# Arroyo Grande Oilfield

# San Luis Obispo County, California

# Dollie Sands, Pismo Formation

# Freeport-McMoRan Oil & Gas LLC

# Contents

## Executive Summary

**Company:** Freeport-McMoRan Oil & Gas LLC
**Field:** Arroyo Grande Oilfield
**County:** San Luis Obispo County, California
**Class and Well Type:** Class II, WD and EOR
**Formation:** Edna Member, Dollie Sands, Pismo Formation
**Exemption Justification:** §146.4 Criteria for exempted aquifers

(a) It does not currently serve as a source of drinking water

(b) It cannot now and will not in the future serve as a source of drinking water because:

(1) It is mineral, hydrocarbon or geothermal energy producing, or can be demonstrated by a permit applicant as part of a permit application for a Class II or III operation to contain minerals or hydrocarbons that considering their quantity and location are expected to be commercially producible

The Arroyo Grande oilfield is located in Price Canyon, three miles northeast of Pismo Beach in San Luis Obispo County, CA. (Section 31, Township 31 South, Range 13 East). The oilfield is unusual in that it is entirely within a syncline and hydrocarbons exist throughout the field both aerially and vertically. The first oil production in the field was from a surface mining operation that quarried 150,000 tons of tar sands between 1880 and 1922. Based on an average grade of 26 gallons of oil per ton, the 150,000 tons of quarried tar sands is equivalent to about 93,000 barrels of oil recovered. The tar sand oil-in-place reserves have been estimated to be 175 million barrels for deposits within 250 feet from surface based on studies from numerous core hole and surface samples. As shown in the groundwater testing results (App. D (1)(a)), this observation is supported by data that shows water wells inside and outside the oil field limits are naturally contaminated with hydrocarbons because of the prevalence of the tar accumulations.

Since 1919 Arroyo Grande has been a state designated oilfield with the first oil well completed in 1906. The oil averages 13 degrees API gravity and thermal enhanced oil production (EOR) began in 1978 (steam injection). The total number of wells on production at any one time was less than 25 before EOR operations began. Today there are about 260 wells in operation. To date, about 560 wells have been drilled and about 19 million barrels of oil have been produced from wells, which is a small percentage of the estimated original oil in place. Current oil production averages 1,350 barrels of oil per day (bopd) and is estimated to exceed 6,000 bopd when the field is fully developed.

Hydrocarbons are distributed throughout the oilfield reservoir, both vertically and aerially. There are only hydrocarbon-bearing sands in the oilfield. For example, cross-sections along the west side and from the west side to the center of the oilfield demonstrate this (App. A (7)(a)(3); A (7)(a)(2)). The west side cross-section shows oil saturated sands (dark green shading on the resistivity curve and sidewall cores) continuously from north to south. Likewise, the west side to central cross-section shows oil sands thickening into the center of the syncline. The pervasive nature of oil distribution is evident in a map of sidewall and whole data shown on the M-2 structure map in Appendix A (7)(a). This is reinforced in a cumulative oil production bubble map in figure 1. In addition, pre-1974 oil well completions demonstrate oil production at all levels of the reservoir that are being developed currently (App. A (7)(a)(7)).

Evidence of the extensive oil accumulation at the Arroyo Grande oilfield is available from the Division of Oil, Gas, & Geothermal Resources (DOGGR) publications for at least the past 70 years. In 1944, DOGGR published a detailed map of the extensive Pismo Formation surface tar sands within the current DOGGR administrative boundary (App. A (3-2)). In 1958, DOGGR published an Arroyo Grande Oilfield summary showing a map and cross-section depicting the distribution of tar sands and oil sands covering some of the current oilfield development area in the Tiber area (App. A (6-1)). In 1974, DOGGR published another oilfield summary, Technical Report (TR) 12, which contained a map of Arroyo Grande oilfield productive limits (App. A (6-2)). This map was the basis for establishment of the original aquifer exemption boundaries for the oil field as part of the 1983 Memorandum of Understanding (MOU) and Primacy Agreement between DOGGR and the United States Environmental Protection Agency (USEPA). In 1989 DOGGR published an updated oilfield summary (App. A(6-3)) with a map showing a large increase in the productive area of the field in the Tiber area as compared to the initial productive limit established in the 1974 TR 12. The updated productive limits depicted in the 1989 DOGGR TR 12, covers a significant portion of the expanded exemption area currently being proposed by Freeport-McMoRan Oil & Gas (FM O&G). The 1989 TR 12 also contains a modern type-log and a cross-section with stratigraphic markers that are in use today. A high level of geologic continuity exists between the current oilfield development and the 1974 and the 1989 productive area limits that can be demonstrated by maps and cross-sections. Oil production occurred outside the 1974 productive limits prior to establishment of the state/federal MOU and validates the existence of hydrocarbons in the proposed exemption application as does whole core, sidewall core, and well log data. All of the extensive oil saturation data collected across the proposed exemption area demonstrates that the Edna member Dollie sands of the Pismo Formation is oil saturated throughout, both vertically and aerially.

