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Feasibility Report on Alternative Methods for Cooling Cavern Oils at the U.S. Strategic Petroleum Reserve

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Abstract

Oil caverns at the U.S. Strategic Petroleum Reserve (SPR) are subjected to geothermal heating from the surrounding domal salt. This process raises the temperature of the crude oil from around 75°F upon delivery to SPR to as high as 130°F after decades of storage. While this temperature regime is adequate for long-term storage, it poses challenges for offsite delivery, with warm oil evolving gases that pose handling and safety problems. SPR installed high-capacity oil coolers in the mid-1990's to mitigate the emissions problem by lowering the oil delivery temperature. These heat exchanger units use incoming raw water as the cooling fluid, and operate only during a drawdown event where incoming water displaces the outgoing oil. The design criteria for the heat exchangers are to deliver oil at 100°F or less under all drawdown conditions. Increasing crude oil vapor pressures due in part to methane intrusion in the caverns is threatening to produce sufficient emissions at or near 100°F to cause the cooled oil to violate delivery requirements. This impending problem has initiated discussion and analysis of alternative cooling methods to bring the oil temperature even lower than the original design basis of 100°F.

For the study described in this report, two alternative cooling methods were explored: (1) cooling during a limited drawdown, and (2) cooling during a degas operation. Both methods employ the heat exchangers currently in place, and do not require extra equipment. An analysis was run using two heat transfer models, HEATEX, and CaveMan, both developed at Sandia

National Laboratories. For cooling during a limited drawdown, the cooling water flowrate through the coolers was varied from 1:1 water:oil to about 3:1, with an increased cooling capacity of about 3-7°F for the test cavern Bryan Mound 108 depending upon seasonal temperature effects. For cooling in conjunction with a degas operation in the winter, cavern oil temperatures for the test cavern Big Hill 102 were cooled sufficiently that the cavern required about 9 years to return to the temperature prior to degas. Upon reviewing these results, the authors recommended to the U.S. Department of Energy that a broader study of the cooling during degas be pursued in order to examine the potential benefits of cooling on all caverns in the current degasification schedule.

Table of Contents

1	Introduction.....	9
1.1	<i>Objective</i>	10
2	Approach.....	11
2.1	<i>Cooling during standby/degas</i>	11
2.1.1	Problem description.....	11
2.1.2	Applicable models.....	12
2.1.3	Heat exchanger problem setup	16
2.1.4	CAVEMAN model setup	17
2.2	<i>Cooling during a limited drawdown</i>	19
2.2.1	Applicable models.....	20
2.2.2	Problem setup	20
2.3	<i>Model validation</i>	21
2.3.1	Heat Exchanger Model.....	21
2.4	<i>Computing platform and operating system</i>	23
3	Results and Discussion	24
3.1	<i>Cooling during standby/degas</i>	24
3.1.1	Results from heat exchanger model	24
3.1.2	Results from thermal regain model	25
3.1.3	Discussion of cooling during standby/degas	31
3.2	<i>Cooling during a limited drawdown</i>	31
3.2.1	Summer cooling at $T_w = 85^\circ\text{F}$	31
3.2.2	Spring and Fall cooling at $T_w = 70^\circ\text{F}$	32
3.2.3	Winter cooling at $T_w = 55^\circ\text{F}$	33
3.2.4	Discussion of cooling during a limited drawdown.....	33
4	Conclusions.....	34
4.1	<i>Cooling during standby/degas</i>	34
4.2	<i>Cooling during a limited drawdown</i>	34
5	Recommendations for Future work	35
6	References.....	35
	APPENDIX A: Validation HTRI Sheets	36
	APPENDIX B: BH108 compositional data	44
	APPENDIX C: Tabular HEATEX model output for BM108 limited drawdown tests.	45
	APPENDIX D: Draft Degasification Schedule	47

<i>Draft degasification plant schedule as of 10/28/2004, provided by DynMcDermott Petroleum Operations Company.....</i>	<i>47</i>
APPENDIX E: BH102 Caveman Input Data.....	48
<i>Required input data for Cavern BH102 obtained from CaveMan Parameters workbook of CaveMan Version 4.0.</i>	<i>48</i>

List of Figures

Figure 1-1. Schematic of heat exchanger and cavern configuration during a normal maximum rate drawdown operation. Note that drawing is not to scale and contains only the major conceptual elements of the heat exchanger system.....	10
Figure 2-1. Schematic of major conceptual elements of the heat exchanger configured to cool during degas operations.	12
Figure 2-2. Schematic of major conceptual elements of the heat exchanger configured to cool during limited drawdown operation.....	19
Figure 3-1. Oil temperature at the heat exchanger outlet versus cooling water flowrate for winter, early spring, and middle spring cooling.	25
Figure 3-2. Predictions of cavern oil temperature for BH102. Cooling water flowrate = 90,000 bbl/day.....	26
Figure 3-3. Predictions of cavern brine temperature for BH102. Cooling water flowrate = 90,000 bbl/day.....	27
Figure 3-4. Predictions of cavern oil temperature for BH102. Cooling water flowrate = 130,000 bbl/day.....	27
Figure 3-5. Predictions of cavern brine temperature for BH102. Cooling water flowrate = 130,000 bbl/day.....	28
Figure 3-6. Predictions of cavern oil temperature for BH102. Cooling water flowrate = 180,000 bbl/day.....	28
Figure 3-7. Predictions of cavern brine temperature for BH102. Cooling water flowrate = 180,000 bbl/day.....	29
Figure 3-8. Predictions of cavern oil temperature for BH 102. Cooling water flowrate = 250,000 bbl/day.....	29
Figure 3-9. Predictions of cavern brine temperature for BH 102. Cooling water flowrate = 250,000 bbl/day.....	30
Figure 3-10. Predictions of cavern oil temperature for BH 102 with varied cooling water flowrate.	30
Figure 3-11. Summary plot of oil outlet temperature versus cooling water flow rate for BM108 test case as predicted by HEATEX. Oil inlet T = 123°F.	32

List of Tables

Table 2-1. Heat Exchanger Model calculation input for the case of cooling after a degas operation in Cavern BH102	17
Table 2-2. Oil properties for Bryan Mound Cavern 108	20
Table 2-3. Case 2 validation inputs and results.	22
Table 2-4. Case 3 validation inputs and results	23

List of Acronyms

BH	Big Hill SPR site
BM	Bryan Mound SPR site
CAVEMAN	Software system for SPR cavern pressure analysis, developed by Sandia National Laboratories
DOE	U.S. Department of Energy
GOR	Gas-Oil Ratio (units: standard cubic feet gas per barrel of oil)
HEATEX	Heat exchanger model used in this analysis, developed by Sandia National Laboratories
HTRI	Heat Transfer Research, Inc.
ICW	IntraCoastal Waterway
SNL	Sandia National Laboratories
SPR	Strategic Petroleum Reserve

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1 INTRODUCTION

Crude oil stored at the Strategic Petroleum Reserve (SPR) gains thermal energy from the warm (~140°F) domal salt surrounding the underground caverns. The natural increase in cavern oil temperature is well understood and predicted with available tools such as CAVEMAN (Ballard and Ehgartner, 2000). While not particularly problematic for storage, thermal regain is potentially problematic for oil delivery off-site in the event of an SPR drawdown. The drawdown process will eventually route the crude oil to storage tanks offsite that are held at atmospheric pressure. This warm oil may then undergo a “flash” process in which a combination of gases (CH₄, H₂S, benzene, etc.) evolves rapidly from the oil, posing acute health and safety risks in the vicinity of the storage tanks. High oil temperature exacerbates this problem, and it is therefore desirable to deliver the oil at as low a temperature as practical in order to limit emissions.

The current oil flow configuration at SPR (Figure 1-1) passes the cavern oil through a heat exchanger during a drawdown event. The cooling fluid comprises water drawn from a large nearby natural water source, for example the Intracoastal Waterway (ICW), that is at ambient temperature. Water that is passed through the heat exchanger is then routed into the cavern to act as the oil drive mechanism. Therefore, the default volumetric water flow rate is effectively the same as the oil flow rate. The SPR heat exchangers employ a standard and very effective shell-and tube configuration for allowing the cooling water and hot oil to implement heat transfer. Heat stored in the oil is conducted through the large surface area of the heat exchanger to the water. The net effect is an increase in water temperature coupled with a decrease in the oil temperature. With this configuration, the exit temperatures of the oil and water will always fall between the entry temperatures. The more efficient the heat exchanger, the closer the true log mean temperature difference approaches the theoretical counter-flow log mean temperature difference.

At SPR sites, the potential emission releases are carefully documented on a cavern-by-cavern basis for a delivery temperature of 100°F. In practice, the oils from several caverns are often blended just prior to delivery to yield a combined product with sufficiently low vapor pressure and delivery temperature so that emissions requirements are met. Geothermal heating and methane regain in the caverns complicate the problem, however, by increasing the vapor pressure of stored oils. In response, the SPR program has implemented a vapor pressure mitigation plan in which “gassy” cavern oils are passed through a degasification plant to strip out the methane and reduce the vapor pressure. The schedule for degasification is based upon observed gas regain rate and the emissions requirements at the standard delivery temperature of 100°F. Delivering the oil at a temperature of 100°F or less is therefore an important process goal.

Oil cooling during the winter and spring when the local water temperature is below 80°F is quite effective and may easily deliver the oil at temperatures well below 100°F. Water inlet temperatures exceeding 80°F during the hot summer months, along with high starting temperatures of certain oils ($T > 120^{\circ}\text{F}$) combined with a high vapor pressure poses more of a challenge and may prevent these oils from meeting delivery requirements. The driver for this work is therefore to explore the feasibility of using alternative methods to the standard configuration for oil cooling.

Figure 1-1. Schematic of heat exchanger and cavern configuration during a normal maximum rate drawdown operation. Note that drawing is not to scale and contains only the major conceptual elements of the heat exchanger system.

1.1 Objective

DOE has raised the question of whether there are feasible alternatives to cooling the oil beyond the standard practice of using only the drive water to cool oil at the time of drawdown. The proposed alternatives include:

- Cooling during degas operations
- Cooling during standby
- Cooling during a limited drawdown by increasing water flow through the heat exchanger to greater than 1:1 water:oil volume flowrate to yield a lower oil exit temperature

All of these options employ infrastructure that is already in place. Extra energy will be required to run the water and oil pumps, and run the heat exchanger for the case of standby/degas. For the case of standby/degas cooling water must also be stored and disposed of according to regulations. Additionally, some degradation of pipes, valves, etc must be expected with increased use.

The objective of this report is to examine these three potential configurations for cooling cavern oil for feasibility based on thermodynamic principles. Evaluation of associated energy needs and costs for these options are not addressed here.

2 APPROACH

Three test scenarios were examined:

- Cooling during degas operations
- Cooling during standby
- Cooling during a limited drawdown by reducing oil flow through the exchanger to yield a longer residence time and thus lower exit temperature

Each test scenario is described in detail below. Note that any engineering analysis requires assumptions, and reflects a simplification of the real system. All assumptions are outlined clearly in the approach section for each analysis. Operational considerations that may affect the feasibility of applying these test scenarios at SPR sites are addressed in the results and discussion section. No attempts were made in this report to calculate the cost of any operations under consideration.

