THE USE OF BETA-C TITANIUM FOR DOWNHOLE PRODUCTION CASING IN GEOTHERMAL WELLS

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ABSTRACT

The hot, hypersaline brines of the Salton Sea geothermal field contain vast amounts of recoverable energy. However, conventional carbon steel tubulars have been corroded in these brines at rates greater than 1000 mpy. This severe corrosion has been a major impediment to development of this field.

Field testing of both coupons and full size tubulars since 1983 has shown that Beta-C titanium is immune to corrosion and resistant to hydriding in these geothermal brines.

A manufacturing procedure has been developed to produce thin wall Beta-C titanium in Range III lengths with yield strength greater than 100 ksi and diameters larger than 8-5/8". Although special consideration must be given to titanium casing string, Beta-C titanium completions are a cost-effective option for geothermal production wells in the Salton Sea field.

INTRODUCTION

Geothermal energy is the natural heat of the earth contained in reservoirs of fluids that are trapped in rock formations at depths of thousands of feet. The most common use of this energy is to power plants that generate electricity. Fluid is produced from wells as steam or as a mixture of steam and water (or brine). In the case of the two-phase mixture, the steam is separated from the water, or the total mixture is used to vaporize (flash) a power fluid (often isobutane). The steam or power fluid is used to drive a turbine generator which produces electricity.

Electrical generation plants powered by geothermal resources are operating in 17 countries. Currently, world-wide generation of geothermal power is 4733 MW with 2007 MW (1) developed in the United States. The Salton Sea geothermal field, located in the Imperial Valley of California, is one of the world's largest geothermal resources. The estimated potential of the Salton Sea field is over 3,000 MW.(2)

The geothermal fluids of the Imperial Valley are characterized by hypersaline brines with a total dissolved solids content ranging from 150,000-300,000 parts per million (ppm), and temperatures ranging from 450-600°F (232-315°C). The brines also contain H_2S and CO_2. A chemical analysis of a typical Salton Sea brine is given in Table 1 (<5 ppm not shown).

Table 1. Typical Brine Composition of a Salton Sea Well (pH = 5.8)

Element	ppm	Element	ppm	Element	ppm	Element	ppm
As	8	Pb	66	SiO_2	658	Br	68
Ba	100	Li	177	Na	59,800	Cl	126,700
B	301	Mg	80	CO_2	125	I	5
Ca	24,000	Mn	785	Sn	402	SO_4	22
Cu	7	K	12,840	Zn	287	TDS	261,800
Fe	708	Rb	62	NH_3	339	H_2S	90

These geothermal fluids are recovered from reservoirs located between depths of 2,000 ft. and 6,000 ft. Wells are drilled using techniques similar to those employed by the oil and gas industry. The two-phase fluid flows unassisted to the surface, and a direct flash is used to produce steam to drive the turbine generator.

Early Operations

The high temperature and high salinity of the Salton Sea brines, along with the presence of H_2S and CO_2 make them one of the most corrosive, naturally occurring fluids known. Because of the corrosive brines, wells completed at the Salton Sea Field in the late 1970's contained a retrievable production string hung from the surface rather than cemented production casing which is used in most other geothermal production areas. The retrievable production string made it possible to test materials in the well and to retrieve them for inspection. Early flow tests at the Salton Sea were generally short duration because of difficulties in handling the brines on the surface. Because of these short flow periods, corrosion resistance of carbon steel tubulars was not well quantified. This fact and its low cost made carbon steel the material of choice at the start of commercial operation.

Field Experience After Start of Commercial Operation

The severity of the downhole corrosion problem became apparent after the Salton Sea, Unit 1, 10 MW plant began commercial operation in July of 1982. Carbon steel production strings showed both pitting and general corrosion rates as high as 1,000 mils/year (25.4 mm/yr). Others have reported localized corrosion rates as high as 2,000 mils/yr at the bottom of a Salton Sea well (3).

Unocal's oil field experience and coupon testing accomplished in other operations indicated that minor additions of Cr and Mo to carbon steel improved corrosion resistance. Based on this information, a 9Cr-1Mo hangdown string was used to replace the carbon steel. After a 133 day period, during which the well was produced for 78 days, the 9Cr-1Mo string was retrieved. The inspection showed deep, flat bottom, crater-like pits throughout much of the string.

Many of the pits near the lower end of the string had perforated the casing wall. There was little general corrosion. Based on an operation period of 78 days and a nominal wall thickness of 0.4 inches, the pitting rate of the 9Cr-1Mo production casing was about 1,870 mils/yr. At this point, it was concluded that there were no inexpensive alloys that would withstand these geothermal brines. Fortunately, corrosion coupons and full size joints of other alloys were included in the 9Cr-1Mo string and provided data to direct further work.