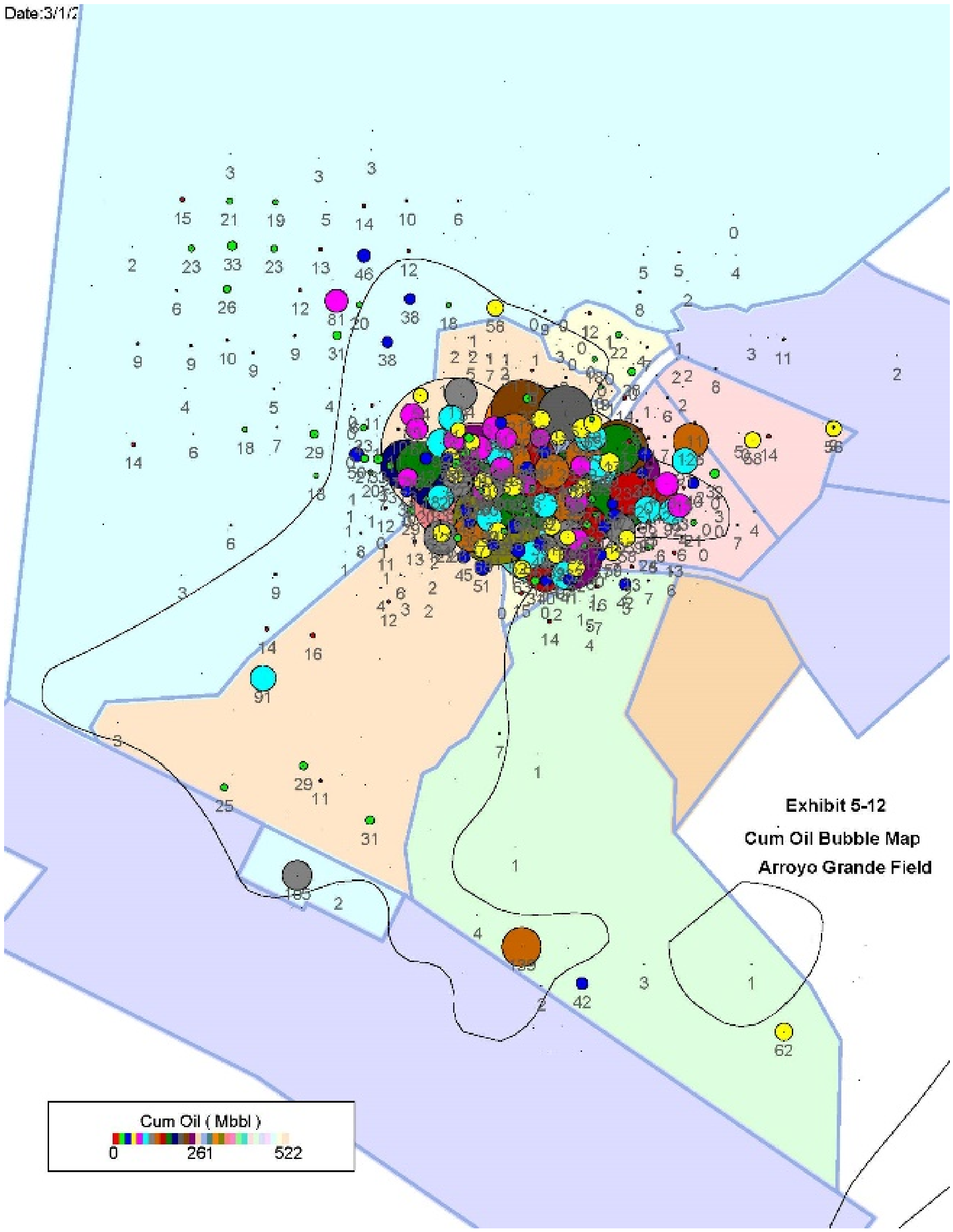

Date:3/1/2
Exhibit 5-12
Cum Oil Bubble Map
Arroyo Grande Field
Cum Oil ( Mbbl )
0
261
522

*Figure 1*

# 1. Applicant Information

## 1.1. Project/Field Name and Location

Edna Member, Dollie Sands, Pismo Formation

Arroyo Grande Field

San Luis Obispo County, California

## 1.2. Well Class and Purposes of Injection

Class II

Water Disposal and Enhanced Oil Recovery

## 1.3. Areal Extent/Dimensions of Study Area

The area requested for exemption is approximately 4,800’ wide, 7,700’ long and extends from the surface to about 1,700’ in depth.

## 1.4. Name and Address of the Applying Owner/Operator

Freeport-McMoRan Oil & Gas LLC
1200 Discovery Drive, Suite 100
Bakersfield, CA  93309

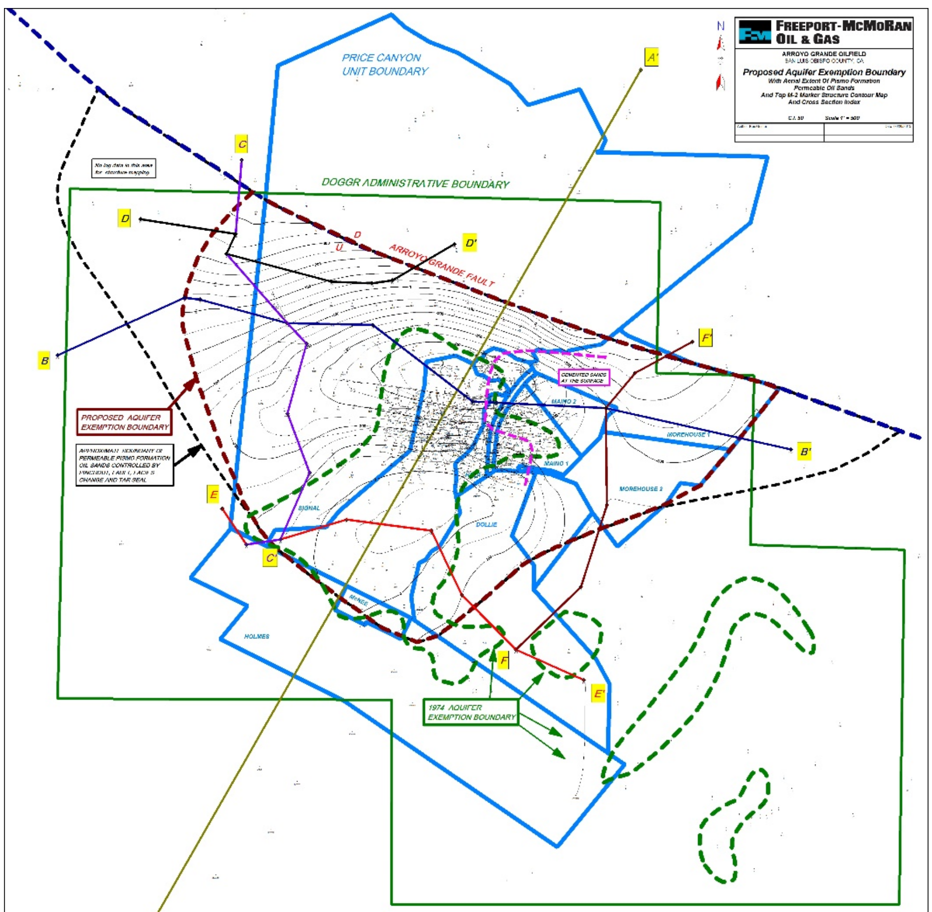



*Figure 1.1 Proposed Exemption Boundary*

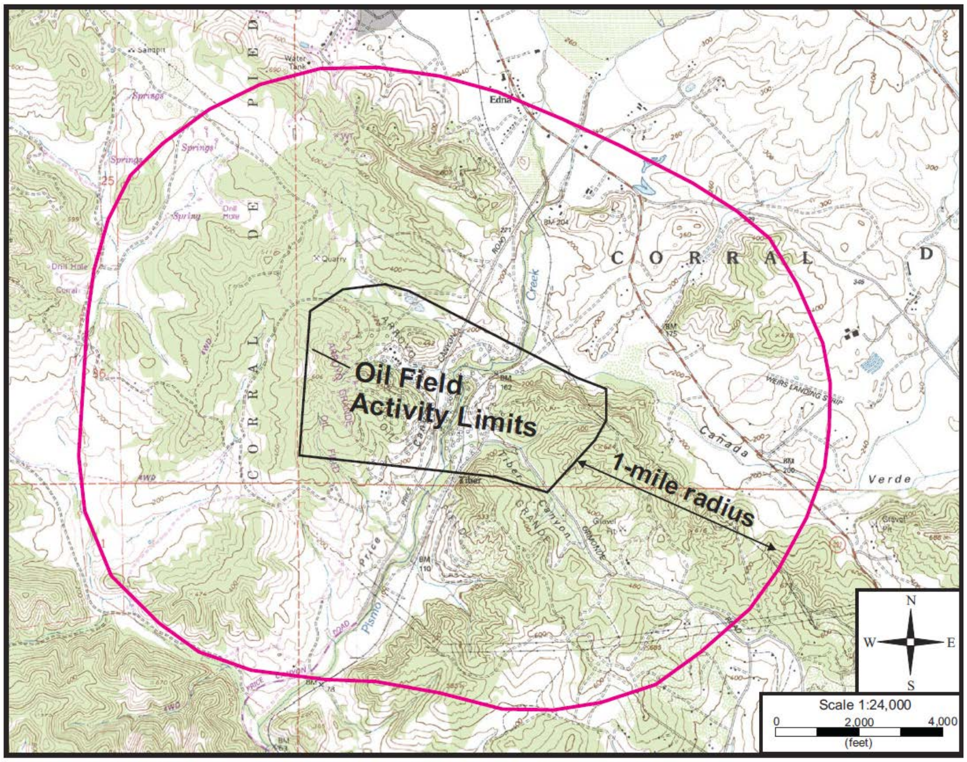



*Figure 1.2 Study Area for Water Wells*

# 2. EXEMPTION DESCRIPTIONS

## 2.1. Aquifer/Zone Name

Edna Member, Dollie sands, Pismo Formation

### 2.1.1. Depth/Thickness of Aquifer

250 feet deep, 1,450 feet thick

### 2.1.2. Lateral Extent of the Area Proposed for Exemption

4,800' wide, 7,700' long

### 2.1.3. Description of Aquifer/Zone Containment

Injected fluid containment to the north is controlled by the Arroyo Grande Fault (App. A (7)(a)(1,3,4,6)). To the south, containment is controlled by the pinch out (facies change) from the Edna Member (Dollie sand – 300 millidarcys to 2 darcys) to the low permeability Miguelito Member (1.7 millidarcys) siltstone and claystone (App. A (7)(a)(1,3,5,6)). Injected fluid containment to the west (App. A (7)(a)(2,4)) and to the east (App. A (7)(a)(2,6)) is controlled by a lateral tar seal and/or a loss in permeability. This is evidenced by the loss of oil saturation on the logs and in the core data upwards from the center of the syncline on to the east and west limbs of the fold. The oilfield's vertical containment is established by a surface tar seal and layers of silt and clay (App. I (2)) as well as cemented sandstone (Figure 2-1). FM O&G's fluid injection is a minimum of 450' from surface which further ensures the integrity of the natural seals is not being interfered with by oil field injection activities.