2.1 Cooling during standby/degas

2.1.1 *Problem description*

Cooling during standby and cooling after degas are very similar in approach, and are treated here under the same heading. In this scenario, hot oil is withdrawn from the cavern, passed through the heat exchanger, and returned to the cavern at a lower temperature. This process could be applied to a cavern sitting idle, or to oil after it comes out of the degas plant before it is re-injected into the cavern.

Figure 2-1 shows a schematic of the heat exchanger and cavern configuration for cooling during a degas operation. Oil is withdrawn from the cavern using a closed loop system with no water drive—normal operating mode for a degas operation. The oil is passed through the degas plant, and before it is re-injected into the cavern, it passes through the heat exchanger. The cooling water is contained in a separate loop where it is withdrawn from the ICW or other large source, passed through the heat exchanger, and then returned to the source. In concept, this process serially removes methane and heat, both of which contribute to high vapor pressure. The schematic for cooling during standby is very similar, but there is no degas plant in the oil flow loop.

The most basic questions that this analysis addresses are (1) what is the expected temperature of the oil returned to the cavern, and (2) what is the effect of this cooling step on the temperature history of the oil in the cavern. Recall that the baseline case is no cooling after the degas operation.

Cavern oil temperature history is then predicted as a function of cooling water temperature (i.e., seasonal effects) and percentage of cavern oil cooled. The cooling should appear as a dip in the cavern oil temperature history plot, and extend the time interval between degas operations for a given cavern.

Figure 2-1. Schematic of major conceptual elements of the heat exchanger configured to cool during degas operations.

2.1.2 Applicable models

The problem was set up as two heat transfer problems in series. First, a heat exchanger model (HEATEX) was run to predict the temperature of the oil returned to the cavern, and then a thermal regain model (CaveMan) was run to predict the temperature history of the oil in the cavern.

2.1.2.1 Heat exchanger model

The heat exchangers used at SPR for cooling cavern oil during delivery are of the shell and tube type, with one shell pass and two tube passes. The energy conservation equation for the heat exchangers based on the tube outer area is given by:

$$q = U_o A_o F \Delta T_m \quad (1)$$

where q = total heat transfer [Btu/hr]

U_o = overall heat transfer coefficient based on outside tube area [Btu/hr ft² °F]

A_o = tube outside surface area [ft²]

F = log-mean temperature difference correction factor [-]

ΔT_m = log-mean temperature difference [°F]

The log-mean temperature difference is the ideal counterflow temperature difference for the whole heat exchanger. The log-mean temperature difference is based on pure countercurrent flow configuration and it needs to be corrected for the single shell and double tube passes using

the correction factor F to obtain the true mean temperature difference. For countercurrent flow the log-mean temperature difference is defined as:

$$\Delta T_m = \frac{(T_{o1} - T_{w2}) - (T_{o2} - T_{w1})}{\ln\left(\frac{T_{o1} - T_{w2}}{T_{o2} - T_{w1}}\right)} \quad (2)$$

where T_{w1} = Tube side (water) inlet temperature [$^{\circ}\text{F}$]

T_{w2} = Tube side (water) outlet temperature [$^{\circ}\text{F}$]

T_{o1} = Shell side (oil) inlet temperature [$^{\circ}\text{F}$]

T_{o2} = Shell side (oil) outlet temperature [$^{\circ}\text{F}$]

The true mean temperature difference is:

$$\Delta T_{tm} = F \Delta T_m \quad (3)$$

Values of the log-mean temperature difference correction factor F are obtained from graph or curve-fit equations. The overall heat transfer coefficient based on the tube outer area is given by:

$$U_o = \frac{1}{\frac{A_o}{A_i h_i} + \frac{A_o \ln(r_o / r_i)}{2\pi k L} + \frac{1}{h_o}} \quad (4)$$

where A_i = tube inside surface area [ft^2]

r_i = tube inner radius [ft]

r_o = tube outer radius [ft]

L = tube length [ft]

h_i = tube side film heat transfer coefficient [Btu/ hr ft^2 $^{\circ}\text{F}$]

h_o = shell side film heat transfer coefficient [Btu/ hr ft^2 $^{\circ}\text{F}$]

k = thermal conductivity of tube material [Btu/hr ft $^{\circ}\text{F}$]

The geometry parameters A_i , A_o , r_i , r_o , L , and the material property k can be obtained for the specific heat exchanger used. The tube side and shell side heat transfer coefficients are estimated using empirical correlations found in heat transfer literature. For tube side heat transfer coefficient determination correlations developed for convective heat transfer through tubes and ducts have been used. A correlation for the dimensionless heat transfer coefficient, Nusselt number (Nu_D), through a long duct that takes fluid property variations into account was proposed by Sieder and Tate (1936) as reported in Holman (1986). This correlation applies to turbulent flow and has been used for this study and is given as:

$$Nu_D = 0.027 Re_D^{0.8} Pr^{0.33} \left(\frac{\mu_b}{\mu_s} \right)^{0.14} \quad (5)$$

where Re_D = Reynolds number for flow through a duct [-]

Pr = Prandtl number for flow through a duct [-]

μ_b = dynamic viscosity at average bulk temperature [lbm/ sec ft]

μ_s = dynamic viscosity at wall temperature [Btu/ hr ft² °F]

All other fluid properties in Equation 5 are evaluated at the average bulk temperature. For laminar flow in tubes and ducts the correlation suggested by Sieder and Tate (1936) is:

$$Nu_D = 1.86 Re_D^{0.33} Pr^{0.33} \left(\frac{d_i}{L} \right) \left(\frac{\mu_b}{\mu_s} \right)^{0.14} \quad (6)$$

where d_i = tube inside diameter [ft]

The tube side heat transfer coefficient is then obtained from:

$$h_i = \frac{Nu_D k}{d_i} \quad (7)$$

To evaluate the shell side heat transfer coefficient correlations developed for flow across tube banks are used. Grimson (1937) studied various configurations of heat exchangers and provided the following correlation for the shell side Nusselt number.

$$Nu_s = C Re^n Pr^{1/3} \quad (8)$$

The values of the constants C and n for the shell and tube configuration used in the SPR heat exchangers are 0.35 and 0.6, respectively. Evaluation of the Reynolds number for shell side flow requires consideration of the shell side flow geometry.

Once the shell side Nusselt number is determined the shell side heat transfer coefficient is then obtained from:

$$h_o = \frac{Nu_s k}{d_o} \quad (9)$$

where d_o = tube outside diameter [ft]

Heat transfer as a result of water flow through the tubes is calculated from the equation:

$$q_w = m_w C_{pw} (T_{w2} - T_{w1}) \quad (10)$$

where: q_w = water side total energy [Btu/hr]

m_w = mass flowrate of water [lbm/hr]

C_{pw} = specific heat of water at the log mean temperature [Btu/lbm-°F]

Likewise, the heat transfer as a result of oil flow through the shell is calculated from the equation:

$$q_o = m_o C_{po} (T_{o1} - T_{o2}) \quad (11)$$

where the subscript “o” is used for the oil terms

For specified inlet temperatures, oil API Gravity, and oil and water flowrates the model is used to predict oil and water outlet temperatures iteratively to balance Equations 1, 10, and 11.

2.1.2.2 Cavern thermal regain model

The software CaveMan Version 4.0 (Ballard and Ehgartner, 2000) was used to study the temperature history of oil in the cavern following cooling during degas or at standby. The software is designed to provide information on daily cavern conditions that includes fluid movements in and out of the cavern, salt creep and pressure and temperature changes in the cavern. The software contains a thermal model that is used to predict temperatures in the cavern and the surrounding salt. The thermal model consists of two heat conduction submodels, one for the oil and one for the brine. Each submodel is a one dimensional, radial, finite element heat conduction model and predicts temperatures as a function of time and radial distance from cavern wall. Each submodel solves the heat conduction equation:

$$\frac{\partial T}{\partial t} = \frac{k}{\rho c} \left(\frac{\partial^2 T}{\partial r^2} + \frac{1}{r} \frac{\partial T}{\partial r} \right), \quad r_o < r < r_\infty \quad (12)$$

where T = temperature

t = time

k = thermal conductivity of salt

c = specific heat of salt

ρ = density of salt

r_o = cavern radius

r_∞ = radius in the salt where temperature is assumed constant

CaveMan also simulates heat transfer across the oil/brine interface. Further details on the submodels and implementation of Equation 12 can be found in Ballard and Ehgartner (2000).

2.1.3 Heat exchanger problem setup

The Heat Exchanger Model for the case of oil cooling after degas was designed to predict oil outlet temperatures for specified oil and water inlet temperatures and flowrates. A calculation routine HEATEX that includes the technical details described in Section 2.1.2.1 was set-up to evaluate oil outlet temperatures to be used in the Thermal Regain Model. Details on HEATEX are provided by Levin (2004). The routine uses the following input parameters:

- Heat exchanger design and geometry provided by Struthers Industries, Inc. (1995)
- Oil API gravity
- Water properties (specific gravity, viscosity, specific heat, and conductivity) as a function of temperature
- Oil properties (same as above) as a function of API 60/60°F Gravity and temperature
- Thermal conductivity of heat exchanger tube material
- Oil and water flowrates

The routine then uses the input parameters along with initially estimated bulk oil outlet, water outlet, and log mean water temperatures to compute the log mean temperature difference, LMTD correction factor, true LMTD, bulk log mean oil temperature, and heat transfer coefficients to solve the heat transfer equations 1, 10, and 11 in Section 2.1.2.1. The program iterates to find the bulk outlet oil and water and log mean water and oil temperatures where the mass flow heat transfer and overall heat transfer coefficient equations balance.

Big Hill Cavern 102 was selected as a test cavern for this modeling exercise. This cavern was selected because it is due for degasification in winter 2006/2007 (see APPENDIX D), and a winter cooling exercise should yield the maximum cooling effect possible with the current heat exchangers. The specific dates for degasification of BH102 are 11/26/06 to 04/22/07.

In order to obtain cooling water intake temperatures for the heat exchanger model, the proposed degas period was divided into three parts. The first part covers the winter months of December, January and February where the average monthly temperatures are similar. The other two parts are the months of March and April. The corresponding average water temperatures are given in Table 2-1. To study the effect of cooling water flowrate, water flowrates ranging from 90,000 bbl/day (the same as the oil flowrate) to 250,000 bbl/day were selected. The water flowrate and temperature input to HEATEX are summarized in Table 2-1. HEATEX was then run for each water flowrate and each average inlet water temperature. The results are discussed in Section 3.1.

Table 2-1. Heat Exchanger Model calculation input for the case of cooling after a degas operation in Cavern BH102

Degas Processing Period	Average Inlet cooling water temperature [°F] ¹	Cooling water flowrate [bbl/day]
11/26/06-2/28/07	54	90
March 2007	62	90
April 2007	69	90
11/26/06-2/28/07	54	130
March 2007	62	130
April 2007	69	130
11/26/06-2/28/07	54	180
March 2007	62	180
April 2007	69	180
11/26/06-2/28/07	54	250
March 2007	62	250
April 2007	69	250

2.1.4 CAVEMAN model setup

The purpose of running the thermal regain model in CaveMan here is to predict cavern oil temperatures as a function of time after oil is degassed, cooled, and reinjected. This flow configuration is shown in Figure 2-1. Recall that this problem is actually approached as two heat transfer problems in series. First, the oil is cooled in the heat exchanger (section 2.1.3) as simulated by HEATEX, and then the oil outlet temperature from HEATEX is fed into the cavern oil thermal regain model in CAVEMAN.