Material Testing

Corrosion coupons were placed at the bottom and top of a production string in Well A and in the two-phase line on the surface. The conditions at these locations are shown in Table 2.

Table 2. Coupon Exposure in Salton Sea Well A

Location	Depth (ft.)	Approximate Temperature, °F	Approximate Pressure, psi
1	1858	507	700-750
2	451	456	350-460
3	Surface	430	300-420

Two-inch by four-inch flat coupons were used for the pitting and crevice corrosion tests and U-bends for the stress corrosion cracking (SCC) tests. The alloys considered had previously shown negligible uniform corrosion rates, so the corrosion mechanisms of concern were pitting, crevice corrosion, and SCC. The alloys or family of alloys that were tested as coupons were as follows: 9Cr-1Mo steel, Type 316 SS, duplex stainless steels (SS), Ni-Cr-Mo alloys, Ni base alloys, and titanium alloys including Ti-3Al-8V-6Cr-4Mo-4Zr (Beta-C). In all, 20 different alloys were tested as coupons, with some duplicated as full joints.

Two important pieces of information were learned from these tests. First, none of the alloys were completely immune to corrosion damage. Second, the corrosion rate measured on a full size tubular was not the same as the corrosion rate measured on a coupon of the same alloy. Consequently, the coupon data were used as a screening method to select alloys that were then tested as full size tubulars.

In the full size tubular tests, Beta-C was the least expensive of the materials which were immune or nearly immune to corrosion attack. Since there were less expensive materials which, while not immune, were more corrosion resistant than carbon steel, a cost comparison was made. The same method was used as the one used to compare Beta-C with carbon steel, which is discussed later in this paper. Based on this analysis, Beta-C was the most cost effective material tested.

Full Size Beta-C Tubular Tests

The Beta-C was selected for additional testing. In addition to corrosion resistance, the alloy could be produced to meet the following requirements:

1. Strength : greater than 80,000 psi yield strength at 500°F to withstand thermal stresses if cemented in place.
2. Size: available in seamless, thin wall casing to 13-3/8 inches outside diameter.
3. Length: available in Range III lengths.

A series of tests were performed using full-size Beta-C tubulars. The location and duration of these tests are shown in Table 3.

Table 3. Testing of Full Size Beta-C Tubulars

Test #	Diameter (in.)	Length (ft.)	Well	Depth Below Ground Level (ft.)	Duration days	Production Time days
1	8-5/8	15	A	1843-1858	256	220
2	8-5/8	59	B	1453-1512	414	326
3	8-5/8	70	A	1776-1846	833	714
4	9-5/8	1520	B	0-1520	425	411

At the conclusion of Test 1, the sample of Beta-C was retrieved from the well, split open, and examined visually. No pitting corrosion was found. Tensile tests were performed and hydrogen concentrations were measured on this sample and on a control specimen cut from this joint of pipe but not run in the well. Results of these tests are shown in Table 4.

Table 4. Tensile Properties and Hydrogen Analysis of Beta-C from Test #1 and 3

Parameter	Test #1 Exposed Sample	Test #1 Control	Test #3 Exposed Sample	Test #3 Control
Ultimate Strength, ksi	181-183	175-183	143	145
Yield Strength, ksi	174-181	162-167	140	142
Elongation, %	7-8	8-11	7	8
Hydrogen Content, ppm	125	103	140 - 157	165

No degradation of mechanical properties was noted and hydrogen content was unchanged. The hydrogen concentration is substantially below the 2000 ppm threshold at which Beta-C begins to show embrittlement (4).

Tests 2 and 3 began immediately after the conclusion of Test 1. These tests were designed to confirm the corrosion resistance of Beta-C for longer time periods and to demonstrate the viability of the manufacturing process. The sample joints retrieved in Test 2 were examined on the ends and again showed no evidence of pitting corrosion.

Samples retrieved in Test 3, after more than two years downhole, were cut open and examined visually. One sample did show evidence of localized corrosion occurring at a rate of approximately 7 mpy. A microhardness analysis and metallographic examination showed that this localized attack had initiated from an area where surface contamination had not been completely removed from the I.D. surface. The mechanical tests and hydrogen analyses performed in Test 1 were also repeated. The results are shown in Table 4. Again, there was no evidence of mechanical property degradation or hydrogen pick-up.

Test 4, the full 1500 foot string of 9-5/8 inch O.D. Beta-C was completed at the same time as Test 3. The 48 joints were retrieved and inspected on the ends. Only two joints showed evidence of underdeposit crevice attack. A sample was cut from one of the affected joints. Testing again confirmed that the local attack was associated with incomplete removal of surface contamination.

Additional samples were cut from three other joints and the mechanical tests and hydrogen analyses performed.