FM O&G's setback from the Price Canyon Unit boundary for fluid injection has also proven to be an effective safeguard to containment for oilfield operations for many decades at the Arroyo Grande

Oilfield. This setback will be incorporated into the project approval for all injection projects in the Arroyo Grande oilfield. All of FM O&G's current and future anticipated injection operations will continue to be set back from the boundaries of the modified aquifer exemption area. Since all existing and future operations are setback from the edge of the updated boundary of the exempted area, the engineered design of FM O&G's operations further ensure there is no interference with the natural features that confine migration of fluids to the oil reservoir.

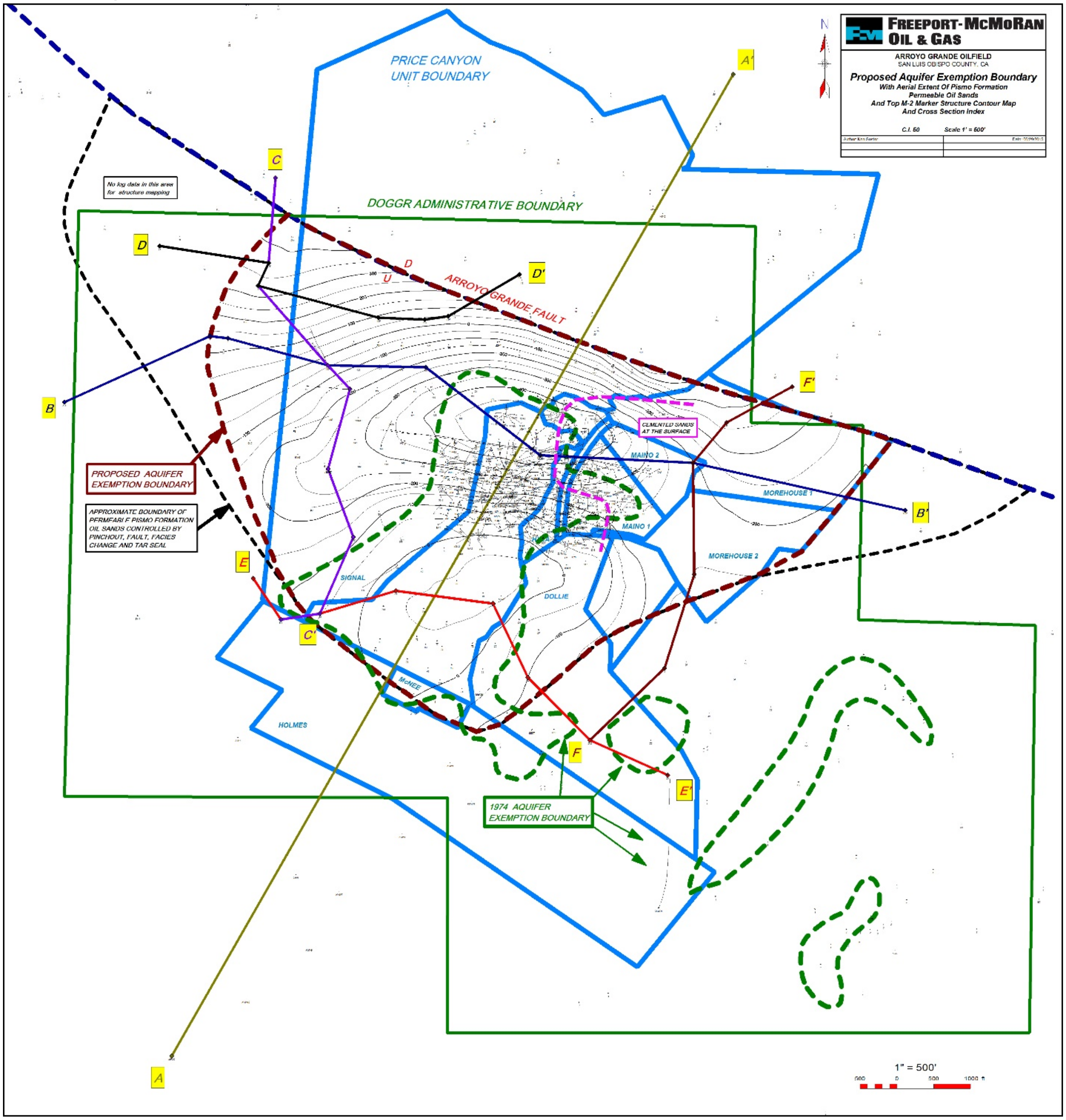



*Figure 2-1*

A review of the groundwater supply well logs located within one mile of the oil field also provide critical evidence that the oil reservoir and oilfield activity are contained within the syncline structure. There is no evidence that the injected fluids have migrated beyond the confines of the reservoir after decades of injection operations. Cleath Harris Geologists (CHG) was retained by FM O&G to conduct a review of the groundwater supply well logs within a mile of the oilfield (App. G (1-1)). CHG's report validates that most of these water wells in the region are in separate structural sub-basins, hydraulically isolated from the oilfield. None of the logs contained information, notes, or entries indicating heat from the oil field thermal operations had been encountered when the groundwater supply wells were drilled. Furthermore, the logs of the groundwater supply wells did not provide any evidence of hydrocarbon saturation on the same level as evidenced by the logs of wells drilled within the confines of the oil reservoir. These factors can be utilized to validate the effectiveness of the tar seal/low permeability/pinch out controls that inhibit fluid migration out of the oil reservoir.

Finally, recent evidence of pressure reduction in the syncline resulting from the water reclamation facility validates that injected fluids will stay contained in the oil reservoir. Additional information on this topic is contained in the hydraulic reservoir analysis of the next section.

**Hydraulic Analysis for Arroyo Grande Syncline**

The approach used in this analysis will be to present a simplified picture of the hydraulics, using a basic "u-tube" model analog, to explain the physical criteria involved (heights, liquid densities, associated pressures, etc.) and what the result would be for ideal, frictionless flow in a tube (or pipe). Then, the factors that apply more specifically to this oil reservoir will be noted and it will be pointed out how these factors combine to significantly decrease the likelihood for non-containment to occur.