Assumptions:

1. The flowrate of oil withdrawn during degas/standby is the same as the flowrate that is reinjected into the cavern. i.e. No loss or gain of oil.
2. The oil inlet temperature to the heat exchanger is constant throughout the degas/cooling operation. This assumes a “plug flow” movement of the processed oil front within the cavern, and has the effect of maximizing the heat transfer potential in the heat exchanger.

¹ Water temperature data represent average Gulf Coast surface water temperatures. Data provided by DynMcDermott Petroleum Operations Company.

3. Oil inlet to the heat exchanger was identical to the starting cavern oil temperature. No heat gains or losses were allowed in transit from the cavern to the cooler. The same assumption was made for the reinjected oil.

2.1.4.1 CaveMan inputs

The CaveMan code Version 4.0 (Ballard and Ehgartner, 2000) was used for the calculation. The proposed Baseline Schedule Summaries (APPENDIX D) provides processing information including drawdown rate and time. To utilize this information and to make model predictions in line with the degas schedule, cooling during degas has been selected. Cooling during standby would produce the same results as cooling during degas and therefore is represented by these calculations. For the calculations, Cavern BH102 at the Big Hill SPR site has been selected. The cavern, which has a proposed degas time of about two years, was selected in part to provide ample time to allow possible schedule and operational changes. The cavern was also selected because the proposed degas schedule is in the winter and early spring which would provide the maximum cooling potential. The proposed degas information for this cavern is given below.

Proposed Degas Information for Cavern BH102:

Processing Rate	90,000 bbl/day
Processing Time	148 days
Start date	11/26/2006
Stop Date	04/22/2007

The CaveMan code was run to provide an average predicted cavern oil temperature for the degas period of 11/26/2006 to 04/22/2007. The calculated value is $T = 103.4^{\circ}\text{F}$. This temperature was used as oil inlet temperature along with the oil drawdown rate of 90,000 bbl/day in HEATEX.

The following is a summary of all the required inputs to the CaveMan code for the Thermal Regain Model calculations. Values of the specific inputs used for Cavern Big Hill BH102 are listed in APPENDIX E.

- Cavern geometry
- Material and thermal properties of oil, brine and salt.
- The heat transfer coefficient that regulates the heat transfer across the oil/brine interface in Cavern BH102
- The initial temperature of the salt surrounding the cavern
- The time, duration and temperature of cavern leaching
- A complete history of fluid transfers into and out of the cavern, including the volume and date of all fluids extracted from the cavern and the volume, date, and temperature of all fluids injected into the cavern.

The output of the Heat Exchanger Model in the form of heat exchanger oil outlet temperature was used as input to the Thermal Regain Model. Cooled oil temperatures for the different cases shown in Table 2.1 were utilized as input to the CaveMan code. For each case the cooled oil temperatures corresponding to the periods of Nov. 26/2006 to Feb. 28/2007, March/2007 and April/2007 were added to the “Transfers” workbook of CaveMan for Cavern BH102, together with the drawdown rate of 90,000 bbl/day. The “Transfers” input contains history of the daily transfers (in/out) of oil in a particular cavern. All other inputs for the cavern were left as before. CaveMan was then run by specifying computation start date, end date, computation time increment, and time unit in the CaveMan Temperature Worksheet workbook.

2.2 Cooling during a limited drawdown

While the SPR is obligated to maintain the capability to deliver at a stipulated maximum drawdown rate for each site, delivery rates are often much lower, with small transfers of several million barrels occurring regularly. In this more common scenario, it is possible to operate the heat exchangers in a mode where the oil volume flow rate is less than the cooling water flow rate. Some of the cooling water is sent to the cavern in order to drive the oil out, while the rest is diverted and sent to disposal. Figure 2.2 shows the major conceptual elements of this configuration. This is similar to maximum drawdown configuration, except that the water flow is split after coming out of the heat exchanger.

Figure 2-2. Schematic of major conceptual elements of the heat exchanger configured to cool during limited drawdown operation.

2.2.1 Applicable models

For this scenario, only the heat exchanger model is required. The analysis seeks the oil delivery temperature as a function of oil flowrate, oil inlet temperature, cooling water flowrate, and cooling water inlet temperature.

2.2.2 Problem setup

The problem setup started around selecting an SPR cavern with hot, gassy oil that may require extra cooling, especially in summer, to meet off-site transport and storage requirements at atmospheric pressure. A cursory review of the SPR Drawdown and Distribution Configuration Chart Rev 89 (3rd Qtr. FY04) shows that Bryan Mound and West Hackberry exhibit the highest average oil temperatures, with typical cavern readings exceeding 110 °F. Next, the caverns were screened for high bubble point pressure at 100°F. At least half of the caverns at each Bryan Mound and West Hackberry exhibited bubble points greater than 14.7 psia. From here, several cavern oils were then simulated with the Sandia Solver equilibrium vapor pressure calculator to determine the temperature sensitivity of the bubble point pressure. Of most interest for this problem is an oil that exhibits a vapor pressure above 1 atm and gas-oil ratio² (GOR) > 0.6 scf/BBL at $T \cong 100^\circ\text{F}$, but is sensitive enough to temperature lowering that the bubble point pressure and GOR fall into a safe range as T is lowered a few degrees. Bryan Mound Cavern 108 (BM108) was found to meet all these criteria. Table 2-2 shows the reported oil properties as well as simulated bubble point pressure and GOR calculated with the

Table 2-2. Oil properties for Bryan Mound Cavern 108

Reported Oil Properties for Bryan Mound cavern 108		
Source: SPR Drawdown and Distribution Configuration Chart, Rev 89 (3 rd QTR. FY04).		
Oil temperature	123°F	
Bubble point pressure	17.1 psia	
Average API gravity	33.3	
Max drawdown rate	112,000 barrels/day	
Simulated oil properties vs. Temperature from for Bryan Mound Cavern 108³		
T (F)	BPP (psia)	GOR (scf/BBL)
90	15.9	0.59
95	16.7	1.21
100	17.6	2.12
105	18.6	3.41

² GOR is defined as the volume (cubic feet) of gas evolved from one barrel of oil at equilibrium under atmospheric pressure and temperature = 100°F.

³ Input values to the Sandia Solver were obtained from the TVP-95 apparatus on the test date 02/23/2004. The data are listed in Case 3 Validation Results.

Sandia Solver for BM108. The bubble point pressure and GOR are shown for four selected temperatures from 90°F to 105°F. Note that the bubble point pressure is predicted to exceed 14.7 psia at all selected temperatures. Hence, for this oil, the GOR will be nonzero, and must remain below 0.6 scf/BBL to meet delivery requirements. Delivery at 100°F would exceed this GOR requirement with a predicted GOR of 2.12 scf/BBL. Cooling to 90°F would bring the predicted GOR to within compliance at GOR = 0.59 scf/BBL. While some safety factor would be appropriate in practice, the exercise demonstrates that cooling the oil 5 to 10 degrees below the standard 100°F may turn a currently undeliverable oil into a deliverable oil. The underlying purpose of this feasibility study is to determine the sensitivity of the oil deliverability to cooling techniques.

2.2.2.1 Assumptions

The following assumptions were made for this modeling exercise:

- Oil inlet to the heat exchanger was identical to the average cavern oil temperature. No heat gains or losses were allowed in transit from the cavern to the cooler.
- Heat exchanger performance meets manufacturer performance data. No corrosion, fouling or related loss of efficiency is considered.

2.2.2.2 Test matrix

The set of model runs was designed to encompass the likely range of input conditions to the oil coolers for a limited drawdown of the single Cavern 108. Flow boundaries on the oil were determined by looking up the maximum drawdown rate from Table 2.1, and incorporating a minimum flow rate of 75,000 barrels per day. Flow rates for the cooling water were varied from a minimum 1:1 volume ratio with respect to the oil flow rate to a maximum 250,000 barrels per day per the design specification for the heat exchanger. Oil inlet temperature was fixed at 123°F according to cavern data. Water inlet temperature was explored for three temperatures of 55, 70, and 85°F, which represent the approximate minimum, mean, and maximum seasonal water temperatures for the Texas coastal waters.

2.3 Model validation

2.3.1 Heat Exchanger Model

The Heat Exchanger Model was validated using the HTRI calculations (see APPENDIX A). Results of test runs on the HTRI calculations (Appendix A) were compared to results of the Heat Exchanger Model, HEATEX. Both calculations used the same heat exchanger specifications. Four test cases were selected for the comparison. For Case 1, oil and water inlet and outlet temperatures, and oil and water flowrates were assumed to be known, and heat transfer coefficients were calculated. For Cases 2 through 4 the same input parameters as for Case 1 were used, with the exception of water inlet temperatures. For these cases water inlet temperatures were varied and oil and water outlet temperatures were computed using the two codes. Input and results for Cases 2 and 3 are shown in Table 2-3 and Table 2-4, respectively. For Case 2 the water inlet temperature was 55 °F. The results show that for Case 2 the

HEATEX calculated oil and water outlet temperatures are within one degree of the HTRI values. The calculated true log-mean temperature difference and heat transfer coefficients of the two codes are also similar. HEATEX computes lower values for corrected log-mean temperature difference and h_i but higher values for h_o and U_o . For Case 3 the water inlet temperature was 70 °F. Similarly for Case 3, HEATEX predicted oil and water outlet temperatures that are within one degree of the HTRI values. The predicted true log-mean temperature difference and heat transfer coefficients of the two codes are also similar. HEATEX predicts lower values for true log-mean temperature difference and h_i but higher values for h_o and U_o . The HTRI calculations use more heat exchanger details than those of HEATEX. In the HTRI the heat exchanger is subdivided into subsections for calculation purposes. HEATEX calculates the heat exchanger as a single piece. Also, the oil API gravity and fluid property correlations used in the HTRI calculations could be different from those used in the HEATEX calculations. The observed differences in results could be attributed to these differences. Overall, the results are comparable. The calculations described above assumed use of carbon steel tubes. The fourth columns of Table 2-3 and 2-4 show HEATEX calculation results for the case of using Seacure® stainless steel tubes instead of the carbon steel tubes. As shown in both tables, the calculation results for Seacure® stainless steel tubes are comparable to those of the carbon steel tubes. Thus, the analysis described in Section 3 would also be applicable to Seacure® tubes.

Table 2-3. Case 2 validation inputs and results.

