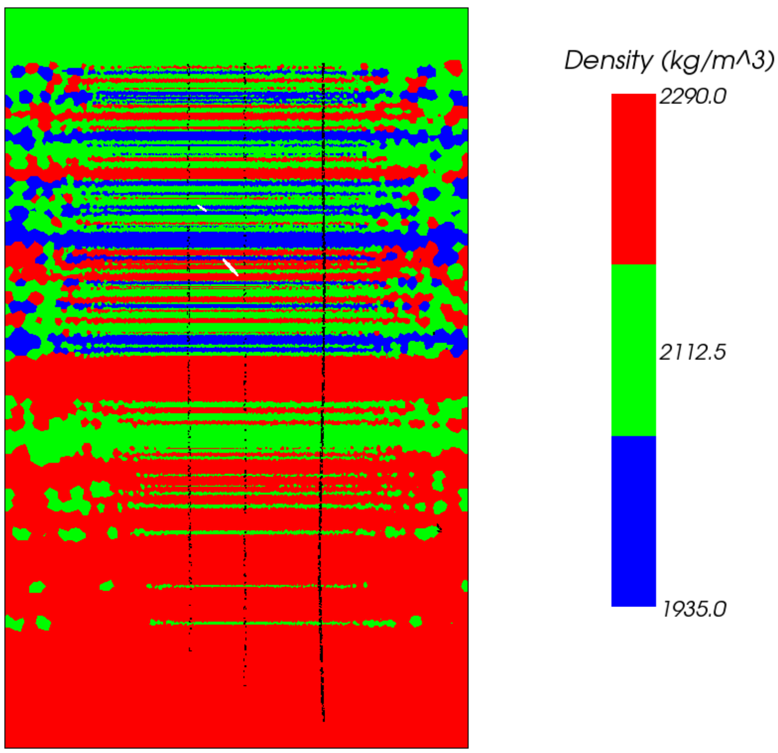

Figure 10. Density variation for the three categories of oil shale (10, 25, and 40 GOPT) inside the simulation domain, as adapted from the experimental data at the AMSO pilot test facility.

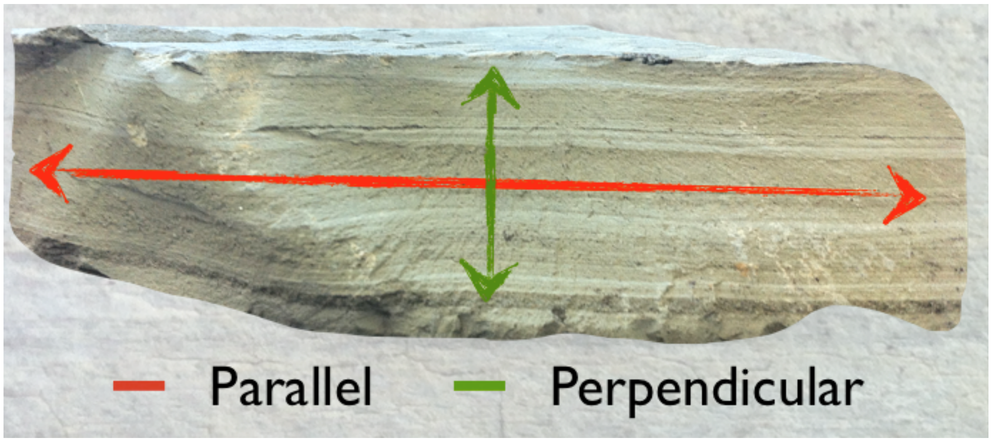

Figure 11. Parallel and perpendicular directions of thermal conductivity for oil shale.

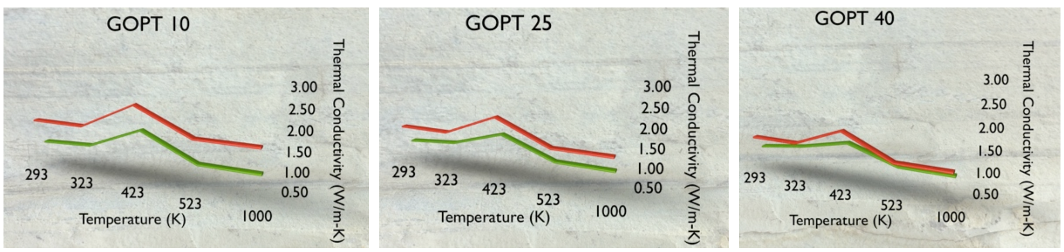

Figure 12. Parallel (red) and perpendicular (green) thermal conductivities for the thre categories of oil shale.