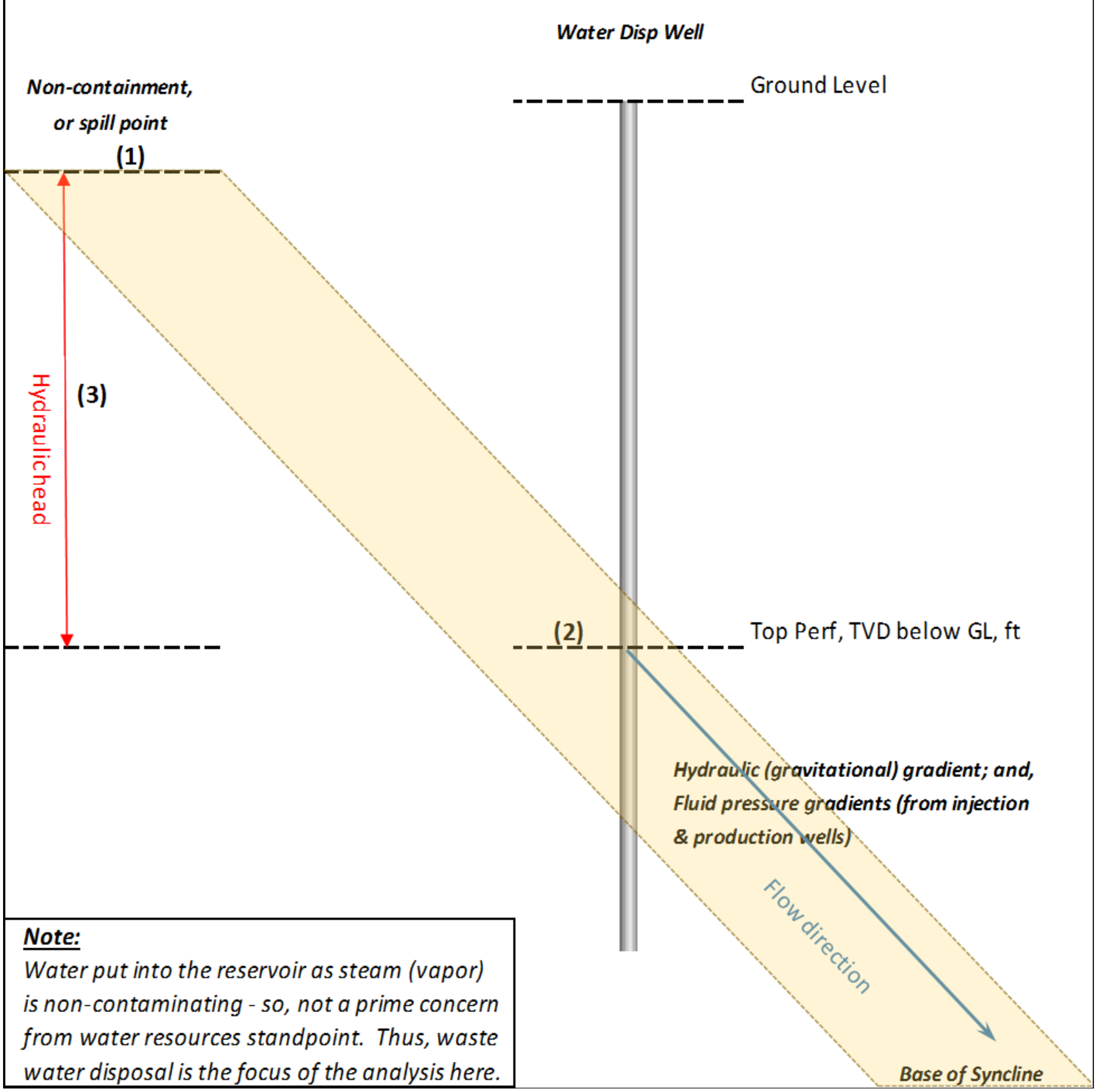
A first step in performing a hydraulic analysis at the Arroyo Grande oilfield was to establish the reference elevation for the level at which non-containment is considered to be a possibility (if all associated conditions necessary for such a case were to co-exist). This is designated by the bracketed numeral 1 in schematic diagram, Figure HA-1. To conduct the analysis from the conservative standpoint, the lowest such level (i.e., depth for loss of confinement) was selected. Referring to "conservative" will mean that it is approached from this same pro containment point-of-view. Based on our extrapolation of mapped sandstone intervals (App. A(7)(a)(2,3,4,6)), and using data for the west flank of the syncline, it is estimated that this level is at 275 ft above mean sea level (MSL). Besides having effectively the lowest depth for loss of confinement (compared to the south and east flanks), the west flank is where the majority of active water disposal wells are located.

The next step was to select representative water disposal wells from which to create the hydraulic model. Three, relatively near-by water disposal wells in this category are:

| Well | Top Perf<br>Measured Depth | Top Perf<br>True Vertical Depth | Elevation<br>Kelly Bushing |
|---|---|---|---|
| "Pulas" 6 | 596' | 559' | 418' |
| "Pulas" 7 | 550' | 538' | 369' |
| "Pulas" 8 | 460' | 455' | 421' |
| Measured Depth = Depth measured along wellbore path | | | |
| True Vertical Depth = Depth measured perpendicular to the surface | | | |
| Kelly Bushing = Reference point on drilling rig used for measuring the well, i.e. 0' in depth | | | |

Of these wells, “Pulas” 8 has the least distance to the depth for loss of confinement, so it has been selected for use as shown for the example presented in Table HA-1. This depth corresponds to the level shown by the bracketed numeral 2 in Figure HA-1. The height of the column between the top perforation and the assumed depth for loss of confinement is shown by the red line in Figure HA-1, which has been identified by the bracketed numeral 3. Again, being conservative, the density of the water column has been assumed to be 0.435 psi/ft (i.e., essentially fresh) as shown by item (4) in Table HA-1. The hydraulic head imposed by the column, item (5) in Table HA-1, is then calculated to be 134 psi.

**Figure HA-1: Schematic for Hydraulic Analysis**



The reservoir pressures used in this analysis were based on two separate, multi-well surveys of bottom-hole pressures: one was conducted in February 2013, about 2 months before the Water Reclamation Facility (WRF) came into full-time operation; and, the other was just recently done in June 2015. The wells selected for the surveys had either been shut-in for several years after previously being produced (i.e., for February 2013 survey) or had been drilled during the previous year but had not been completed (i.e., for June 2015 survey). Thus, the static pressures measured should be representative of the reservoir pressure in that part of the field where the well is located. All wells surveyed in June 2015 were completed as slim-hole dual-string steam injectors; surveys were run separately on each string, thus allowing comparison of the resulting gradients across the field and providing a means to determine if the pressures were uniform in the vertical direction (i.e., between producing layers). The average reservoir pressure gradients determined from those two surveys are shown on the item (6) line of Table HA-1. Applying those pressures to the column between ground level and the top perforation depth gives the reservoir pressures shown on the item (7) line of Table HA-1.

**Table HA-1: Hydraulic Analysis Assumptions & Results**

| *Description of Parameter or Value* | *Item* | *Feb'13* | *Jun'15* |
|---|---|---|---|
| Spill level elevation, ft above MSL | (1) | 275 | 275 |
| Highest injection point, TVD, ft below GL | (2) | 455 | 455 |
| Highest injection point, ft below MSL | | 34 | 34 |
| Vertical distance: top perf to spill level, ft | (3) | 309 | 309 |
| Max Allowed Fm Frac Press Grad, psi/ft | | 0.700 | 0.700 |
| Max inj press @ top perf, psig | (9) | 319 | 319 |
| Actual inj press @ top perf, psig | (10) | 286 | 231 |
| Effective inj press gradient, psi/ft | (11) | 0.627 | 0.507 |
| Reservoir Fluid Grad, psi/ft | (6) | 0.380 | 0.224 |
| Est Reservoir Press, psi | (7) | 173 | 102 |
| Delta Press, psi | (8) | 113 | 129 |
| Fresh water gradient , psi/ft | (4) | 0.435 | 0.435 |
| Hydraulic head from water (if filled to spill point), psi | (5) | 134 | 134 |

It is noteworthy that there has been a decrease in reservoir pressure of over 70 psi during the past 26 months. This is due to dewatering of the reservoir, with over 10 million “net” barrels of water having been removed during that same 2+ year period. This is going accordingly to plan, as the related, expected benefit on thermal-enhanced oil recovery provided the incentive to make the substantial capital investment necessary to install the WRF.