Winter Case 2	HTRI	HEATEX	HEATEX
Program Operator	DM	SNL	SNL
Tube Material	Carbon Steel	Carbon Steel	Seacure® Stainless
Oil flowrate [MB/day]	229.86	229.86	229.86
Water flowrate [MB/day]	230.80	230.80	230.8
API gravity	Not reported	34.0	34.0
Oil inlet temperature [°F]	120.00	120.00	120.00
Water inlet temperature [°F]	55.00	55.00	55.00
Oil outlet temperature [°F]	75.98	75.56	75.94
Water outlet temperature [°F]	71.65	72.22	72.10
Predicted corrected log-mean temperature difference [°F] ($F \times \Delta T_m$)	29.60	27.64	28.08
Predicted tube side heat transfer coefficient, h_i [Btu/ hr ft ² °F]	1759.91	1552.01	1209.27
Predicted shell side heat transfer coefficient, h_o [Btu/ hr ft ² °F]	242.85	277.94	279.58
Predicted overall heat transfer coefficient, U_o [Btu/ hr ft ² °F]	196.03	211.69	206.86

Table 2-4. Case 3 validation inputs and results

Spring Case 3	HTRI	HEATEX	HEATEX
Program Operator	DM	SNL	SNL
Tube Material	Carbon Steel	Carbon Steel	Seacure® Stainless
Oil flowrate [MB/day]	229.86	229.86	229.86
Water flowrate [MB/day]	230.80	230.80	230.80
API gravity	Not reported	34.0	34.0
Oil inlet temperature [°F]	120.00	120.00	120.00
Water inlet temperature [°F]	70.00	70.00	70.00
Predicted oil outlet temperature [°F]	86.03	85.46	85.73
Predicted water outlet temperature [°F]	82.85	83.50	83.42
Predicted corrected log-mean temperature difference [°F] ($F \times \Delta T_m$)	22.70	20.72	21.04
Predicted tube side heat transfer coefficient, h_i [Btu/ hr ft ² °F]	1759.91	1685.19	1313.00
Predicted shell side heat transfer coefficient, h_o [Btu/ hr ft ² °F]	242.16	288.47	290.51
Predicted overall heat transfer coefficient, U_o [Btu/ hr ft ² °F]	195.58	220.89	216.12

2.4 Computing platform and operating system

Both the heat exchanger model HEATEX (Levin, 2004) and the cavern thermal regain model in CAVEMAN (Ballard and Ehgartner, 2000) were run on Dell personal computers running Microsoft Office EXCEL 2003 on the Microsoft Windows XP 2003 operating system.

3 RESULTS AND DISCUSSION

3.1 Cooling during standby/degas

Problem set-up and inputs for the cooling during standby/degas scenario are discussed in Sections 2.1.3 and 2.1.4 respectively. The calculations represent Cavern BH102 for the period covering the proposed degas of the cavern. The Heat Exchanger Model (HEATEX) was first run with the proper oil and water flowrates and input temperatures. The outlet oil temperatures for the various cases given in Table 2-1 together with the degas oil processing rate of 90,000 bbl/day were then used as input to the thermal regain model (CaveMan). The results of the two models are discussed below.

3.1.1 Results from heat exchanger model

As discussed in Section 2.1.3 the proposed degas schedule was subdivided into three periods to obtain approximate average cooling water temperatures corresponding to winter (Nov–Feb), early spring (March), and middle spring (April) cooling. These three water inlet temperatures, given in Table 2.1, together with the degas oil flowrate of 90,000 bbl/day and the predicted average oil inlet temperature of 103.4°F, and the cavern average API gravity of 34.9 were used as input to the Heat Exchanger Model (HEATEX). In addition, four cooling water flowrates (Table 2.1) were selected as input to the model.

The results of HEATEX are shown in Figure 3-1, where oil outlet temperature is given as a function of cooling water flowrate. The three curves in Figure 3-1 correspond to the three cooling water temperatures described previously. Four water flowrates were run at each water inlet temperature, indicated by the symbols, and a smooth curve was fit to the data for illustration. The figure illustrates that the oil outlet temperature depends on both water inlet temperature and water flowrate. The curve representing the period Nov- Feb has the lowest oil outlet temperatures because the average water inlet temperature for this period is the lowest. Lower heat exchanger water inlet temperatures result in lower oil and water outlet temperatures. As the average water inlet temperatures increase in the months of March and April, the outlet oil temperatures also increase. While the average water inlet temperature increases by 15°F between December and April, the corresponding oil outlet temperature increases about 12°F. This indicates that water inlet temperature has a strong influence on oil outlet temperature and thus operating of the heat exchanger in the winter months would be beneficial if the maximum cooling potential is sought. Figure 3-1 also shows the effect of cooling water flowrate on oil outlet temperature. Increasing the water flowrate from 90,000 bbl/day to 250,000 bbl/day results in lowering the oil outlet temperature by 4.6 to 5.5°F for the three temperature periods considered. Given that the oil temperature drop through the heat exchangers is 25 to 45 °F, the gains in cooling capacity from increasing water flowrate are limited. For example the decrease in oil outlet temperature between the flowrates of 180,000 bbl/day and 250,000 bbl/day is 0.9 to 1.3 °F.

Figure 3-1. Oil temperature at the heat exchanger outlet versus cooling water flowrate for winter, early spring, and middle spring cooling.

3.1.2 Results from thermal regain model

The heat exchanger oil outlet temperatures plotted above in Figure 3-1 were then used as input to the CaveMan thermal regain model. Figure 3-2 through Figure 3-10 show CaveMan predictions of cavern oil and brine temperatures as a function of time for each cooling water flowrate with cavern cooling and no cooling cases shown. The no cooling case represents current CaveMan cavern temperature predictions for BH102 if the cavern was left undisturbed. The general feature of all curves indicate that the undisturbed cavern fluid temperatures increase with time asymptotically toward a value near 120°F. This reflects the salt dome temperature that ranges from 107°F at the top of the cavern to 133°F at the bottom of the cavern.

The temperature history curves show the effect of oil cooling from (i) real oil transfers around years 2000-2002, marked by the 3-4°F dips in oil temperature, and (ii) the simulated cooling exercise starting in 2006 that reduces the oil temperature by nearly 20°F. The oil transfers reduce average cavern oil temperature because the oil typically comes in from an above ground storage container at ambient air temperature. The simulated cooling exercise, annotated with an arrow on Figure 3-2, decreases the average cavern oil temperature from 104°F to 86°F during the degas/cooling period. Temperature then recovers asymptotically toward 120°F or so, but from a new start temperature near 85°F in April, 2007. For the no cooling case, the oil temperature reaches 110°F in April, 2018. For the cooling case, the oil temperature reaches

110°F in January, 2027. Thus, the model results predict that the proposed cooling exercise may effectively rewind the temperature history about 9 years for this cavern. Note that the brine temperature (Figure 3-3) also decreases as the cooled oil is returned because heat from the brine is transferred to the cooler oil. After thermal stabilization between the oil and brine, both fluid temperatures increase in parallel.

The effects of increasing cooling water flow rate through the heat exchanger are shown across the family of curves in Figure 3-2 through Figure 3-10. Generally, there is only a small return in oil cooling for the extra water flow (recall Figure 3-1), and a negligible difference in cavern thermal regain history. These results are summarized in Figure 3-10, where all of the water flowrate cases are overlaid on one curve plot. The curves representing the different flowrates seem to lie very close to each other, particularly for the higher flowrates. As was found in HEATEX, the effect of increased cooling water flow on predicted cavern oil temperature is small.

Figure 3-2. Predictions of cavern oil temperature for BH102. Cooling water flowrate = 90,000 bbl/day.

Figure 3-3. Predictions of cavern brine temperature for BH102. Cooling water flowrate = 90,000 bbl/day

Figure 3-4. Predictions of cavern oil temperature for BH102. Cooling water flowrate = 130,000 bbl/day.

Figure 3-5. Predictions of cavern brine temperature for BH102. Cooling water flowrate = 130,000 bbl/day.

Figure 3-6. Predictions of cavern oil temperature for BH102. Cooling water flowrate = 180,000 bbl/day.

Figure 3-7. Predictions of cavern brine temperature for BH102. Cooling water flowrate = 180,000 bbl/day.

Figure 3-8. Predictions of cavern oil temperature for BH 102. Cooling water flowrate = 250,000 bbl/day.

Figure 3-9. Predictions of cavern brine temperature for BH 102. Cooling water flowrate = 250,000 bbl/day.

Figure 3-10. Predictions of cavern oil temperature for BH 102 with varied cooling water flowrate.

3.1.3 Discussion of cooling during standby/degas

The CaveMan analysis documented in the series of figures above indicates that reinjection of cooled degasified oil during degas operations would lower the bulk cavern temperature for an extended period of time. Figure 3-1 shows that for this exercise the extent of the oil temperature lowering depends on two variables: the heat exchanger cooling water inlet temperature and the corresponding flowrate. To quantify the magnitude of the relative influence of each of these variables on the heat exchanger oil outlet temperature, a statistical correlation analysis was carried out using the data plotted in Figure 3-1. For the analysis the commonly used Pearson correlation coefficient was used. The coefficient measures the strength of the linear relationship between two correlated variables, in this case between oil outlet temperature and water inlet temperature or between oil outlet temperature and water flowrate. The coefficient can take on the values from -1.00 to 1.00 . Where -1.00 is a perfect negative (inverse) correlation, 0.00 is no correlation, and 1.0 is a perfect positive correlation. The calculated Pearson correlation (linear) coefficient analysis gave a correlation between water flowrate and oil outlet temperature of -0.34 , and a correlation between water inlet temperature and oil outlet temperature of 0.93 . The negative value indicates that the relationship is inverse: as the water flowrate increases the oil outlet temperature decreases. The coefficient of determination (R^2), which measures the amount of variation in the dependent variable (oil outlet temperature) was 0.98 . R^2 indicates how good the fit between the dependent and independent variables is, and has a maximum value of 1.00 . Other correlation methods also gave the same results as those of the Pearson coefficient. The correlation results indicate that the inlet water temperature has a strong influence on the outlet oil temperature while the influence of the water flowrate is about $1/3^{\text{rd}}$ of that of the inlet water temperature.

3.2 Cooling during a limited drawdown

The BM108 oil delivery temperature and flowrates for the cooling during a limited drawdown are shown graphically in Figure 3-11 and in tabular form in APPENDIX C. The analyses are subdivided into three cooling water temperatures of 85 , 70 , and 55°F .

3.2.1 Summer cooling at $T_w = 85^{\circ}\text{F}$

The most challenging oil cooling conditions occur in the summer when the cooling water intake temperature nears 85°F . The top three curves in Figure 3-11 correspond to the summer condition. Each curve represents a constant oil delivery rate designated in the figure legend. Following the curve from left to right illustrates the effect of increasing the cooling water flow rate on oil delivery temperature. For example, for a $125,000$ barrel/day oil delivery rate (top curve), an equivalent cooling water flow rate would yield oil at 95°F . Increasing the cooling water flow rate to $250,000$ barrels/day would yield oil at about 92°F . Similarly, delivering oil at $100,000$ barrels/day with equivalent water flow rate would yield oil at 94°F , while increasing the water flow rate would decrease the oil temperature to 90°F . In all cases, this hot cavern oil at a temperature of 123°F may be delivered at a temperature less than 100°F due to the high efficiency of the heat exchangers. At issue is the cooling potential of operating at the higher water flow rates. Note that the minimum oil temperature may never fall below the water inlet temperature. This is a constraint of the first law of thermodynamics. Hence, when the cooling

water intake is 85°F, the cooled oil temperature can approach, but will never reach or fall below 85°F.

In each case, some decrease in oil temperature is observed with increasing the water flow rate, but the marginal differences of just several degrees cooling suggest that the extra pumping costs and cooling water disposal issues may well offset any gains.

