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ABSTRACT

Salton Sea Unit 2 is Unocal's newest geothermal power plant addition in the Salton Sea KGRA, located in the Imperial Valley, California. The project generates 18 MWe of electrical energy to a southern California utility from three turbines operating at three distinct pressures. The Unit achieved commercial operation on April 5, 1990 eighteen months after the start of design.

The unit has maintained a high availability and capacity factor. The cost per Megawatt was reduced by minimizing the design and construction time and maximizing the energy utilization of the produced brine. Unocal is also preparing for future development in the Salton Sea field and elsewhere with commercial-scale testing of Unocal-patented processes.

PART I - PROCESS DESCRIPTIONS

Salton Sea Unit 2 was constructed within the existing Unit 1 facility. Unocal's patented pH-modification process is employed in the Unit 2 Resource Production Facility (RPF), which processes steam for three turbines in the Power Generation Facility (PGF). Unit 1 consists of the crystallizer-clarifier RPF which processes steam for one turbine in the PGF. Unit 1 and 2 are operated as one facility.

Steam Systems

The four Unit 1 and Unit 2 turbines operate at three different pressures.

High-Pressure Steam (250-350 psig). Three to four wells supply two-phase brine to the Unit 1 and 2 wellhead separators (Figure 1). The separators control the rate of flow from the wells and render the Unit 1 clarifier solids non-hazardous.
as defined by the California Assessment Manual. This is accomplished by separating the non-condensible gases from the brine early in the process (Hoyer 1990). High pressure steam (325 psig) from the separator is directed through a turboexpander operating at a back-pressure of about 120 psig. The turbine-generator has a nameplate rating of 4.4 MWe.

Turboexpanders are commonly used in natural gas production, but have only recently found geothermal applications. The Rotoflow Corporation turboexpander is a 15,000 RPM radial inflow, variable inlet vane, reaction-type turbine. The impeller is similar to that of a centrifugal gas compressor. Rotoflow has several turboexpanders operating in a binary geothermal facility in Mammoth, California. However, no such machines were operating in steam service when Unit 2 was engineered and constructed.

Brine from the wellhead separators is treated using two different processes at Units 1 and 2. Iron silicate scale is precipitated from the brine at Unit 1 in the crystallizer-clarifier system (Moss 1982). Brine from the Unit 2 separators is treated with acid in the pH-mod process.

Standard Pressure Steam (90-120 psig)
The steam exiting the turboexpander is combined with steam from the Unit 1 standard pressure crystallizer and the Unit 2 standard pressure separator. The steam is split between the Unit 1 Fuji and the Unit 2 Mitsubishi turbine-generators. Both have 10.0 MWe nameplate ratings.

Low Pressure Steam (20 to 30 psig) Brine from the Unit 1 SP Crystallizer flashes into the LP Crystallizer, producing low pressure steam that is directed to the Unit 2 Mitsubishi LP turbine. The LP MHI turbine-generator has a nameplate rating of 5.4 MWe.

Unit 2 pH-Modified Brine

Unocal's pH-modification process is proving to be an effective method of stabilizing the Salton Sea hyper-saline geothermal brines before injection. The fundamental principle is to keep the silica and other elements in solution by adding hydrochloric acid (HCl), rather than using the controlled precipitation method (crystallizer-clarifier) of all of the other plants in the Salton Sea KGRA.

Brine Chemistry Iron silicate is the predominant scale component that deposits from brine produced at Units 1 and 2. (Gallup 1989a). For several years, Unocal investigated methods to control the deposition of iron silicate scale from both Salton Sea and Brawley brines. The early evidence suggested that silica concentrations could be kept below the amorphous silica saturation level by maintaining sufficiently high brine temperatures. However, since iron silicate deposits at temperatures as much as 90°F higher than predicted for pure amorphous silica (Gallup, 1989b), manipulating process parameters alone was not successful in inhibiting iron silicate scaling.

Based on pilot scale tests at Brawley and Salton Sea, Unocal patented the discovery that acidification of the brine by .3 to .5 pH units and injection above 360°F could inhibit the kinetics of the iron silicate scale-forming reaction (Jost and Gallup, 1985).