As it is both prudent operating practice and a DOGGR regulation that for injection purposes it is not permitted to inject above the fracture gradient, a general guideline at Arroyo Grande Field has been to never exceed imposing more pressure on the reservoir than the equivalent of a 0.70 psi/ft gradient (determined by a step rate test). If that "max gradient" were applied, the injection pressure at the top perf would be as shown on the item (9) line in Table HA-1. Actual field operations demonstrate that injection is below 0.7 psi/ft. This is achieved by controlling flow rate and the distribution into the disposal wells that are being used. During the February 2013 survey, with total water disposal at approximately 12,500 barrels of water per day (bwpd), the actual wellhead pressure was about 30 psig less than the maximum pressure allowed. During the June 2015 survey, the actual wellhead pressure was nearly 90 psig less than the maximum allowed – as shown by item (10) line entries in Table HA-1. At the present time, waste water disposal into the reservoir is averaging about 4,000 bwpd. The corresponding effective injection pressure gradients are, from item (11) entries, 0.63 and 0.51 psi/ft, respectively.

The reservoir pressure can be thought of as a resisting force relative to injection at a wellbore; thus, the difference between these pressures is the total head available to lift the liquid column. This difference, termed "delta press" is given on the item (8) line of Table HA-1. Since, for both cases, the available head is less than that required to lift the water column head (on item (5) line), the condition required to overflow the containment level has not been met.

The following factors, which would either decrease the head available to lift the water column or otherwise work to oppose such occurrence, have not been taken into direct consideration in the foregoing discussion:

1. The situation being dealt with here is multi-phase fluid flow in porous media, not pipe flow or single phase fluid flow. Because of this, the effective permeability to water will be lower due to the presence of oil and gas; part of the pore space will be occupied by residual oil; and, the associated pressure drop will be notably higher.

2. The effects of dewatering the reservoir will continue, and are expected to become notably more pronounced when the new Wet Electro-Static Precipitator (WESP) and gas incinerator are completed and start-up begins in late-August 2015. This will further decrease reservoir pressure, thus lowering required wellhead injection pressure to dispose of waste water. The pressure sink associated with the syncline base area in the original steam-flood portion of the field will be further emphasized, allowing gravitational gradient to be even more influential on downward migration of liquids.
    a. While fluid pressure gradients created by the individual steam patterns in the field will exist, the required steam injection pressures will continue to fall for the next 2-3 years until a new equilibrium operating pressure is reached. This activity should not influence the factors that insure containment of liquids within the reservoir.

3. New wells that are drilled in the future will produce less water than similar wells have in the past; thus, even as the WRF reaches its design capacity of 20,000 bwpd to the creek, waste water volume is not expected to increase dramatically and will be relatively small compared to withdrawals. Therefore, as long as water and gas continue to be removed from the reservoir as water is now and gas soon will be, there should be no problem with containment from the reservoir hydraulics perspective. This approach is the obvious one for FM O&G to follow as operator, since besides making focused efforts to follow all regulations and good operating

practices, it is to their economic benefit to do so and increases or maintains efficient oil production

4. While there is some interconnectivity between certain layers of the reservoir, there are also barriers (with very low/limited transmissibility) to vertical migration of fluids– based on observed differences in pressure between the upper and lower intervals (between shallower perforated intervals and deeper perforated intervals from the most recent BHP survey). This vertical isolation between the subzones would mean that injection would tend to stay within the subzone(s) that it is entering via the perforations in the injection well; accordingly, unless injection was in the uppermost interval, the level of non-containment would be higher – thus, giving more margin (or a larger safety factor) than has been assumed herein.

**Cross-section Descriptions**

Section A – A' (App. A (7)(a)(1))
This SW-NE section across the center of the field shows the oilfield's lateral seal of fluid injection by the Arroyo Grande Fault to the north and by the stratigraphic pinch out or facies change from the Edna Member (Dollie sand) to the Miguelito siltstone and claystone to the south. The basal Dollie sand that extends south of the main body of the oilfield reservoir to well Tiber 68 is not part of the steam drive.

Section B – B' (App. A (7)(a)(2))
This W-E section across the middle of the field shows that the lateral seal of the oil field reservoir on the upper western and eastern limbs of the syncline is a tar seal. The shallowing upward base of the bituminous sands or tar seal on the western limb of the syncline comes to surface on the section between wells Signal – Guidetti 2 and Guidetti A-4 and this is consistent with Hall's (USGS, 1973) surface geologic mapping of the Edna Member. On the east limb of the syncline the tar seal is estimated to come to surface east of the "Jack" 1-32 well on the east end of the section where the tar seal is approximately 480' below surface. No additional wells were available east of "Jack" 1-32.

Section C – C' (App. A (7)(a)(3))
This N-S section along the west side of the field shows the oil field's lateral seal of fluid injection by the Arroyo Grande Fault to the north and by the stratigraphic pinch out or facies change from the Edna Member (Dollie sand) to the Miguelito siltstone and claystone to the south. The basal Dollie sand that extends south of the main body of the oilfield reservoir to well "Adams" 1 is not receiving injection.

Section D – D' (App. A (7)(a)(4))
This W-E section along the north side of the field shows the Arroyo Grande Fault as the lateral seal to the oilfield reservoir to the east. To the west the section ends with well "PPG" 21 where the Edna Member (Dollie sand) sands are wet (i.e. contains mostly water) except for 200' of "tar" or bituminous sands from surface. Not shown on the section is well "Guidetti" A-12, the next closest well to the west, approximately 2300' further west. This 780' deep, 1959 well, was drilled for geological data only. It shows no oil saturation other than a "very slight dead oil staining" and minor particles of bitumen throughout. The shallowing upward base of the bituminous sands or tar seal on the western limb of the syncline comes to surface between wells "PPG" 21 and "Guidetti" A-12 and this is consistent with Hall's (USGS, 1973) surface geologic mapping of the Edna Member Dollie sand.

Section E – E’ (App. A (7)(a)(5))

This W-E section on the south side of the field shows the Edna Member (Dollie sand) sands pinching out into the Miguelito Member siltstones and claystones to the south. This section is approximately 700’ south of the steam drive. Well “Rock” 85 is adjacent to Phase IV Sentry monitoring well MW-2 which has not shown any events related to oilfield operations since it was installed nine years ago.

Section F –F’ (App. A (7)(a)(6))

This SW-NE section on the east side of the field shows the lateral seal of the oilfield reservoir to be a tar seal to the SW and the Arroyo Grande Fault to the NE. Well “Morehouse” 2A is wet to a depth 815’ MD other than for 50’ of bituminous sand at the surface. The next well to the east is “Morehouse” 3 which made significant oil production so a tar seal is inferred between the two wells.

# 3. JUSTIFICATION FOR AQUIFER/ZONE EXEMPTION

**Provide general introduction to Code of Federal Regulations (CFR) 40 CFR 146.4 and California “beneficial uses” requirements for justification:**

(✓ ) Aquifer does not currently serve as a source of drinking water; and

(✓ ) It cannot now and will not in the future serve as a source of drinking water because:

(✓ ) It is mineral-, hydrocarbon- or geothermal-energy producing, or can be demonstrated by a permit applicant as part of a permit application for a Class II or Class III operation to contain minerals or hydrocarbons that considering their quantity and location are expected to be commercially producible; or

( ) It is situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical, or

( ) It is so contaminated that it would be economically or technologically impractical to render that water fit for human consumption; or

( ) It is located over a Class III well mining area subject to subsidence or catastrophic collapse, or

( ) TDS is more than 3,000 and less than 10,000 and is not reasonably expected to supply a public water system or to have any other beneficial uses.