3.2.2 Spring and Fall cooling at $T_w = 70^\circ\text{F}$

Moderate water temperatures will cool the oil very effectively into the range between 75 and 85°F, as demonstrated in the middle set of curves in Figure 3-11. Increasing the water flow rate can bring the oil temperature to lower values in this range, but there is little operational value in this extra effort because most SPR oils meet emissions requirements at temperatures below 90°F.

Figure 3-11. Summary plot of oil outlet temperature versus cooling water flow rate for BM108 test case as predicted by HEATEX. Oil inlet $T = 123^\circ\text{F}$.

3.2.3 Winter cooling at $T_w = 55^\circ\text{F}$

Cold water temperatures in winter put the oil delivery temperature well into the safe range for emissions, as shown by the lower set of curves in Figure 3-11. Increasing cooling water flow rate will decrease oil delivery temperature, but there is likely no operational value in this at the already low oil temperatures.

3.2.4 Discussion of cooling during a limited drawdown

Increasing the water flow rate through the SPR oil coolers will, in principle, reduce oil delivery temperature relative to a 1:1 volume flow rate. It was shown in the above calculations, however, that the cooling capacity of the SPR heat exchangers is only marginally increased with considerable increases in water flowrate. For example, in the case of summer cooling BM108 oil during a limited drawdown, doubling the water flowrate is predicted to yield only a 3°F decrease in oil temperature.

Recall that the benefit of cooling oil for delivery is that the bubble point pressure may be reduced in parallel with temperature in order to prevent problematic emissions. The thermodynamic predictions in Table 2-2 indicate that cooling the BM108 oil to below 90°F is necessary to bring emissions in line with requirements. The data for summer cooling in Figure 3-11 indicate that only water flowrates exceeding 175,000 bbl/day, coupled with a low process oil flowrate of 75,000 bbl/day, may deliver oil cooler than 90°F. In this case with a water flow rate of 250,000 bbl/day, the oil is only 1°F below the calculated maximum safe delivery temperature, which leaves a very small safety factor. Hence, the system would be pushed to operating at its limits of maximum water flow, low process oil flow, and minimum safety factor. This does not appear to be a preferred option when an alternative such as oil blending is available to meet emissions-driven safety requirements, though it may be considered under severe circumstances.

There are other technologies available to cool oil, most or all of which use a vapor-compression refrigeration cycle. Such systems are ubiquitous in modern homes, businesses, and vehicles. From the perspective of the authors of this report, these technologies appear prohibitively expensive for application at the SPR sites when the combined strategies of water cooling, degasification, and blending streams can meet current oil delivery requirements for a limited drawdown. Note that the scope of this feasibility report does not include an analysis of the additional power needs or costs associated with additional cooling or warm water disposal. These elements would have to be investigated in order to make any precise statements about the likely additional cost of cooling.

4 CONCLUSIONS

4.1 Cooling during standby/degas

Two heat transfer models, HEATEX and CaveMan, were run in series to simulate the process of cooling an SPR crude oil after degasification and injecting it back into the cavern. The example cavern Big Hill 102 was chosen for this simulation because it is due for degas in winter 2006/2007 when the cooling effect should be maximized.

The following conclusions were drawn from the model results:

- Winter cooling of the degas stream resulted in a 20°F decrease in cavern oil temperature.
- After the degas+cooling cycle, the cavern required about 9 years in an undisturbed state to return to the oil temperature at the start of degas.
- This approach may have some potential benefit for combating the negative effects of thermal regain on deliverability of the hot, gassy cavern oils in a major summertime drawdown scenario.
- These data examine only one cavern and do not examine costs. A broader, sitewide feasibility study that includes a cost-benefit analysis would be required before such a cooling operation is recommended.

4.2 Cooling during a limited drawdown

The heat exchanger model HEATEX was used to predict the delivery temperatures for Bryan Mound Cavern 108 oil during a limited drawdown scenario. The cooling water flowrate through the heat exchanger was varied from one to approximately three times the oil flowrate at three water inlet temperatures of 55°F, 70°F, and 85°F.

The following conclusions were drawn from the model results:

- The inherent efficiency of the SPR heat exchangers in the normal operating mode of 1:1 oil:water volume flowrate appears to be very effective at cooling hot oil to a delivery temperature below 100°F, even during summer months.
- The study demonstrates with a selected example that pumping extra cooling water through a heat exchanger during a limited drawdown in the summer will yield only very small decreases in oil temperature (~3°F) relative to the normal operating mode.
- Oils that present emissions problems are not likely to be mitigated by extra cooling afforded by increasing the cooling water flowrate.
- There may be selected caverns (i.e. BM 108) where extra cooling alone can bring the oil to within delivery requirements, though this is recommended as a backup plan under severe circumstance rather than a primary mitigation strategy.
- A limited drawdown scenario allows the opportunity to selectively blend oils to meet safe emissions requirements, and extra cooling is not needed.

5 RECOMMENDATIONS FOR FUTURE WORK

Among the oil cooling alternatives examined here, the most promising approach appears to be cooling of cavern oil during degasification or during standby. This study examined just one cavern as an example. A cursory review of the cavern temperature and bubble point data indicate that nearly half of the SPR caverns exhibit sufficiently high temperature and bubble point (evaluated at 100°F) that cooling upon delivery during an extended full-rate summer drawdown may be problematic. All of these hot, gassy caverns would be candidates for this type of analysis.

Sandia therefore recommends that the DOE consider executing a modeling study that examines the cooling during degas/standby scenario for all of the hot, gassy SPR caverns. This action would give a site-wide perspective on the potential benefits of the cooling operation. The results of the proposed study could then be input for a cost/benefit analysis that contains a full examination of operating costs, wear and tear on equipment, environmental impacts and permitting requirements, etc. to determine the detailed costs and potential benefits in terms of site readiness for a large-scale drawdown.

6 REFERENCES

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APPENDIX A: VALIDATION HTRI SHEETS

The following validation data were provided by Stephen Brothers of DynMcDermott Petroleum Operations Company.

Case 2 Validation Results

Output Summary						Page 1
Released to the following HTRI Member Company:						
DOE						
SPR						
Xist Ver. 2.00 11/8/2004 13:53 SN: 1500209618						US Units
BIG HILL CRUDE OIL COOLERS						
DESIGN DATA , YUBA HEAT TRANSFER						
Simulation-Horizontal Multipass Flow TEMA AEU Shell with NTIW-Segmental Baffles						
No data check messages.						
See runtime report for warning messages.						
Process Conditions		Hot Shell		Cold Tube		
Flow rate	(1000-lb/hr)		2803.96		3357.95	
Inlet/Outlet Y	(Wt. frac vap.)	0.000	0.000	0.000	0.000	
Inlet/Outlet T	(Deg F)	120.00	75.98	55.00	71.65	
Inlet P/Avg	(psia)	614.700	594.506	614.700	608.542	
dP/Allow.	(psi)	40.388	51.000	12.317	28.000	
Fouling	(ft2-hr-F/Btu)		0.00000		0.00000	
Exchanger Performance						
Shell h	(Btu/ft2-hr-F)	242.16	Actual U	(Btu/ft2-hr-F)	195.58	
Tube h	(Btu/ft2-hr-F)	1759.91	Required U	(Btu/ft2-hr-F)	197.57	
Hot regime	(--)	Sens. Liquid	Duty	(MM Btu/hr)	55.9100	
Cold regime	(--)	Sens. Liquid	Area	(ft2)	9561.99	
EMTD	(Deg F)	29.6	Overdesign	(%)	-1.01	
Shell Geometry			Baffle Geometry			
TEMA type	(--)	AEU	Baffle type	(--)	NTIW-Seg.	
Shell ID	(inch)	60.0000	Baffle cut	(Pct Dia.)	14.60	
Series	(--)	1	Baffle orientation	(--)	Perpend.	
Parallel	(--)	1	Central spacing	(inch)	13.5000	
Orientation	(deg)	0.00	Crosspasses	(--)	17	
Tube Geometry			Nozzles			
Tube type	(--)	Plain	Shell inlet	(inch)	19.2500	
Tube OD	(inch)	0.7500	Shell outlet	(inch)	19.2500	
Length	(ft)	24.000	Inlet height	(inch)	9.0000	
Pitch ratio	(--)	1.3333	Outlet height	(inch)	9.5000	
Layout	(deg)	90	Tube inlet	(inch)	19.2500	
Tubecount	(--)	2104	Tube outlet	(inch)	19.2500	
Tubepasses	(--)	2				
Thermal Resistance, %		Velocities, ft/sec		Flow Fractions		
Shell	80.77	Shellside	4.80	A	0.353	
Tube	14.27	Tubeside	7.64	B	0.398	
Fouling	0.00	Crossflow	10.36	C	0.019	
Metal	4.963	Window	8.20	E	0.230	
				F	0.000	

Final Results					Page 3
Released to the following HTRI Member Company:					
DOE					
SPR					
Xist Ver. 2.00 11/8/2004 13:53 SN: 1500209618				US Units	
BIG HILL CRUDE OIL COOLERS					
DESIGN DATA , YUBA HEAT TRANSFER					
Simulation-Horizontal Multipass Flow TEMA AEU Shell with NTIW-Segmental Baffles					
Process Data		Hot Shellside		Cold Tubeside	
Fluid name		CRUDE OIL		RAW WATER	
Fluid condition		Sens. Liquid		Sens. Liquid	
Total flow rate	(1000-lb/hr)	2803.96		3357.95	
Weight fraction vapor, In/Out	(--)	0.000	0.000	0.000	
Temperature, In/Out	(Deg F)	120.00	75.98	55.00	
Temperature, Average/Skin	(Deg F)	98.0	69.70	63.3	
Wall temperature, Min/Max	(Deg F)	63.11	78.41	61.22	
Pressure, In/Average	(psia)	614.700	594.506	614.700	
Pressure drop, Total/Allowed	(psi)	40.388	51.000	12.317	
Velocity, Mid/Max allow	(ft/sec)	4.80		7.64	
Mole fraction inert		(--)			
Average film coef.	(Btu/ft2-hr-F)	242.16		1759.91	
Heat transfer safety factor	(--)	1.000		1.000	
Fouling resistance	(ft2-hr-F/Btu)	0.00000		0.00000	
Overall Performance Data					
Overall coef., Req'd/Clean/Actual	(Btu/ft2-hr-F)	197.57	/	195.58 / 195.58	
Heat duty, Calculated/Specified	(MM Btu/hr)	55.9100	/		
Effective overall temperature difference	(Deg F)	29.6			
EMTD = (MTD) * (DELTA) * (F/G/H)	(Deg F)	30.59	*	0.9676 * 1.0000	
See Runtime Messages Report for warnings.
Exchanger Fluid Volumes					
Approximate shellside	(ft3)	292.256			
Approximate tubeside	(ft3)	321.435			
Shell Construction Information					
TEMA shell type	AEU	Shell ID	(inch)	60.0000	
Shells Series	1 Parallel 1	Total area	(ft2)	9915.36	
Passes Shell	1 Tube 2	Eff. area	(ft2/shell)	9561.99	
Shell orientation angle (deg)	0.00				
Impingement present	Circular plate	Impingement diameter/nozzle	1.1		
Pairs seal strips	0	F-stream seal rods (inch)	0.0000	No. 0	
Shell expansion joint	No	Full baffle at U-bend	Yes		
Weight estimation Wet/Dry/Bundle	139405 /	101118 /	42537 (lb/shell)		
Baffle Information					
Type	Perpend. NTIW-Seg.	Baffle cut (pct dia)	14.60		
Crosspasses/shellpass	17	No. (Pct Area)	(inch) to C.L		
Central spacing	(inch) 13.5000	1	13.47	21.2400	
Inlet spacing	(inch) 46.5000	2	0.00	0.0000	
Outlet spacing	(inch) 25.6250				
Baffle thickness	(inch) 0.3750				
Tube Information					
Tube type	Plain	Tubecount per shell	2104		
Length to tangent	(ft) 24.000	Pct tubes removed (both)	17.54		
Effective length	(ft) 23.146	Outside diameter	(inch)	0.7500	
Total tubesheet	(inch) 10.2500	Wall thickness	(inch)	0.0830	
Area ratio	(out/in) 1.2842	Pitch (inch)	1.0000	Ratio 1.3333	
Tube metal	Carbon steel	Tube pattern	(deg)	90	