Figure 12 shows both parallel and perpendicular thermal conductivities for the three categories of oil shale, as implemented in our simulations. Therefore, the thermal conductivity was not only function of grade, but temperature as well.

For our V/UQ simulation studies we varied the shale properties in our simulation domain and observed the effect of temperature distribution at each respective TM well. Using our simulation strategy, we have decided to study the effect of number of grades included in the simulation, as well as the effect of thermal conductivity on the heat distribution throughout the formation. Figure 13 shows our V/UQ matrix. We have varied the number of shale groups in our domain from one to three. Therefore, for one set of computations we have assumed that our simulation domain is represented by three grades of shale – 10, 25, and 40 GOPT (first row of the V/UQ matrix). For a subsequent set of simulations, we assumed our simulation domain is represented by only one shale grade – 40 (second row of the V/UQ matrix), and therefore only applied properties respective to that shale grade. For the next set of computations, our simulation domain was represented by only shale grade 25, and for the last set of computations, the entire formation was represented by shale grade 10. Of course, for each set of computations based on grade, we also varied the thermal conductivity. For instance, for the simulation domain which was comprised from three shale groups, 10, 25, and 40 GOPT (first row of the V/UQ matrix), we ran one computation with constant thermal conductivity of 1.0 for the entire formation and for both parallel and perpendicular directions. The next simulation for the three grades of shale was conducted with thermal conductivity of 1.7, then with variable thermal conductivity as described previously (our baseline computation), then constant thermal conductivity 2.3, and lastly, with constant thermal conductivity of 2.5 for the entire simulation domain.

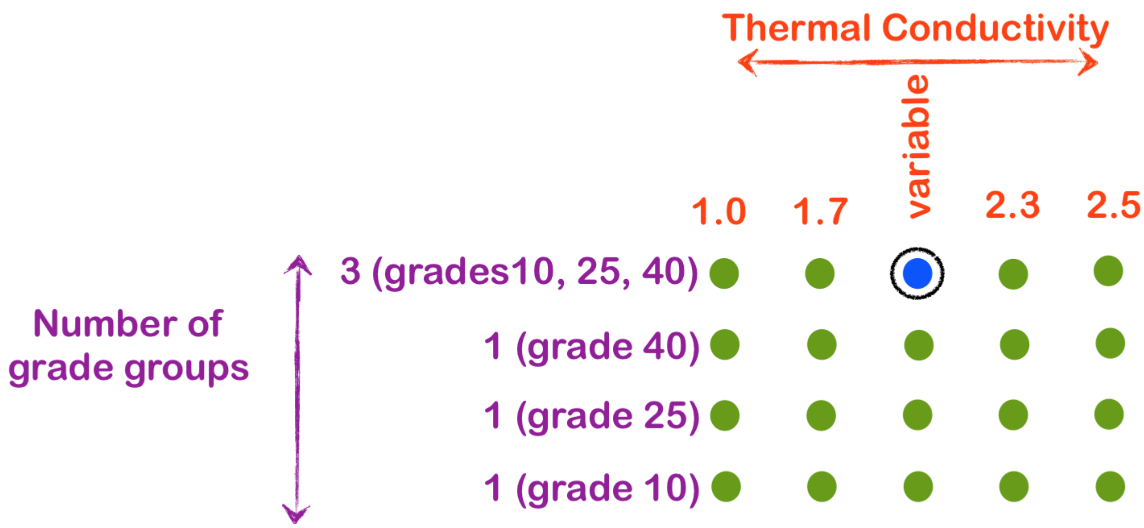

Figure 13. Our V/UQ matrix based on which we varied the number of shale groups and thermal conductivities in our simulations. The blue, circled point represents our baseline computation.

3. Results and Discussion

Using the simulation strategy outlined in the previous section, we were able to capture temperature response at each of the TM wells and compare them to the experimental results. One such comparison for our baseline case, at a specific time instance, can be seen in Figure 14. The two red lines, which represent the simulation results, show the temperatures at the near and far locations of the respective tomography well, while the blue markers show the experimental results, as graphically shown in Figure 15. As can be seen, our simulation results compare well to the AMSO experimental results, even though the simulation temperature response overpredicts the experimental temperature response. This behavior is seen for most TM wells.