# 4. Aquifer/Zone Characterization

## 4.1. Edna Member/Dollie sands/Pismo formation

The oilfield reservoir is comprised of the Late Miocene-Pliocene Edna Member arkosic marine sandstone of the Pismo Formation as defined by the USGS. The Edna Member is equivalent to the DOGGR defined Dollie Sands. Appendix A (1) shows both the USGS and DOGGR stratigraphic columns and the nomenclature relationship between the two.

The Edna Member is the basal member of the Pismo formation. Overall, the Pismo Fm. records a period of transgressive deposition during a rise in global sea level. The Edna Member is comprised of a sequence of stacked, mostly coarsening upward sands. The arkosic Edna sandstone is thought to be primarily reworked Atascadero Fm. sandstone whose provenance is the Cretaceous Salinian Block granitic rocks to the east. Sands range from very-fine to coarse-grained and conglomerate and may be massive, bioturbated, cross-bedded or cemented. The Edna Member represents an inner shelf neritic sand facies which grades laterally into the coeval Pismo Fm. Miguelito Member which represents outer shelf neritic and basinal claystone, siltstone and diatomite facies. Reworked Monterey Fm. siliceous shale, Obispo Fm., and Franciscan Fm. volcanic rock clasts are also present. The Pismo Fm. unconformably overlies the Upper Miocene Monterey Fm. siliceous shale which is the hydrocarbon source rock for the Pismo Basin. The upper, shallow marine to non-marine members of the Pismo Fm. have been eroded away at the Arroyo Grande oilfield.

Structurally, the field is located in the east-west oriented, upright, open, doubly-plunging Tiber syncline on the north flank of the regional Pismo Syncline (App. A (4-1)). The field is approximately 4800' wide, 7700' long and extends from the surface to about 1700' in depth. There are maximum dips of 35 and 22 degrees on the north and south flanks respectively, while the maximum dip to the east and west is ten degrees. The Edna Member (Dollie sands) thins up-dip on the flank of the Tiber Anticline indicating syn-tectonic deposition (App. A (7)(a)(3)). Several of the stratigraphic markers are bentonite layers which are the alteration product of volcanic ash. These layers make extremely good chronostratigraphic markers and provide excellent mapping surfaces (App. A (2)). Regionally, the Pismo Fm. in the Pismo Basin is coeval and genetically similar with the neighboring Santa Maria Basin Sisquoc Fm. Tinaquaic Member and the Santa Margarita Fm. in the Huasna Basin (App. A (8)). In the Late Miocene-Pliocene, the Santa Maria, Huasna and Pismo Basins were part of a group of rapidly subsiding extensional wrench-fault basins between the West Huasna Fault and the Hosgri Fault on the continental margin. These faults are part of the San Andreas right-lateral strike-slip fault system (App. A (9)).

Hydrocarbons are distributed throughout the oilfield reservoir, both vertically and aerially. There are no non-hydrocarbon-bearing sands in the oilfield. For example, cross-sections along the west side and from the west side to the center of the oilfield demonstrate this (App. A (7)(a)(3); A (7)(a)(2)). The west side cross-section shows oil saturated sands (dark green shading on the resistivity curve and sidewall cores) continuously from north to south. Likewise, the west side to central cross-section shows oil sands thickening into the center of the syncline. The pervasive nature of oil distribution is evident in a map of sidewall and whole data shown on the M-2 structure map in Appendix A (4-1) and all of the cross sections in Appendices A 7 a (1-7). This is reinforced in a cumulative oil production bubble map in Appendix A (10). In addition, pre-1974 oil well completions demonstrate oil production at all levels of the reservoir that are being developed currently (App. A (7)(a)(7)).

**<u>Oilfield Reservoir Containment</u>**

<u>North Side Of The Oilfield</u>

The reservoir is bounded by the Arroyo Grande Fault and multiple fault splays north of the main fault (App. A (7)(a)(1)). The Arroyo Grande Fault is a reverse fault, with the hanging wall on the south side or oilfield side. This fault and its splays provide a seal to fluid or steam migration northward from the oilfield.

<u>South Side Of The Oilfield</u>

The reservoir thins and pinches out (facies change) up-dip into the Miguelito Member over the Tiber anticline forming a stratigraphic seal (App. A (7)(a)(1)). The reduction in permeability from the Edna Member Dollie sands to the Miguelito Member siltstones and claystones provides the seal to fluid or steam migration southward from the oilfield.

East And West Side Of The Oilfield

The reservoir thins and pinches out (facies change) up-dip into the less permeable, finer-grained Edna Member sands and to the very fine-grained Miguelito Member siltstones and claystones. The reduction in permeability to finer-grained sands, siltstones and claystones provides the seal preventing fluid or steam migration eastward or westward from the oilfield (App. A (7)(a)(2)).

Surface Of The Oilfield

Tar-filled Edna Member sands (asphalt) form a seal preventing migration of fluid or steam upward from the formations below. Also, there is no continuous water-bearing alluvium above the oilfield. Numerous surface seeps of oil are located in the Arroyo Grande oilfield and have been for centuries. Possibly the first written account of the surface seeps comes from the Spanish explorer, Gaspar de Portola. In a journal entry from 1770, he describes the many outcrops of tar. Anecdotal evidence suggests that any perceived increase in the seepage of oil is from solar heating or from rainfall floating out the oil. FM O&G wells are completed a minimum of 250' below surface. DOGGR cross sections from 1958 (App. A (6-1)) validate that shallow tar sands form the upper seal throughout the oil reservoir.

The Arroyo Grande Oilfield is unusual in that:

1) The trap that contains the hydrocarbon accumulation is a syncline, which is a rarity from the standpoint of known oil fields worldwide; thus, it's physical configuration and natural gravitational forces generally enhances liquids/ fluids containment; and

2) To effectively steam-flood the total net pay column, which in places is over 1,000 feet thick, prudent reservoir heat management becomes a necessity; this, in turn, will provide necessary control of steam movement and reservoir conformance.

Significance of Synclinal Trap

One of the issues of recent concern by regulatory agencies involves the low (<3000 ppm) TDS content of the reservoir water at Arroyo Grande oilfield. In a general sense, this is completely understandable, since so few reservoirs having commercial oil accumulations are associated with synclinal traps. It is generally accepted that the original water in place associated with the Arroyo Grande reservoir was originally of notably higher salinity given the marine depositional environment. It would therefore be reasonable to surmise that, over geologic time the oil weathered, such that we now have a near-surface tar seal and oil that is about 13 degrees API gravity in the reservoir. Along the way, meteoric waters were apparently able to gradually dilute, and eventually largely replace, the original formation brine. As this hypothesized process was apparently able to take place without displacing the oil, the implication would be that the oil viscosity had already changed sufficiently to make the water-oil mobility ratio quite unfavorable, i.e., the oil was already too viscous to be displaced by the invading water.

$$water{\sim}oil\ mobility\ ratio = \frac{\left[\frac{relative\ permeability\ to\ water}{(Water\ viscosity)}\right]}{\left[\frac{relative\ permeability\ to\ oil}{Oil\ viscosity)}\right]}$$

Natural gravitational forces promote containment of all injected produced water within the syncline. The produced water injected on the western flank of the reservoir moves back down-dip toward the bottom of the syncline. Although the practice of returning produced water back to the formation it was originally recovered from is inefficient from an oil production perspective, the natural geologic confinement offered by the reservoir formation was determined to be the best option for ensuring zonal containment of the water disposal stream.