Final Results					Page 4
Released to the following HTRI Member Company:					
DOE					
SPR					
Xist Ver. 2.00 11/8/2004 13:53 SN: 1500209618					US Units
BIG HILL CRUDE OIL COOLERS					
DESIGN DATA , YUBA HEAT TRANSFER					
Simulation-Horizontal Multipass Flow TEMA AEU Shell with NTIW-Segmental Baffles					
Shellside Performance					
Nom vel, X-flow/window		10.36 / 8.20			
#REF!		#REF!			
Flow fractions for heat transfer		0.517			
A=0.3526	B=0.3976	C=0.0194	E=0.2304	F=0.0000	
Shellside Heat Transfer Corrections					
Total	Beta	Gamma	End	Fin	
0.986	0.920	1.072	0.852	1.000	
Pressure Drops (Percent of Total)					
Cross	Window	Ends	Nozzle	Shell	Tube
86.71	7.28	3.99	Inlet	1.09	3.29
MOMENTUM		0.00	Outlet	0.93	2.09
Two-Phase Parameters					
Method	Inlet	Center	Outlet	Mix F	
#REF!				#REF!	
#REF!					
H. T. Parameters			Shell	Tube	
Overall wall correction			1.000	1.000	
Midpoint	Prandtl no.		108.44	5.04	
Midpoint	Reynolds no.		4366	46339	
Bundle inlet	Reynolds no.		1242	46320	
Bundle outlet	Reynolds no.		2269	46320	
Fouling layer	(inch)				
Thermal Resistance					
Shell	Tube	Fouling	Metal	Over Des	
80.77	14.27	0.00	4.963	-1.01	
Total fouling resistance				0.00000	
Differential resistance				-5.15E-05	
Shell Nozzles					
Inlet at channel end-Yes			Inlet	Outlet	Liquid Outlet
Number at each position			1	1	0
Diameter		(inch)	19.2500	19.2500	
Velocity		(ft/sec)	7.30	7.15	
Pressure drop		(psi)	0.440	0.376	
Height under nozzle		(inch)	9.0000	9.5000	
Nozzle R-V-SQ		(lb/ft-sec2)	2814.20	2754.49	
Shell ent.		(lb/ft-sec2)	968.65	650.14	
Tube Nozzle (RADIAL)					
Diameter		(inch)	19.2500	19.2500	Liquid Outlet
Velocity		(ft/sec)	7.39	7.41	
Pressure drop		(psi)	0.405	0.258	
Nozzle R-V-SQ		(lb/ft-sec2)	3409.24	3419.87	
Annular Distributor					
Length		(inch)	#REF!	#REF!	
Height		(inch)	#REF!	#REF!	
Slot area		(in2)	#REF!	#REF!	
Diametral Clearances (inch)					
Baffle-to-shell		Bundle-to-shell		Tube-to-baffle	
0.3125		0.8113		0.0313	

Supplementary Results				Page 5
Released to the following HTRI Member Company: DOE SPR				
Xist Ver. 2.00 11/8/2004 13:53 SN: 1500209618				US Units
BIG HILL CRUDE OIL COOLERS DESIGN DATA , YUBA HEAT TRANSFER Simulation-Horizontal Multipass Flow TEMA AEU Shell with NTIW-Segmental Baffles				
Externally Enhanced Tube Geometry			Internally Enhanced Tube Geometry	
Type	Plain		Type	Plain
Fin density	(fin/inch)		Thickness	(inch)
Fin height	(inch)		Pitch	(L/D)
Fin thickness	(inch)			
Root diameter	(inch)			
Area/length	(ft2/ft)			
Mean Metal Temperatures				
Mean shell temperature		95.93 (F)		
Mean tube metal temperature in each tubepass, (F)				
<u>Tubepass</u>	<u>Inside</u>	<u>Outside</u>	<u>Radial</u>	
1	64.86	66.54	65.77	
2	71.33	72.68	72.06	

Case 3 Validation Results

Output Summary					Page 1
Released to the following HTRI Member Company:					
DOE					
SPR					
Xist Ver. 2.00 11/8/2004 13:54 SN: 1500209618					US Units
BIG HILL CRUDE OIL COOLERS					
DESIGN DATA , YUBA HEAT TRANSFER					
Simulation-Horizontal Multipass Flow TEMA AEU Shell with NTIW-Segmental Baffles					
No data check messages.					
See runtime report for warning messages.					
Process Conditions		Hot Shell		Cold Tube	
Flow rate	(1000-lb/hr)		2803.96		3357.95
Inlet/Outlet Y	(Wt. frac vap.)	0.000	0.000	0.000	0.000
Inlet/Outlet T	(Deg F)	120.00	86.03	70.00	82.85
Inlet P/Avg	(psia)	614.700	594.446	614.700	608.527
dP/Allow.	(psi)	40.509	51.000	12.347	28.000
Fouling	(ft2-hr-F/Btu)		0.00000		0.00000
Exchanger Performance					
Shell h	(Btu/ft2-hr-F)	242.16	Actual U	(Btu/ft2-hr-F)	195.58
Tube h	(Btu/ft2-hr-F)	1759.91	Required U	(Btu/ft2-hr-F)	199.18
Hot regime	(--)	Sens. Liquid	Duty	(MM Btu/hr)	43.1502
Cold regime	(--)	Sens. Liquid	Area	(ft2)	9561.99
EMTD	(Deg F)	22.7	Overdesign	(%)	-1.81
Shell Geometry			Baffle Geometry		
TEMA type	(--)	AEU	Baffle type	(--)	NTIW-Seg.
Shell ID	(inch)	60.0000	Baffle cut	(Pct Dia.)	14.60
Series	(--)	1	Baffle orientation	(--)	Perpend.
Parallel	(--)	1	Central spacing	(inch)	13.5000
Orientation	(deg)	0.00	Crosspasses	(--)	17
Tube Geometry			Nozzles		
Tube type	(--)	Plain	Shell inlet	(inch)	19.2500
Tube OD	(inch)	0.7500	Shell outlet	(inch)	19.2500
Length	(ft)	24.000	Inlet height	(inch)	9.0000
Pitch ratio	(--)	1.3333	Outlet height	(inch)	9.5000
Layout	(deg)	90	Tube inlet	(inch)	19.2500
Tubecount	(--)	2104	Tube outlet	(inch)	19.2500
Tubepasses	(--)	2			
Thermal Resistance, %		Velocities, ft/sec		Flow Fractions	
Shell	80.77	Shellside	4.82	A	0.353
Tube	14.27	Tubeside	7.66	B	0.398
Fouling	0.00	Crossflow	10.39	C	0.019
Metal	4.963	Window	8.22	E	0.230
				F	0.000

Final Results						Page 3
Released to the following HTRI Member Company:						
DOE						
SPR						
Xist Ver. 2.00 11/8/2004 13:54 SN: 1500209618					US Units	
BIG HILL CRUDE OIL COOLERS						
DESIGN DATA , YUBA HEAT TRANSFER						
Simulation-Horizontal Multipass Flow TEMA AEU Shell with NTIW-Segmental Baffles						
Process Data		Hot Shellside		Cold Tubeside		
Fluid name		CRUDE OIL		RAW WATER		
Fluid condition		Sens. Liquid		Sens. Liquid		
Total flow rate	(1000-lb/hr)	2803.96		3357.95		
Weight fraction vapor, In/Out	(--)	0.000	0.000	0.000	0.000	
Temperature, In/Out	(Deg F)	120.00	86.03	70.00	82.85	
Temperature, Average/Skin	(Deg F)	103.0	81.31	76.4	80.08	
Wall temperature, Min/Max	(Deg F)	76.23	88.03	74.78	86.37	
Pressure, In/Average	(psia)	614.700	594.446	614.700	608.527	
Pressure drop, Total/Allowed	(psi)	40.509	51.000	12.347	28.000	
Velocity, Mid/Max allow	(ft/sec)	4.82		7.66		
Mole fraction inert	(--)					
Average film coef.	(Btu/ft2-hr-F)	242.16		1759.91		
Heat transfer safety factor	(--)	1.000		1.000		
Fouling resistance	(ft2-hr-F/Btu)	0.00000		0.00000		
Overall Performance Data						
Overall coef., Req'd/Clean/Actual	(Btu/ft2-hr-F)	199.18	/	195.58	/ 195.58	
Heat duty, Calculated/Specified	(MM Btu/hr)	43.1502	/			
Effective overall temperature difference	(Deg F)	22.7				
EMTD = (MTD) * (DELTA) * (F/G/H)	(Deg F)	23.43	*	0.9671	* 1.0000	
See Runtime Messages Report for warnings.
Exchanger Fluid Volumes						
Approximate shellside	(ft3)	292.256				
Approximate tubeside	(ft3)	321.435				
Shell Construction Information						
TEMA shell type	AEU	Shell ID	(inch)	60.0000		
Shells Series	1 Parallel 1	Total area	(ft2)	9915.36		
Passes Shell	1 Tube 2	Eff. area	(ft2/shell)	9561.99		
Shell orientation angle (deg)	0.00					
Impingement present	Circular plate	Impingement diameter/nozzle	1.1			
Pairs seal strips	0	F-stream seal rods (inch)	0.0000	No.	0	
Shell expansion joint	No	Full baffle at U-bend	Yes			
Weight estimation Wet/Dry/Bundle	139405 /	101118 /	42537	(lb/shell)		
Baffle Information						
Type	Perpend. NTIW-Seg.	Baffle cut (pct dia)	14.60			
Crosspasses/shellpass	17	No. (Pct Area)	(inch) to C.L			
Central spacing	(inch) 13.5000	1	13.47	21.2400		
Inlet spacing	(inch) 46.5000	2	0.00	0.0000		
Outlet spacing	(inch) 25.6250					
Baffle thickness	(inch) 0.3750					
Tube Information						
Tube type	Plain	Tubecount per shell	2104			
Length to tangent	(ft) 24.000	Pct tubes removed (both)	17.54			
Effective length	(ft) 23.146	Outside diameter	(inch)	0.7500		
Total tubesheet	(inch) 10.2500	Wall thickness	(inch)	0.0830		
Area ratio	(out/in) 1.2842	Pitch (inch)	1.0000	Ratio	1.3333	
Tube metal	Carbon steel	Tube pattern	(deg)	90		