These tests did indicate that some additional aging had occurred during the exposure period. Subsequent analyses determined that at least one lot of casing had not been completely aged prior to installation. Additional testing showed that proper heat treatment could restore the casing to specification property levels with the necessary stability for long term elevated temperature service.

Stress Corrosion Cracking Tests of Beta-C

Concurrent with the full size tubular tests, several stress corrosion cracking (SCC) tests were performed to determine if Beta-C was susceptible to cracking. C-rings that were stressed to 80% and 100% of yield strength were exposed to actual downhole conditions. There was cracking of the first set of C-rings. The failures were attributed to a heavy alpha case on the surface of the C-rings. A second set of C-rings with the alpha case removed was then tested downhole and these C-rings did not crack.

Slow strain rate tests were conducted in a synthetic brine at downhole temperature and pressure conditions. The Beta-C did not show cracking tendencies in this test.

The SCC tests that were done provided sufficient proof that the Beta-C would not crack in the Salton Sea brines. The final proof is that none of the tubulars that have been in service to date (over 800 days for one string) have cracked.

Cost Comparison of Beta-C to Carbon Steel

In the highly corrosive environment described, the cost of production casing is a major portion of the total expense. This is true whether a low cost, heavy wall, carbon steel string is used and replaced at regular intervals, or a corrosion resistant material is cemented in place for the assumed 30 year life of the well. The first approach depends on the removal of the casing before a catastrophic corrosion failure occurs.

A cost analysis of these two alternatives is sensitive to the discount rate and to the price of the materials which can fluctuate widely with supply and demand. However, a simplified model for comparison is presented below using current estimated material costs and a 15% discount rate.

Table 5 shows the assumptions used in determining the initial cost and expenditures incurred during the 30 year life. Sizes have been adjusted so that each completion will produce at equal rates. Thus the 9-5/8" O.D. carbon steel casing with a one inch average wall (AW) will have the same I.D. as 8-5/8" O.D. x 0.400 inch AW Beta-C. A simplified cumulative cash outlay for these two materials is shown in Figure 1. Over 30 years, the total outlay for carbon steel is 5,310 K$ compared with 990 K$ for the Beta-C. In actuality, a present worth cost (PWC) economic study is used to compare projects which differ in their cash flow timing. By this type of analysis the PWC for the titanium completion is 990 K$ or 26% less than the 1,339 K$ PWC for carbon steel. PWC can be thought of as the amount of cash deposited in an interest bearing account, at the beginning of the project, to pay the costs of the entire project.

Table 5. Beta-C and Carbon Steel Cost Comparison Assumptions

	Beta-C	Carbon Steel
Plant life, yrs.	30	30
Discount Rate	15	15
Tax consequences	Ignored	Ignored
Nominal O.D., in.	8-5/8	9-5/8
Wall thicknesses, in.	0.40	1.0
Inside diameter, in.	7.825	7.625
Density, lb/in.	0.174	0.283
Pipe cost-threaded & coupled, $/lb.	27	0.65
Weight of casing, lb/ft.	21.6	92
Casing length, ft.	1700	1700
Cost of casing, $	990,000	102,000
Well cost differential to accommodate larger casing ($)	0	75,000
Cost to replace corroded casing ($)	75,000	75,000

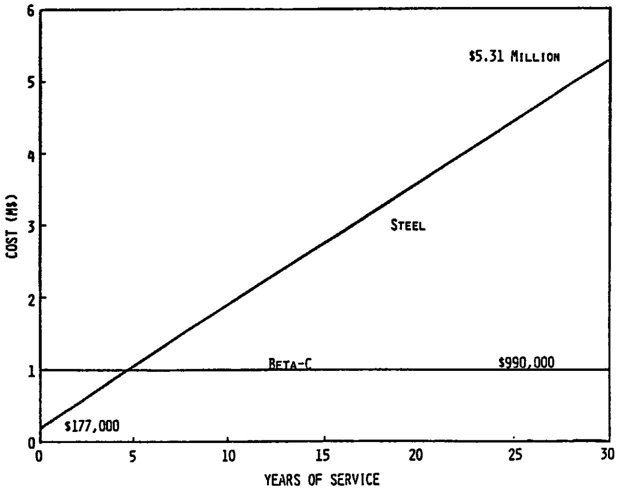


Figure 1. Cumulative Cash Outlay

This cost advantage, along with the additional safety afforded by a corrosion resistant material such as Beta-C, demonstrates this alloy to be an attractive material for Salton Sea geothermal producers.

Size Availability, Mechanical Properties, Heat Treatment, Fabricability

Material cost, expected life, and size availability are all important economic considerations in Salton Sea completions. Since cold work is not required to develop strength, the Beta-C alloy can be hot extruded to a wide range of standard casing sizes. A limitation of this method of manufacture is that wall thicknesses below 3/8 inch are not practical. Lengths up to 48 feet are available in the 8-5/8 inch O.D. to 13-3/8 inch O.D. range of casing used in this application. Maximum length casing reduces the number of premium joints and couplings which are machined from heavy wall stock of the same pedigree as the casing. Quality levels for both pipe and coupling stock are to the API standard 5AX, which is the American Petroleum Institute specification for high strength casing.