Water injection into the reservoir, via disposal wells open at depths between about 600 and 900 ft., has been underway since the mid-1970s. By the early 1980's, injection operations exceeded 10,000 bbl./day (1.29 acre-Ft per day). Cumulative water injection into the producing horizons is estimated to have totaled 100 million bbl., (12,890 acre-ft) (App. E (2)). No incidents or observed detrimental effects to the localized environment or groundwater resources have been documented since injection operations into the Dollie zone were initiated, thus providing anecdotal support to the observations that the reservoir is geologically confined.

To improve efficiencies with the oil production operations, the Water Reclamation Facility (WRF) was designed to dewater the reservoir by returning less produced water to the formation than was being withdrawn in conjunction with the oil (App. H). Since becoming operational in 2013, treated produced water discharges to Pismo Creek from the WRF have exceeded approximately 9.8 million bbls (1,263 acre-ft). Total oil and water withdrawals from the producing formation are estimated to have exceeded 29 million bbls (3,738 acre-ft) to date. The average production, injection, and water released to Pismo creek for 2015 are presented in Table 4-1 and show a net loss of fluid for the reservoir.

| Unit of Measurement | Oil Produced from Reservoir | Water Produced from Reservoir | Water and Steam Reinjected into Reservoir | Water Released to Pismo Creek |
|---|---|---|---|---|
| **bbl/day** | 1,350 | 29,750 | 11,700 | 18,050 |
| **acre-ft/day** | 0.17 | 3.83 | 1.51 | 2.33 |

*Table 4-1*

The process of reservoir de-watering has now been underway for over 2 years. This is gradually lowering the reservoir pressure, which both allows more efficient thermal recovery operations and also makes the down-dip path of flow of any injected water more definitive due to the increased pressure sink that is being created. This reservoir de-pressuring will be further emphasized beginning late-Summer 2015, when the WESP (i.e., Wet Electrostatic Precipitator) and gas incinerator currently being installed is expected to be completed and operational, which will result in essentially all current gas reinjection (of over 2.0 MMSCF/day) into the reservoir being eliminated.

Water injection into wells "Signal E.T.S." 9N and "Pulas" 3, with cumulative injection of 8.2 million bbl (1,057 acre-ft) and 5.9 million bbl (760 acre-ft) respectively, stayed in the trough of the syncline and appear to have improved recovery in these same zones in offset wells that were subsequently drilled and logged (based on the observed reduction in oil saturation relative to pre-injection conditions) (App. E (3-1, 3-2, 3-3)).

Over the next 10 years, additional reservoir de-pressuring (voidage) will be achieved by producing oil and sending an estimated 73 million bbls (9,410 acre-ft) of water to the creek (based on water plant maximum output of 20,000 bwpd (2.58 acre-ft/day) to Pismo creek).

Reservoir Heat Management Influence on Fluids Movement/ Containment

The current approach to steam-flooding at the Arroyo Grande Oilfield centers around reservoir heat management, utilizing limited entry and critical flow calculations for perforation design when completing new injection wells. Employing best management practices developed for heavy oil reservoirs that FM O&G operates in the San Joaquin Valley (Kern County), a dual-string 3.5" ID slim-hole completion has been adopted as the standard for new steam injectors. One of these strings targets approximately the lower half of the total net pay column and the other targets the upper half. Within each string, a determination is then made to select the appropriate interval (starting with the deepest pay, and working upward) such that critical flow can be achieved into all perforations and that the target steam rate (typically between 1.0 to 3.0 barrels per feet of net pay) can be achieved. Currently the steam-flood patterns being utilized are approximately 1.25 acre each, using an inverted 9-spot design. This minimizes the chances of steam bypassing the producing wells (where it could move notably outside the pattern). The stated initial rates are only maintained about 2 years, after which a step-down of injection (e.g., cutting 15-20% of rate every 2-3 years) will follow – until the point is reached (e.g., after 10+ years) where steam is only injected periodically and in just sufficient volume to keep the reservoir from cooling. Because of the substantial net pay thickness to be steam-flooded, and because operations are materially impacted by surface usage constraints that must be adhered to, the initial completion interval may take 20 years or more to deplete; at that point, a recompletion in the upper part of the injection string will occur (in wells where justified), and the steam-flood process described will be repeated.

While steam is much less dense than the oil in the reservoir it is heating (making gravity over-ride a possibility), and heat will naturally migrate up-dip to some extent, heat losses within the reservoir become substantial over relatively short distances. Such heat loss will cause condensation of the steam, with gravity then serving to reverse the direction of flow (of hot water) and effectively work in a self-containment fashion. To further strengthen FM O&G's reservoir and heat management capabilities, a number of permanent, temperature observation wells have been situated between the steam drive and the Arroyo Grande fault such that the steam movement can be closely monitored (App. I (1)(a)).

**Regional Hydrogeologic Setting**

Regional hydrogeologic features surrounding the Arroyo Grande oilfield are shown in Appendix A (3-1). These features include groundwater basins and subbasins recognized by the California Department of Water Resources (DWR), along with two structural subbasins which have been defined by Cleath-Harris Geologists (CHG) in prior work. The structural subbasins are areas where groundwater aquifers have been identified and characterized, and are within the San Luis-Pismo block, part of the Pismo sedimentary basin.

San Luis-Edna Groundwater Basin

The San Luis-Edna groundwater basins, also referred to as the San Luis Obispo Valley groundwater basin, is DWR basin number 3-9. The division between the San Luis and the Edna subbasins is a subsurface divide just south of the County airport. Originally, the Edna subbasin was called the Pismo basin (DWR, 1958, Bulletin 18), and included the alluvial deposits in upper Price Canyon through the confluence with Canada Verde Creek. By 1975, outlines of basin 3-9 had eliminated the portion entering Price Canyon (DWR Bulletin 118). Due to the small scale of the maps used during development of Bulletin 118 basin boundaries (1:250,000), the boundaries do not always match with local scale (1:24,000) maps. Subbasin limits are adjusted slightly herein to more accurately follow the geologic features as mapped by Hall (1973), compared to the published Bulletin 118 boundary.

The more productive wells in the Edna subbasin produce mainly from Paso Robles Formation terrestrial deposits to approximately 150 feet depth and from an underlying marine sand facies interpreted, based on Hall (1973), to be the Squire Member of the Pismo Formation. Well capacities from these aquifers can be up to several hundred gallons per minute (gpm).

The subsurface hydraulic connection between the Edna subbasin and Price Canyon waterbearing zones is restricted by faulting and folding, which act as barriers to groundwater flow. When the aquifers of Edna Valley are fully saturated, subsurface flow into Price Canyon may occur through the alluvial deposits.

<u>Santa Maria Groundwater Basin</u>
The Santa Maria groundwater basin (DWR basin 3-12) covers approximately 288 square miles, of which approximately 184 square miles are within San Luis Obispo County. The main basin lies between the Pacific Ocean and the Wilmar Avenue fault, which generally parallels Highway 101. One of the three subbasins comprising the Santa Maria groundwater basin in San Luis Obispo County, the Pismo Creek Valley subbasin, extends into Price Canyon. Groundwater within the Pismo Creek Valley subbasin flows to the southwest into the main basin area near coast (DWR, 2002).