Final Results					Page 4
Released to the following HTRI Member Company:					
DOE					
SPR					
Xist Ver. 2.00 11/8/2004 13:54 SN: 1500209618					US Units
BIG HILL CRUDE OIL COOLERS					
DESIGN DATA , YUBA HEAT TRANSFER					
Simulation-Horizontal Multipass Flow TEMA AEU Shell with NTIW-Segmental Baffles					
Shellside Performance					
Nom vel, X-flow/window		10.39 / 8.22			
Flow fractions for heat transfer		0.517			
A=0.3526 B=0.3976		C=0.0194		E=0.2304 F=0.0000	
Shellside Heat Transfer Corrections					
Total	Beta	Gamma	End	Fin	
0.986	0.920	1.072	0.852	1.000	
Pressure Drops (Percent of Total)					
Cross	Window	Ends	Nozzle	Shell	Tube
86.71	7.28	3.99	Inlet	1.09	3.29
MOMENTUM		0.00	Outlet	0.93	2.10
Two-Phase Parameters					
Method	Inlet	Center	Outlet	Mix F	
H. T. Parameters			Shell	Tube	
Overall wall correction			1.000	1.000	
Midpoint	Prandtl no.		108.44	5.04	
Midpoint	Reynolds no.		4366	46339	
Bundle inlet	Reynolds no.		1242	46320	
Bundle outlet	Reynolds no.		2269	46320	
Fouling layer	(inch)				
Thermal Resistance					
Shell	Tube	Fouling	Metal	Over Des	
80.77	14.27	0.00	4.963	-1.81	
Total fouling resistance				0.00000	
Differential resistance				-9.24E-05	
Shell Nozzles					
Inlet at channel end-Yes			Inlet	Outlet	Liquid Outlet
Number at each position			1	1	0
Diameter		(inch)	19.2500	19.2500	
Velocity		(ft/sec)	7.30	7.18	
Pressure drop		(psi)	0.440	0.378	
Height under nozzle		(inch)	9.0000	9.5000	
Nozzle R-V-SQ		(lb/ft-sec2)	2814.20	2767.89	
Shell ent.		(lb/ft-sec2)	968.65	653.31	
Tube Nozzle (RADIAL)					
			Inlet	Outlet	Liquid Outlet
Diameter		(inch)	19.2500	19.2500	
Velocity		(ft/sec)	7.41	7.43	
Pressure drop		(psi)	0.406	0.259	
Nozzle R-V-SQ		(lb/ft-sec2)	3418.82	3427.06	
Annular Distributor					
			Inlet	Outlet	
Length		(inch)			
Height		(inch)			
Slot area		(in2)			
Diametral Clearances (inch)					
Baffle-to-shell		Bundle-to-shell		Tube-to-baffle	
0.3125		0.8113		0.0313	

Supplementary Results				Page 5
Released to the following HTRI Member Company: DOE SPR				
Xist Ver. 2.00 11/8/2004 13:54 SN: 1500209618				US Units
BIG HILL CRUDE OIL COOLERS DESIGN DATA , YUBA HEAT TRANSFER Simulation-Horizontal Multipass Flow TEMA AEU Shell with NTIW-Segmental Baffles				
Externally Enhanced Tube Geometry			Internally Enhanced Tube Geometry	
Type	Plain		Type	Plain
Fin density	(fin/inch)		Thickness	(inch)
Fin height	(inch)		Pitch	(L/D)
Fin thickness	(inch)			
Root diameter	(inch)			
Area/length	(ft2/ft)			
Mean Metal Temperatures				
Mean shell temperature	101.41 (F)			
Mean tube metal temperature in each tubepass, (F)				
<u>Tubepass</u>	<u>Inside</u>	<u>Outside</u>	<u>Radial</u>	
1	77.59	78.87	78.28	
2	82.57	83.61	83.14	

APPENDIX B: BH108 COMPOSITIONAL DATA

The following data were obtained from the TVP-95 test of BH108 cavern oil on 02/23/2004, listed in the EXCEL database worksheet "Bryan Mound 040815.xls". These data were used as the input to the Sandia Solver to derive the simulated BPP and GOR values for BM108 listed in Table 2-2.

Date	02/23/04	
Cavern	bm108	
ie, bh102 or in		
T(F)	100	
Measured Pressure (psia)	17.7	
Measured GOR	0	
(SCF/BBL)		
	vapor	
	composition	
	(% mole)	
Nitrogen	7.382	
Carbon Monoxide	0.000	
Carbon Dioxide	2.479	
Argon	0.302	
Oxygen	0.000	
Hydrogen Sulfide	0.963	
Methane	18.240	
Ethane	13.371	
Propane	21.800	
Iso-Butane	5.115	
N-Butane	14.110	
Iso-Pentane	4.592	
N-Pentane	5.569	
N-Hexane	4.356	
Heptanes	0.991	
Benzene	0.084	
Toluene	0.104	
Ethyl Benzene	0.016	
Xylenes	0.047	
Residual	0.479	
Sum	100.00	
Cavern	Specific	Molecular
BH108	Gravity	Weight
	0.861366667	213.7333333

APPENDIX C: TABULAR HEATEX MODEL OUTPUT FOR BM108 LIMITED DRAWDOWN TESTS.

Cavern	Scenario/Criteria	API	Flow Rates				Fluid Temperatures (°F)							Heat Transfer Coefficients			
		Gravity	MB/D		GPM		Criteria Inlet		Computed TrueLMTs		TLMTD	Computed Outlet		h_i	U_{tube}	h_o	U_{HX}
		60/60°F	Oil	Water	Oil	Water	Oil	Water	Oil	Water	Oil-Water	Oil	Water	Btu/hr ft ² °F	Btu/hr ft ² °F	Btu/hr ft ² °F	Btu/hr ft ² °F
Design 2	HEATEX Carbon Steel $U_o = 211.69$	34.0	229.86	230.80	6704.39	6731.71	120.0	55.0	90.93	63.29	27.64	75.56	72.22	1552.01	3351.29	277.94	211.69
Design 2	HEATEX Seacure® $U_o = 206.86$	34.0	229.86	230.80	6704.39	6731.71	120.0	55.0	92.12	64.04	28.08	75.94	72.10	1209.27	2965.10	279.58	206.86
Case 2	11/8/2004 DM HTRI $U_o = 196.03$	Not Rprtd	229.86	230.80	6704.39	6731.71	120.0	55.0			29.60	75.98	71.65	1759.91		242.85	196.03
Design 3	HEATEX Carbon Steel $U_o = 220.89$	34.0	229.86	230.80	6704.39	6731.71	120.0	70.0	96.72	76.00	20.72	85.46	83.50	1685.19	3351.29	288.47	220.89
Design 3	HEATEX Seacure® $U_o = 216.12$	34.0	229.86	230.80	6704.39	6731.71	120.0	70.0	98.06	77.02	21.04	85.73	83.42	1313.00	2965.10	290.51	216.12
Case 3	11/8/2004 DM HTRI $U_o = 195.58$	Not Rprtd	229.86	230.80	6704.39	6731.71	120.0	70.0			22.70	86.03	82.85	1759.91		242.16	195.58
BH102	Output & True Log Mean Temps and Heat Transfer Coefficients for variable water entering temps and flows for 90 MB/D Oil flow at 103.4F entering oil temperature	34.9	90.00	90.00	2625.00	2625.00	103.4	54.0	78.06	62.00	16.06	66.14	68.37	716.99	3351.29	157.58	118.55
		34.9	90.00	90.00	2625.00	2625.00	103.4	62.0	83.95	70.80	13.15	72.05	74.17	762.35	3351.29	161.77	122.48
		34.9	90.00	90.00	2625.00	2625.00	103.4	69.0	86.78	76.00	10.78	78.92	79.17	787.99	3351.29	164.27	124.75
		34.9	90.00	130.00	2625.00	3791.67	103.4	54.0	75.87	59.50	16.37	63.61	64.59	940.08	3351.29	156.12	123.92
		34.9	90.00	130.00	2625.00	3791.67	103.4	62.0	80.00	66.50	13.50	69.95	70.95	989.10	3351.29	159.03	126.83
		34.9	90.00	130.00	2625.00	3791.67	103.4	69.0	84.03	72.98	11.05	75.53	76.50	1033.90	3351.29	162.14	129.74
	Dec, Jan, Feb ave water inlet temp	34.9	90.00	180.00	2625.00	5250.00	103.4	54.0	74.45	57.94	16.51	61.90	61.96	1200.87	3351.29	155.21	128.03
	Mar average water inlet temp	34.9	90.00	180.00	2625.00	5250.00	103.4	62.0	79.10	65.49	13.61	68.51	68.74	1270.65	3351.29	158.34	131.15
	Apr average water inlet temp	34.9	90.00	180.00	2625.00	5250.00	103.4	69.0	83.14	72.00	11.14	74.32	74.64	1329.89	3351.29	161.41	134.06
		34.9	90.00	250.00	2625.00	7291.67	103.4	54.0	73.45	56.90	16.55	60.58	59.91	1544.47	3351.29	154.58	131.60
		34.9	90.00	250.00	2625.00	7291.67	103.4	62.0	78.17	64.50	13.66	67.40	67.00	1636.93	3351.29	157.68	134.68
		34.9	90.00	250.00	2625.00	7291.67	103.4	69.0	82.29	71.10	11.19	73.41	73.19	1716.03	3351.29	160.75	137.60
BM108	Output & True Log Mean Temps and Heat Transfer Coefficients for Variable Oil & Water Flows and entering water temperatures for 123F entering oil temperature	33.3	75.00	75.00	2187.50	2187.50	123.0	55.0	87.19	66.06	21.13	71.29	75.14	642.86	3351.29	138.66	105.18
		33.3	75.00	77.32	2187.50	2255.17	123.0	55.0	86.25	65.01	21.24	70.98	74.63	653.48	3351.29	138.07	105.19
		33.3	75.00	115.00	2187.50	3354.17	123.0	55.0	84.28	62.59	21.68	67.29	69.09	877.14	3351.29	136.56	110.07
		33.3	75.00	155.00	2187.50	4520.83	123.0	55.0	82.40	60.50	21.90	65.22	65.82	1092.02	3351.29	135.33	112.82
		33.3	75.00	200.00	2187.50	5833.33	123.0	55.0	81.48	59.51	21.98	63.81	63.58	1324.93	3351.29	134.71	115.06
		33.3	75.00	250.00	2187.50	7291.67	123.0	55.0	81.01	59.01	21.99	62.80	61.98	1574.30	3351.29	134.37	116.87
		33.3	75.00	75.00	2187.50	2187.50	123.0	70.0	93.94	78.01	15.93	82.50	85.92	693.74	3351.29	144.15	110.05
		33.3	75.00	77.32	2187.50	2255.17	123.0	70.0	93.81	77.85	15.96	82.23	85.54	709.93	3351.29	144.03	110.49
		33.3	75.00	115.00	2187.50	3354.17	123.0	70.0	93.64	77.41	16.24	79.29	81.19	969.40	3351.29	143.57	116.44
		33.3	75.00	155.00	2187.50	4520.83	123.0	70.0	90.97	74.50	16.48	77.68	78.58	1204.68	3351.29	141.56	118.65
		33.3	75.00	200.00	2187.50	5833.33	123.0	70.0	90.80	74.28	16.52	76.56	76.81	1472.52	3351.29	141.32	121.26
		33.3	75.00	250.00	2187.50	7291.67	123.0	70.0	89.35	72.75	16.60	75.80	75.53	1739.58	3351.29	140.29	122.48