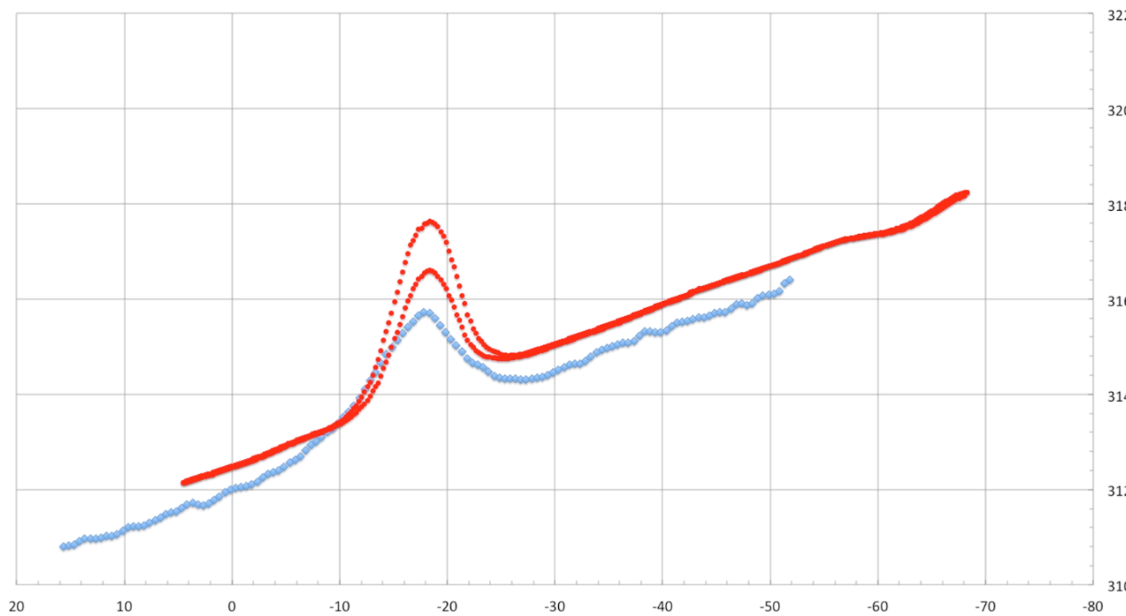

Figure 14. Comparison of temperature distribution in one of the tomography wells for simulation (red markers) and experimental results (blue markers). Horizontal axis represents depth, while the vertical axis represents the temperature.

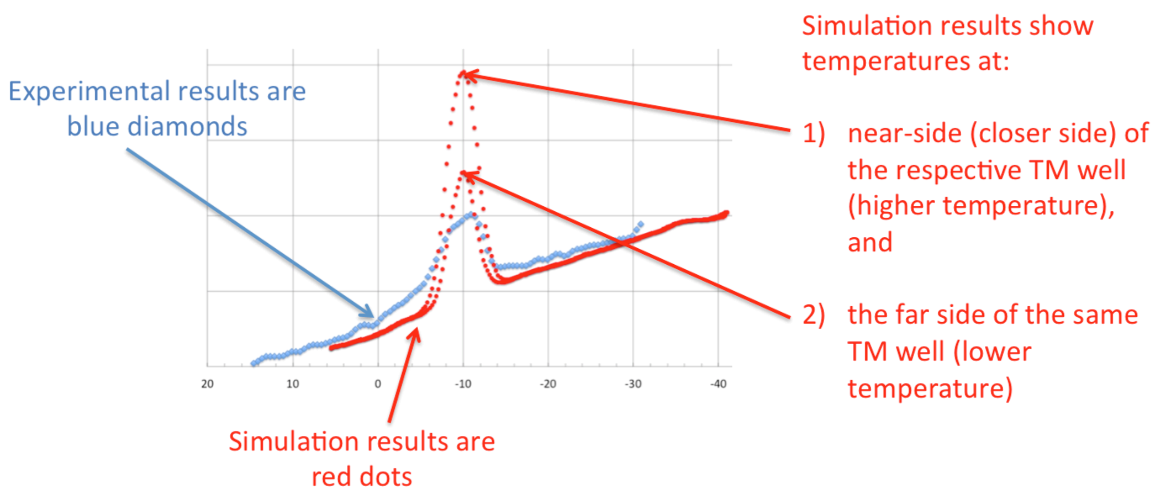

Figure 15. Description of temperature result comparisons between simulation and experiment.

We have further ran simulations for all 20 cases shown in our V/UQ matrix and we have plotted all results on the same plot to show the possible spread of temperature response at each well. Representative results are shown in Figure 16. As can be seen, the possible temperature response varies greatly based on the range of properties. This is shown graphically in Figure 17.