Mechanical properties for geothermal casing are determined at both room temperature and 500°F. Typical longitudinal tensile properties for solution treated and aged 9-5/8 inch O.D. x 0.395 inch nominal wall casing are shown in Table 6. While 6Al-4V offers sufficient srength at elevated temperature, the corrosion resistance was considered inadquate to warrant further testing at that time (5). Minimum wall thicknesses are determined on the basis of strength, collapse considerations, and what is practical to produce by the hot extrusion process. Sufficient stock must be allowed to insure that alpha case is removed from both the I.D. and O.D. surfaces.

Table 6. Mechanical Properties at Room Temperature and 500F

Grade	Temperature	UTS ksi	YS ksi	El %	RA %
Commercially pure	Room	70	60	20	35
(Grade 2)	500°F	32	20	35	70
6Al-4V	Room	135	125	8	20
(Annealed)	500°F	100	90	15	40
Beta-C	Room	165	155	14	25
(STA)	500°F	150	125	15	30

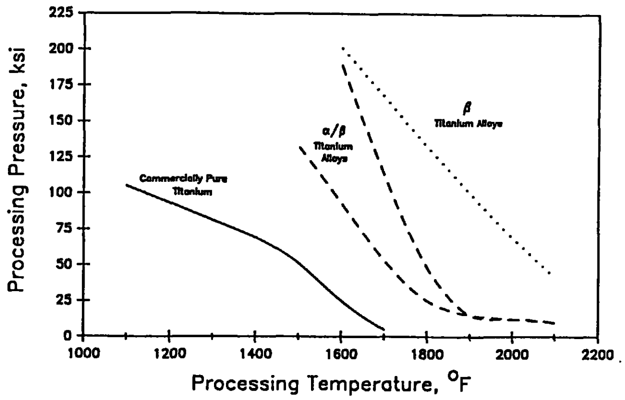
Proper selection of aging cycles must be characterized based on prior thermo-mechanical history. This is important to insure that casing not only meets the strength requirements, but will be metallurgically stable for long periods at exposure temperatures up to 600°F. Table 7 shows average properties for 8-5/8 inch O.D. Beta-C casing both prior to and after downhole exposure at 510°F for 20,000 hours. Preliminary screening of aging response is done by hardness. Hardness offers a correlation to strength similar to that of steel (6).

Table 7. Mechanical Properties of Beta-C Before and After Downhole Exposure

	Temperature	UTS ksi	YS ksi	El %	RA %
Before	Room	145	142	8	22
	500°F	127	115	11	23
20,000 hrs.	Room	142	140	9	28
	510°F	129	118	12	26

When this project was begun, an industry survey revealed only limited experience in the production of seamless titanium pipe. What information was available, for the most part, concerned commercially pure grades for the chemical process industry, 3Al-2.5V for aerospace hydraulic tubing, and small runs of 6Al-4V for shafting. Sizes were all below the area of interest and were extruded from forged and trepanned billets. While suitable for small diameters or short runs, this process was considered impractical from a cost standpoint for the sizes and quantities needed for the Unocal geothermal wells. Production runs of casing were, therefore, pierced and extruded which dramatically improved yields and at the same time lowered machining costs. This was a major cost savings particularly in this alloy system which is more difficult to machine and grind when compared to the industry standard 6Al-4V.

At lower extrusion ratios, temperatures as low as 1750°F have been successfully used to extrude Beta-C casing. Range III lengths, however, dictated maximum size tube hollows and correspondingly higher extrusion ratios. As shown in Figure 2, flow stresses for Beta alloys at moderate strain rates are well above those encountered for beta processed alpha + beta grades. For this reason, most of the geothermal casing was extruded at least 500°F over the transus (1375F). Lower strain rates are desirable when processing beta alloys, however, there are practical limitations to controlling this parameter and keeping the extrusion billets at proper temperature.



Conclusions

1. Extensive corrosion testing has not identified any inexpensive alloys that can provide an acceptable life in the Salton Sea geothermal environment.

2. Beta-C was the least expensive of the alloy tubulars tested that was immune or nearly immune to corrosion damage.

3. A simplified economic model shows Beta-C titanium to be more cost effective than conventional carbon steel oil country tubular goods.

4. The mechanical properties of Beta-C were not degraded by downhole exposure at 510°F (265°C) for 20,000 hrs.

5. Beta-C tubulars 8-5/8 inch O.D. to 13-3/8 inch O.D. in lengths up to 48 feet are available.

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