Cavern	Scenario/Criteria	AP	Flow Rates				Fluid Temperatures (°F)						Heat Transfer Coefficients				
		Gravity	MB/D		GPM		Criteria Inlet		Computed TrueLMTs		TLMTD	Computed Outlet		h _i	U _{tube}	h _o	U _{HX}
		60/60°F	Oil	Water	Oil	Water	Oil	Water	Oil	Water	Oil-Water	Oil	Water	Btu/hr ft² °F	Btu/hr ft² °F	Btu/hr ft² °F	Btu/hr ft² °F
BM108 (Cont.)	Output & True Log Mean Temps	33.3	75.00	75.00	2187.50	2187.50	123.0	85.0	101.99	91.01	10.98	93.81	96.59	746.62	3351.29	151.38	115.95
	and Heat Transfer Coefficients for	33.3	75.00	77.32	2187.50	2255.17	123.0	85.0	101.76	90.75	11.01	93.62	96.31	763.85	3351.29	151.18	116.36
	Variable Oil & Water Flows and	33.3	75.00	115.00	2187.50	3354.17	123.0	85.0	100.36	89.10	11.26	91.50	93.14	1037.60	3351.29	149.83	121.80
	entering water temperatures for	33.3	75.00	155.00	2187.50	4520.83	123.0	85.0	99.52	88.15	11.37	90.31	91.26	1308.56	3351.29	149.03	125.16
	123F entering oil temperature	33.3	75.00	200.00	2187.50	5833.33	123.0	85.0	99.40	88.01	11.40	89.50	89.97	1601.67	3351.29	148.84	127.90
		33.3	75.00	250.00	2187.50	7291.67	123.0	85.0	98.49	87.05	11.44	88.94	89.04	1902.54	3351.29	148.07	129.42
		33.3	100.00	100.00	2916.67	2916.67	123.0	55.0	88.10	65.01	23.09	72.42	74.70	803.96	3351.29	164.76	125.54
		33.3	100.00	135.00	2916.67	3937.50	123.0	55.0	87.92	64.47	23.45	69.51	70.42	1013.82	3351.29	164.22	130.64
		33.3	100.00	170.00	2916.67	4958.33	123.0	55.0	85.16	61.35	23.81	67.79	67.59	1187.29	3351.29	162.09	132.46
		33.3	100.00	210.00	2916.67	6125.00	123.0	55.0	84.21	60.25	23.96	66.43	65.43	1390.33	3351.29	161.28	134.73
		33.3	100.00	250.00	2916.67	7291.67	123.0	55.0	83.55	59.50	24.05	65.47	63.90	1585.92	3351.29	160.73	136.43
		33.3	100.00	100.00	2916.67	2916.67	123.0	70.0	95.25	77.85	17.40	83.31	85.61	872.94	3351.29	171.77	131.73
		33.3	100.00	135.00	2916.67	3937.50	123.0	70.0	94.01	76.26	17.75	81.05	82.20	1095.58	3351.29	170.38	136.24
		33.3	100.00	170.00	2916.67	4958.33	123.0	70.0	93.00	75.05	17.95	79.64	80.00	1304.46	3351.29	169.33	139.11
		33.3	100.00	210.00	2916.67	6125.00	123.0	70.0	92.28	74.20	18.07	78.57	78.29	1533.45	3351.29	168.58	141.49
		33.3	100.00	250.00	2916.67	7291.67	123.0	70.0	91.75	73.60	18.15	77.81	77.07	1753.59	3351.29	168.04	143.23
		33.3	100.00	100.00	2916.67	2916.67	123.0	85.0	103.03	91.01	12.02	94.35	96.38	940.24	3351.29	180.33	138.70
		33.3	100.00	135.00	2916.67	3937.50	123.0	85.0	101.78	89.50	12.28	92.70	93.90	1183.41	3351.29	178.90	143.40
		33.3	100.00	170.00	2916.67	4958.33	123.0	85.0	101.39	88.99	12.40	91.67	92.31	1417.37	3351.29	178.36	146.82
		33.3	100.00	210.00	2916.67	6125.00	123.0	85.0	100.54	88.05	12.49	90.89	91.05	1667.77	3351.29	177.45	149.17
		33.3	100.00	250.00	2916.67	7291.67	123.0	85.0	100.29	87.75	12.54	90.34	90.17	1912.74	3351.29	177.13	151.16
		33.3	125.00	125.00	3645.83	3645.83	123.0	55.0	89.34	64.69	24.64	73.42	74.32	959.61	3351.29	188.76	144.21
		33.3	125.00	150.00	3645.83	4375.00	123.0	55.0	88.50	63.53	24.97	71.67	71.65	1097.90	3351.29	187.76	147.19
		33.3	125.00	180.00	3645.83	5250.00	123.0	55.0	87.40	62.15	25.25	70.15	69.26	1253.97	3351.29	186.61	149.67
		33.3	125.00	215.00	3645.83	6270.83	123.0	55.0	86.65	61.20	25.45	68.85	67.22	1431.58	3351.29	185.80	152.03
		33.3	125.00	250.00	3645.83	7291.67	123.0	55.0	86.29	60.73	25.56	67.8806	65.689	1606.29	3351.29	185.36	154.02
		33.3	125.00	125.00	3645.83	3645.83	123.0	70.0	96.34	77.75	18.59	84.04	85.33	1043.40	3351.29	196.85	151.30
		33.3	125.00	150.00	3645.83	4375.00	123.0	70.0	95.55	76.70	18.86	82.65	83.21	1197.11	3351.29	195.81	154.37
		33.3	125.00	180.00	3645.83	5250.00	123.0	70.0	95.07	76.02	19.05	81.44	81.33	1376.78	3351.29	195.11	157.32
		33.3	125.00	215.00	3645.83	6270.83	123.0	70.0	94.17	74.95	19.22	80.42	79.71	1573.40	3351.29	194.05	159.54
		33.3	125.00	250.00	3645.83	7291.67	123.0	70.0	93.81	74.49	19.32	79.66	78.50	1767.66	3351.29	193.57	161.52
		33.3	125.00	125.00	3645.83	3645.83	123.0	85.0	103.54	90.65	12.88	94.85	96.18	1122.06	3351.29	206.20	158.92
		33.3	125.00	150.00	3645.83	4375.00	123.0	85.0	103.07	90.01	13.06	93.83	94.65	1292.27	3351.29	205.49	162.38
		33.3	125.00	180.00	3645.83	5250.00	123.0	85.0	102.71	89.51	13.19	92.94	93.28	1489.63	3351.29	204.93	165.56
		33.3	125.00	215.00	3645.83	6270.83	123.0	85.0	101.83	88.51	13.32	92.20	92.10	1705.83	3351.29	203.85	167.87
		33.3	125.00	250.00	3645.83	7291.67	123.0	85.0	101.58	88.19	13.39	91.64	91.21	1919.73	3351.29	203.47	170.00

APPENDIX D: DRAFT DEGASIFICATION SCHEDULE

Draft degasification plant schedule as of 10/28/2004, provided by DynMcDermott Petroleum Operations Company.

Proposed Baseline Schedule Summaries Assumes 90% Plant Operating Availability

BH

106 AVERAGE PROCESSING RATE

1103 TOTAL OPERATING DAYS

4/15/2004 START DATE

4/22/2007 END DATE

Cavern	BH108	BH113	BH103	BH114	BH112	BH101	BH104	BH110	BH102
Processing Rate (MBD)	120	135	90	90	126	90	90	126	90
Processing Time (days)	89	81	145	144	95	146	145	110	148
Start Date	4/15/2004	7/13/2004	10/2/2004	2/24/2005	7/18/2005	10/20/2005	3/16/2006	8/8/2006	11/26/2006
Stop Date	7/13/2004	10/2/2004	2/24/2005	7/18/2005	10/20/2005	3/16/2006	8/8/2006	11/26/2006	4/22/2007

BM

108 AVERAGE PROCESSING RATE

1250 TOTAL OPERATING DAYS

1/17/2008 START DATE

6/20/2011 END DATE

Cavern	BM115	BM4	BM102	BM105	BM116	BM114	BM104	BM108	BM106	BM111
Processing Rate (MBD)	90	90	126	126	90	90	126	126	90	126
Processing Time (days)	119	257	98	94	126	100	98	101	153	105
Start Date	01/17/08	05/15/08	01/26/09	05/04/09	08/06/09	12/10/09	03/21/10	06/26/10	10/06/10	03/07/11
Stop Date	05/15/08	01/26/09	05/04/09	08/06/09	12/10/09	03/21/10	06/26/10	10/06/10	03/07/11	06/20/11

WH

104 AVERAGE PROCESSING RATE

1767 TOTAL OPERATING DAYS

12/17/2011 START DATE

10/18/2016 END DATE

Cavern	WH105	WH102	WH101	WH108	WH110	WH116	WH104	WH107	WH103	WH113	WH111	WH117	WH115	WH112	WH11	WH9
Processing Rate (MBD)	90	90	90	90	90	90	90	90	90	90	126	126	126	126	126	126
Processing Time (days)	130	120	125	122	128	127	125	131	114	127	85	102	90	94	70	77
Start Date	12/17/11	04/25/12	08/22/12	12/25/12	04/26/13	09/02/13	01/07/14	05/11/14	09/19/14	01/11/15	05/18/15	08/11/15	11/21/15	02/20/16	05/24/16	08/02/16
Stop Date	04/25/12	08/22/12	12/25/12	04/26/13	09/02/13	01/07/14	05/11/14	09/19/14	01/11/15	05/18/15	08/11/15	11/21/15	02/20/16	05/24/16	08/02/16	10/18/16

BC

114 AVERAGE PROCESSING RATE

409 TOTAL OPERATING DAYS

4/16/2017 START DATE

5/31/2018 END DATE

Cavern	BC19	BC17	BC18
Processing Rate (MBD)	126	126	90
Processing Time (days)	104	104	202
Start Date	04/16/17	07/29/17	11/10/17
Stop Date	07/29/17	11/10/17	05/31/18

APPENDIX E: BH102 CAVEMAN INPUT DATA

Required input data for Cavern BH102 obtained from CaveMan Parameters workbook of CaveMan Version 4.0.

Date: 11/15/2004	BH102
DailyData well - primary	102B/SW
DailyData well - 1st alternate	102A/SW
Daily Data well - 2nd alternate	102A/SW
Cavern Data well	102A/SW
api	33
cavtop (ft)	2300
cavbot (ft)	4087
salt temp at top of cavern (°F)	107.32
salt temp at bottom of cavern (°F)	133.23
Interface Heat Transfer Coefficient (BTU/day/ft ² /°F)	17
Oil Salt Temperature (°F)	107.32
Brine Salt Temperature (°F)	120.28
salt modulus (psi)	1.1E+06
salt structure factor (1/d)	2.04E+18
saltstress (psi)	3.64E+03
Kzero	1.04E+05
Alpha	-9.00E+00
Alphar	-3.60E+00
eta0	7.04E-04
date	3/23/1991
Erms	10.71
time1	6/24/2004
Calculated pressure at time1	912.79132
eta at time1	0.0001749

Salt Dissolution:

Magnitude Factor	1
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