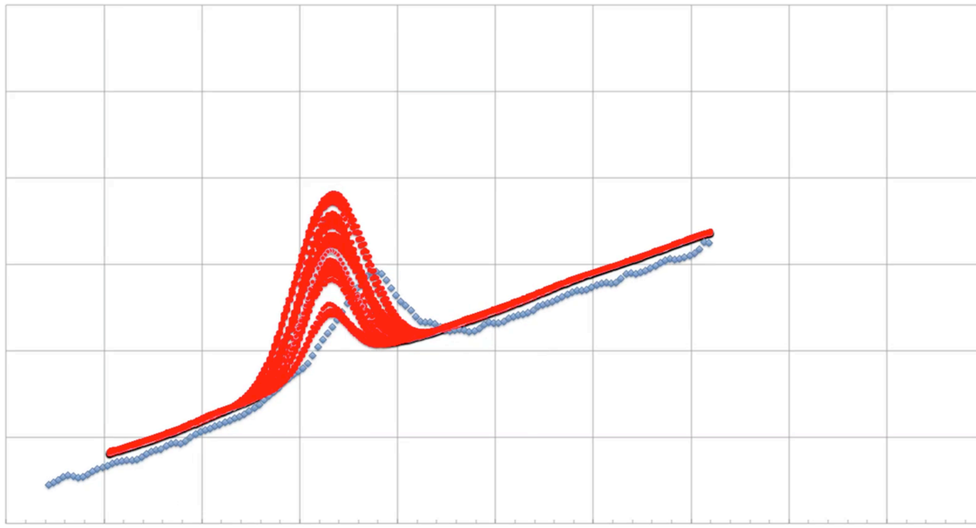

Figure 16. Comparison of temperature distribution for 20 simulations performed as a part of our VUQ studies in one of the tomography wells for simulation (red markers) and experimental results (blue markers). Horizontal axis represents depth, while the vertical axis represents the temperature.

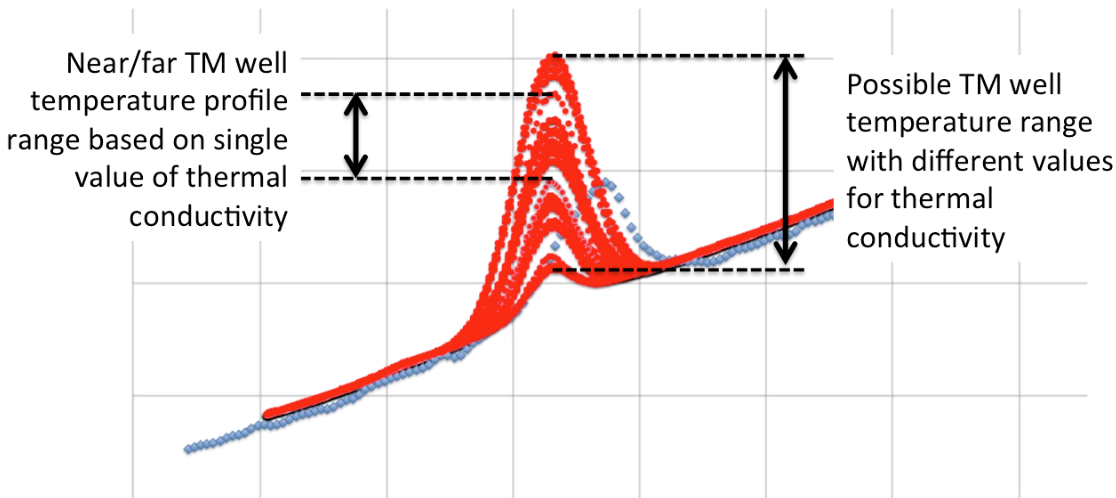

Figure 17. Comparison of possible temperature variablity when comparing one simulation with all simulations in the V/UQ matrix.

This methodology produces a range of possible temperature distributions for the AMSO heater test rather than a single temperature distribution. This allows us to conclude that the thermal response inside the formation is very sensitive to the physical properties of the shale, especially thermal conductivity. Therefore, to match the experimental temperature response using simulations, it is very important to match the physical properties of the shale formation for this specific site. Other important factors that could affect the simulation results are the accuracy of the geometry based on the gyro surveys, as well as implementation of the input temperature boundary condition.

Physically, the input temperature profile is based on fiber optic data collected at the wall of the heater, not at the wall of shroud which is touching the shale formation. Our overpredicted temperature response could be the result of overpredicting the actual temperature input into the formation.

4. Conclusion

Our V/UQ methodology allows us to study the effect of thermal conductivity as well as groupings of oil shale based on grade as a function of depth on the overall heat distribution for the January 2012 heater test conducted by AMSO at their pilot test facility located in Rifle, CO. Our simulations were constructed using as much detail as provided by AMSO – gyro surveys to construct the CAD simulation geometry, experimental temperature data for all wells, and properties of select grades of oil shale. Throughout this process, AMSO has been very willing to share their proprietary data with us, so we could construct the best simulation representation of their process.

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