Brine Treatment The pH modification process employed in the Salton Sea Unit 2 RPF treats over 1,000 klbs per hour of brine (Figure 2). At the outlets of the wellhead separators, 31 wt% hydrochloric acid diluted 1:10 with hotwell condensate is injected into the brine through a patented mixing system (Gritters, et al., 1986). At the acid mixing point, the pH of the brine is reduced from 5.9 to about 5.0 by injection of 100 - 120 ppm HCl (100 % basis).
The acidified brine flashes to standard pressure (about 110 psig) in a large horizontal separator. Brine from this Separator is pumped to the injection wells. Untreated injection brine typically exhibits a pH of about 5.3, while acidified injection brine is maintained at a pH of about 5.0. Plant operators select the injection well tubing and tubing/casing annulus combination that keeps the brine just above the flash pressure at the wellhead.

Technology Application PH-modification is a simple process that is well-suited to changes in flowrate, making it attractive for "peak generating" flexibility.

Although there is only a small change in the measured pH of the brine, there is a enormous increase in its corrosiveness. The higher cost of corrosion-resistant alloy construction may be justified by the cost savings from elimination of several vessels, tanks, pumps, and the solids dewatering and solids utilization equipment. Similarly, the high operating costs consequent to acid use may be offset by the elimination of the solids utilization program (Hoyer 1990), and other challenging processes.

H₂S Abatement

Operating permits for Salton Sea Unit 2 require the abatement of hydrogen sulfide emissions. This is being accomplished with Unocal's new, patented, liquid phase oxidation process (Gallup, 1991).

Background The most common abatement systems used in the geothermal industry are incineration and liquid redox sulfur recovery processes (Weres, 1984). The liquid redox processes are used to abate both primary and secondary emissions. Gas streams (primary emissions) are abated by absorbing the H₂S in the vent gas and oxidizing it with the oxygen in air to form elemental sulfur and water. Secondary emissions from sulfide-laden cooling tower circulating water are also controlled by adding oxidizing agents to the water that convert sulfide to sulfur (Dalrymple, et al., 1989).

In 1987, Unocal discovered that the addition of chlorine and bromine stabilized biological oxidizing, "BIOX", agents to cooling tower circulating water entirely abated the secondary emissions by converting dissolved sulfide to a soluble sulfate salt in ratios hundreds of times less than stoichiometric amounts. These oxidizing agents appear to acid-catalyze the reaction of sulfide to sulfate with only a minor consumption of oxygen in the cooling water. In pilot testing, researchers developed a primary abatement method to scrub and abate the vent gas as well, using the circulating water.

The "BIOX" Process Condensate from the hotwells of the turbine's surface condensers is the makeup water for the cooling towers (Figure 3). No elemental sulfur solids are precipitates as over 95% of the dissolved sulfide oxidizes to sulfate.

![Figure 3](image)

The off-gas from the condensers is compressed and bubbled into the circulating water at the bottom of the vertical risers into the cooling tower. Typically, 85% of the H₂S in the non-condensable gas converts to sulfate in the neutral pH water. Only the "BIOX" agent is required to abate the primary emissions. However, the circulating water tends to be made acidic as a consequence of scrubbing a fraction of the CO₂ in the vent gas. To control pH at Unit 2, lime is added to the circulating water. The lime also increases calcium hardness for corrosion control since the water is naturally deficient in calcium.

Performance Mass balances show an abatement of 90-95% of the total H₂S sent to the cooling tower in the makeup and the off-gas by employing this novel process. Therefore, over 200 lbs per day of H₂S is converted to soluble sulfate by adding only 16 lbs per day of "BIOX" agent and 120 lbs per day of lime to the cooling tower circulating water. Waste disposal is also simple since the sulfate produced in the cooling water is blown down and pumped to an injection well.
Three basic techniques were employed to minimize the design and construction costs. Secondly, two turbines were installed to capture energy that was being processed, but not used. Finally, designs were pursued that minimized operating expenses, including parasitic loads, labor, and unexpected shutdowns and unit trips.