The Bulletin 118 subbasin boundary for the Pismo Creek Valley extends into the oilfield activities area, however, a 2007 study by WZI (Bakersfield, California) concluded that the alluvial aquifer did not extend north into the oil field area. The northern limit of the subbasin was further refined by URS in a 2013 groundwater quality assessment Appendix A (3-1).

<u>San Luis-Pismo Structural Block</u>
The San Luis-Pismo structural block is within the Pismo sedimentary basin, a regional tectonic feature. The block trends northwest-southeast between the Hosgri and Huasna fault zones and is flanked by the Wilmar Avenue fault to the south and the Edna-Los Osos Valley fault zone to the north in the Price Canyon area. The structural subbasins identified herein are developed along the Pismo syncline, which is the dominant structural feature in the block.

*Indian Knob Valley Subbasin*
The "Indian Knob Valley" is not a formal name but has been assigned by CHG to the topographic depression due south of Indian Knob, east of Gragg and Squire Canyons and west of Price Canyon. Within the valley, the beds have been folded, forming a syncline that plunges to the west into the San Luis Obispo Creek watershed. The syncline is bounded on the northeast by the Indian Knob fault.

Water-bearing beds within Indian Knob Valley include the Gragg and nonbituminous Edna Members of the Pismo Formation. Also underlying the valley are non water-bearing claystones and siltstones of the Miguelito Member of the Pismo Formation, bituminous sandstone of the Edna Member, and diatomite and shale of the Monterey Formation.

Both the Gragg and the Edna Members have sufficient permeability and thickness locally to provide greater than 50 gpm capacity wells. Springs issue out of these two members of the

Pismo Formation and contribute to the flow in the tributary to Pismo Creek and associated alluvial deposits. The Indian Knob Valley subbasin appears structurally and hydraulically isolated from other water-bearing zones in the study area.

*Oak Park Subbasin*

The Oak Park structural subbasin, also referred to as the Meadow Creek basin, encompasses approximately 6,200 acres, and its boundary is defined by the areal extent of a basal, 300-foot thick fine to medium quartz sand aquifer. The subbasin is developed along the Pismo Syncline, where a plunging and then rising fold axis forms a bowl structure centered in the Arroyo Grande Oak Park area.

There are two or three shallower (and thinner) sand aquifers overlying the main zone, with thick clayey interbeds. The main (deep) aquifer has only been tapped by wells along the subbasin margins, as it reaches depths in excess of 1,000 feet beneath much of the subbasin interior.

Wells completed in the deep aquifer provide capacities in excess of 50 gpm to wells. The Oak Park subbasin, which covers areas mapped as Edna and Squire Members of the Pismo Formation, appears structurally and hydraulically isolated from other water-bearing zones in the study area.

**Price Canyon Water Analysis**

Recent and historic water analyses document that Total Dissolved Solids (TDS) levels for the naturally occurring groundwater within the oil reservoir are typically below 2,800 ppm. This is likely attributable to the fact that synclines are good for water accumulation and water drilling can often be done successfully in such areas, except in cases like Arroyo Grande where oil is present.

However, despite the low TDS levels occurring throughout the oil reservoir there are several other naturally occurring chemicals that make the waters non-potable for human consumption or un-useable for agriculture or livestock. Appendix D (1)(a) summarizes recent and historical water geochemical analysis from oil wells, water supply wells and sentry wells inside and outside the 1974 productive limits. The data demonstrates that the naturally occurring presence of volatiles, hydrocarbon saturation and metals make the water unsuitable for drinking water or other beneficial use. Data highlighted by red in the table represent exceedances of either drinking water or Basin Plan standards for water quality that is fit for human consumption, agricultural use, or livestock use.

**Best Use Of Groundwater Resources**

The overriding consideration in evaluating the best potential use for the aquifer is the fact that hydrocarbons are present throughout the oil reservoir. This is due to the synclinal structure in which the oil resources were trapped and accumulated. Absent some sort of oil separation and water treatment process, the in situ groundwater from within the reservoir cannot be utilized for any type of purpose including but not limited to drinking, agricultural irrigation, or habitat enhancement.

Accordingly, the highest and best use of the in situ ground water that is currently produced as a byproduct of the oil production process is for the generation of steam for use in the Enhanced Oil Recovery operations. The groundwater in its natural state contains free oil and multiple contaminates that exceed various Federal, State, and RWQCB Basin Plan water quality standards for benzene, selenium, toluene, ethyl benzene, xylene (App. D (1)(a)). Another key factor in determining the best use of the in situ groundwater resources is that the zone is not productive enough to be a commercial water source. This statement can be documented by current oil production rates. The Arroyo Grande Oilfield currently produces approximately 1,350 bopd (0.174 acre-ft of oil per day) and 30,000 bwpd (3.87 acre-ft/day) from 187 production wells. This works out to an average of 7 bopd (0.2 gpm oil) and 160 bwpd (4.7 gpm water) per well. According to California Department of Water Resources (DWR) Bulletin #118, the typical water well in the San Luis Obispo groundwater basin yields an average 300 gpm and a maximum of 600 gpm. Consequently, within the confines of the reservoir syncline it would take 60 oil producing wells to equal one typical water well in the surrounding region.

As stated earlier, the fluid production from a typical Arroyo Grande oil well is a mixture of oil and water that has to be separated. Standard oilfield equipment is used to separate the oil from the water. The water is then filtered and split into two streams. One stream is softened for use in the Enhanced Oil Recovery process called Steam Flooding (9,000 bwpd or 1.16 acre-ft/day). The remaining water (21,000 bwpd or 2.71 acre-ft/day) is sent thru a Water Reclamation Facility (WRF) using a high tech filtration system followed by reverse osmosis filters. Three quarters of the water sent through the facility is purified and released into Pismo Creek in accordance with an NPDES permit issued by the Central Coast Regional Water Quality Control Board (CCRWQCB) (approximately 15,750 bwpd or 2.03 acre-ft/day). A small portion of the water (750 bwpd, 0.097 acre-ft/day) is evaporated during the cooling process to meet water discharge specifications while the remaining balance is re injected in to the oil producing formation as discussed below.

Waste waters from the facility are commonly referred to as “reject water”. The reject water stream is injected into the oil producing formation where the water was originally produced. Eight injection wells currently dispose of the entire reject stream on the western flank of the oil reservoir. Seven of the reject injection wells are outside the current exempted aquifer and one is inside.

Gravitational forces pull the injected water to the bottom of the syncline where the injected water is withdrawn again along with additional oil. On average, approximately 4,500 bwpd (0.58 acre-ft/day) of reject water is currently being injected in to the oil reservoir. The WRF’s reliance on the water disposal wells was referenced in various documents as part of NPDES permit application process.

At peak production of 55,000 bwpd (7.1 acre-ft/day), the WRF is capable of discharging up to 20,000 bwpd (2.58 acre-ft/day) into the creek. The discharged water augments the Federal and State Listed Endangered Species Southern California Steelhead Habitat and Tidewater Goby critical habitats found in Pismo Creek and downstream at the Pismo Creek estuary. If injection of the waste waters from the WRF into the oil reservoir is not allowed, operations at the WRF will be shut down, subsequently eliminating the water supply that is currently benefiting the Southern California Steelhead and Tidewater Goby habitat.

In short, the existing oil field operations as configured with the WRF and affiliated water disposal injection operations are currently generating water that is providing both economic and habitat beneficial uses that would otherwise not be possible based on the naturally poor quality of the in situ groundwater. Absent the utilization of infrastructure to separate out the oil and treat the groundwater, the groundwater resources would essentially be “stranded” in their native state, unable to provide any societal, habitat or economic benefit. The current operations constitute the “best use” of the groundwater resources as they provide a utilization for a resource that cannot otherwise not be utilized.