Minimized Design and Construction Costs

The primary means of reducing the design and construction costs was the use of overlapping design, construction, and startup schedules. Additional construction savings were obtained by the use of skid-mounted equipment.

Scheduling

Unit 2 reached commercial operation within eighteen months of the start of design by integrating and overlapping the design, construction, and startup efforts. (Figure 4) The detailed design of Unit 2 began in July, 1988 and finished in October, 1989. However, construction started in December, 1988 and the first commissioning and startup was in February, 1990.

In the later stages of construction, as each system was completed, the checkout, flush, functional testing and commissioning was started. The Unit 1 turbine was brought back on-line from the new control room in December, 1989, after a one month shutdown. The first Unit 2 turbine came on-line in February, 1990, and the last in April. The B10X H2S abatement system started-up in April, 1990.

Reduce field construction

Construction time and expense were reduced by using prefabricated equipment wherever possible. This effort resulted in earlier revenues and reduced interest during construction.

The three Unit 2 turbines and lube-oil units were fabricated in a shop and skid mounted. Skids minimize the amount of field-fabrication pipe and simplify electrical and instrumentation connections, since motors and instruments were pre-mounted and wired.

Two-thirds of the motor control centers (MCCs) were shipped fully wired in stand-alone buildings. The vendor supplied the project electrical drawings as well, reducing engineering time.

Other successful efforts to pre-fabricate equipment included shop-fabricated pipe spools, the 92kV switchgear, and the LP turbine gas-ejector system.

Unit Efficiency

The driving principle behind much of the Unit 2 design was to more effectively use the resource that was already supplying Salton Sea Unit 1. Untapped energy was available from both high pressure and low pressure steam. The process design for the pH-mod RPF also lent itself to recovering additional high pressure steam energy.

High Pressure Steam

The pressure control valves on Unocal's wellhead separators typically dropped the steam pressure from over 300 psig to about 120 psig. The energy wasted in this expansion is now captured by the turboexpander, described in Part I. The turboexpander uses the steam from both the Unit 1 and Unit 2 wellhead separators to produce 3 to 3.5 MWe of power.

The turboexpander is very cost-effective. The capital cost is low because there is no condenser, gas ejector, or cooling tower. The machine itself is simple, so an overhaul only takes a few days. Finally, nearly all the power produced is available for export since the only parasitic load is the lube oil pumps. Overall, the installed and operating cost per kw-hr for the turboexpander is only a fraction of the cost of a condensing turbine.

Low Pressure Steam

Unit 1 was originally built primarily to demonstrate the crystallizer-clarifier brine-handling technology, so for simplicity, the turbine has a single inlet pressure. As
such, the low pressure steam was vented to atmosphere, representing an unused energy source. The Unit 2 project retrofitted Unit 1 with a single entry, single pressure turbine having a design steam chest pressure of 15-22.5 psig. (All other Salton Sea development since Unit 1 has used the low pressure steam flash in a dual pressure turbine (Newell 1989).)

The use of the turboexpander and the LP turbine at Unit 1 increased the energy conversion efficiency by 25%.

Operating Costs

Profitability at Units 1 and 2 requires holding operating costs to a minimum. This includes not only the day-to-day expenses, but also losses in production capacity, resulting in lost or curtailed generation.

**Availability** Fully operational equipment is the key to profitability and failure prevention is a critical means to ensuring availability in a scaling and corrosive environment, such as the Salton Sea KGRA. To reduce failure rates, Unocal uses alloys or large corrosion allowances in highly corrosive areas such as the acid injection spools and wellhead lines.

The material of choice is determined by evaluating present worth costs. This is initial capital and replacement cost in present dollars, based on measured corrosion rates from field testing. Materials used include heavy-wall carbon steel, 316 and duplex stainless steels, nickel based alloys, and titanium alloys. Each material has a different useful life in the various temperature and pressure regimes. Unocal's patented Beta-titanium production well casing is one such example where the higher cost of alloy is justified by higher well integrity and lower workover costs (Love, et al., 1988).

The expense of redundant alloy equipment was reduced by using different materials of construction for the "standby" components. For example, the main pump train in the Unit 2 RPF is alloy, but the standby injection train is carbon steel. The standby train is only used until the alloy pump is fixed and put back in service.

**Control system** Electronic single-loop controllers and manual operation required three to four operators in two control rooms to run Unit 1 from 1981 to 1989. However, one goal of the Unit 2 project was to operate the entire Unit 1 and 2 complex with no more than five operators per shift even though there would be three additional turbines and a new pH-mod resource production facility. The key to accomplishing this was the control system.

One lead operator uses a distributed control system (DCS) to monitor and control both RPFs and all four PGFs. The board operator handles the ordinary process, turbine, and generator controls with four roving operators to troubleshoot and take care of manual operations. Two of the turbines are controlled with dedicated Woodward 505 computer-based governors. The older turbines use DCS-generated setpoints to mechanical governors to control loading.

Some of the functions implemented on the DCS include remote start/stop for all pumps, turbine pressure control or setpoint changes, and VAR control. Other advanced programming uses an acid pump feedback signal to control the acid injection rate, based on the brine flow rate, so that the acid concentration (in ppm) is held constant.

**Process Optimizations** Operating costs can also be reduced in the selection of the particular process used at the facility. For example, direct level control of the Unit 2 SP Separator is accomplished with A/C variable speed drive on the main injection pump. Lower pump speeds reduce the house load, and pump wear.

Turbine nozzle scaling can decrease turbine capacity or efficiency. Although steam washing quenches a portion of the available steam. Unocal washes the HP, SP, and LP steam upstream of the scrubbers with hotwell condensate, reducing steam chlorides to the turbine to about one ppm (Figure 5). A demister in front of each axial flow condensing turbine provides further steam polishing.

**Figure 5**

*Typical Steam Wash Process*
Salton Sea Unit 2 is a combination of proven methods and new techniques that has performed above expectations.

**Previous Experience**

Much of the technology used at Unit 2 had been tested and proven at Salton Sea Units 1 and 3 over the previous nine years, and at Brawley Unit 1 for five years.

**Used Equipment**

In 1985, the Unocal/SCE (Southern California Edison) development project at Brawley ended. Unocal acquired the power plant and stored it along with the pH-mod resource production facility equipment until it found application as part of Unit 2. Used equipment requires a tremendous inspection and supervision effort to be brought back on-line, even if it was working well when it was decommissioned.

Many of the problems in reusing the old equipment were damages that were not found until a point in the project where it was too late to replace the damaged parts. Instead the damages had to be fixed on short notice, often during the trouble-shooting and startup stages, which caused cost increases or delays. Some examples of these unexpected challenges were incomplete restoration of the lube oil coolers, damaged motor control centers, and corroded turbine casing seals. If similar work is ever required in the future, more up-front engineering and maintenance evaluation will increase the effectiveness of reused equipment.

**New Technologies**

Three new technologies are operating reliably at Unit 2. The "BIOX" H₂S abatement process started up almost flawlessly, but the turboexpander and the pH-modification process each had idiosyncracies that showed themselves during startup.

**Turboexpander**

Unocal expected the Rotoflow turboexpander to be a profitable investment, but it was also viewed as a research and development effort. Some problems were expected during the first few months that would require retrofit projects. The Rotoflow was not operating to full potential until September, 1990.

The most serious problem was the fatigue failure of an internal alignment bolt that fell into, and fatally damaged, the turbine. Since a spare center section was available, the turbine was back up and running within 4 days.
PART IV - CONCLUSION

Unit 2 is an integrated facility with Salton Sea Unit 1, that came on-line 18 months after the start of detailed design. With the addition of Unit 2, the complex has increased output from 10 MW to over 30 MW. This increase was accomplished both by adding a second Resource Production Facility and by increasing the resource utilization efficiency at Unit 1 by 25%.

By lowering the brine pH with acid, Unocal's new pH-modification process at the Unit 2 RPF successfully controls brine scaling. Unit 1 still employs the crystallizer-clarifier process for scale control. The side-by-side comparison of the two units will help determine the scale-control process for Unocal's future projects at the Salton Sea KGRA.

REFERENCES


