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Workshop on environmental-control technology for the Geysers-Calistoga KGRA

John H. Hill – Technical Editor
Paul L. Phelps – Project Manager

January 28, 1980

Lawrence Livermore Laboratory

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LAWRENCE LIVERMORE LABORATORY
University of California • Livermore, California • 94550

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FOREWORD

At the request of the Department of Energy's Division of Environmental Control Technology, Lawrence Livermore Laboratory (LLL) organized a workshop on environmental control technology applicable to The Geysers-Calistoga known geothermal resource area (KGRA). Approximately 80 experts in well drilling, geothermal operations, noise abatement, hydrogen sulfide abatement, power plant operation, materials, systems design, systems control, and legal regulations gathered to discuss ways to prevent, control, and mitigate undesirable environmental impacts caused by geothermal development at The Geysers.

The workshop, held at the Oakland Hyatt House, October 11 and 12, 1978, was funded under programs managed by Douglas W. Boehm, Division of Environmental Control Technology, Office of Environmental Compliance and Overview, under the Assistant Secretary for Environment, DOE. It was part of a series of workshops funded by the Assistant Secretary for Environment. Cosponsors were the Geothermal Environmental Overview Project (GEOP) of LLL and the Geothermal Resources Impact Project Study (GRIPS). GRIPS is a joint powers agency of Napa, Sonoma, Lake and Mendocino Counties with the California Energy Commission and DOE as ex-officio members.

Preparations, logistics, and liaison for the workshop were provided by the Geothermal Resoures Council (GRC) under executive director David N. Anderson by subcontract from LLL. The GRC is a multidisciplinary non-profit organization whose purpose is to promote the development of geothermal energy.

CONTENTS

ABSTRACT

This report is the proceedings of six work groups that discussed techniques to prevent and abate noise, hydrogen sulfide emissions, and accidental spills of chemicals and geothermal wastes at The Geysers-Calistoga KGRA. Problems associated with well completion and production, and with systems, components, and materials, and their effects on emissions were also discussed. The comments and recommendations of the work groups are included in the proceedings.

A brief summary of the recommendations from the workshops is as follows:

1. Develop a coating to protect the well casing from erosion during air drilling.
2. Develop better techniques for cement emplacement.
3. Set up a program to test candidate cements under simulated and actual operating conditions.
4. Develop a down-hole safety valve to use on wells installed in landslide areas.
5. Improve knowledge of H_2S partitioning in condensers.
6. Encourage development of alternative methods of H_2S abatement.
7. Install berm and sump systems to contain spills on all power plants.
8. Develop automatic control systems for the liquid portion of fluid handling systems.
9. Strengthen the Liquid Waste Hauler Law to include equipment checks, driver certification, and fines for substandard or defective equipment.
10. Develop a muffler for steam venting at the wellhead.
11. Develop a dynamic computer model to aid in designing automatic controls for steam-gathering systems.
12. Allow time to develop and test control processes before changing regulations.
13. Carefully weigh the hazards and benefits introduced with abatement processes.

INTRODUCTION

The purposes of the workshop were to review existing technology, evaluate new ideas, and plan the development of techniques, systems, materials, and hardware for future use in preventing, controlling, or mitigating undesirable environmental impacts of geothermal development in The Geysers-Calistoga KGRA. Planning to meet future problems was emphasized.

A steering committee (Appendix A) suggested topics for the workshop and prepared a list of participants.

The workshop was attended by about 80 experts (Appendix B) in well drilling, geothermal operations, noise abatement, hydrogen sulfide abatement, power plant operation, materials, systems design, systems control, and legal regulations. The first morning included a welcome by Dave Anderson, Geothermal Resources Council, an introduction by Paul Phelps, LLL, and the keynote address by Suzanne Reed, California Energy Commission. The attendees then split into six work groups (Appendix C) according to their areas of expertise. Work groups were kept small (10 to 20 persons each) so that ideas could be informally presented. People with expertise in several areas were encouraged to move from one work group to another during the second day of the workshop. At the conclusion of the workshop, each chairman submitted a written summary of his group's proceedings, comments, and suggestions.

In this workshop, we solicited the advice and opinions of people expert in their field. Where possible, these have been preserved intact as received in the summaries from the work groups. However, in the interest of more complete coverage, the editor has supplemented the chairmen's notes with additional information from publications or private conversations and is solely responsible for any errors that may result.

Specific comments and recommendations together with sources of additional information are included at the end of the proceedings. Additional comments and recommendations received during discussions with individuals or small groups outside the workshop sessions are as follows:

Regulations are a moving target. This comment was particularly frequent when the topic was abatement of noise and H_2S emissions. At best, bench and small pilot-scale tests serve only to screen out poor performers among candidate control techniques. Actual performance of a control technique depends to a large extent on fluid chemistry, fluid dynamics, systems design, and systems dynamics. Therefore, a full scale installation is needed to test the performance of a given control technique. These installations are expensive and may require one or two years lead time for design and installation. In addition, from one to five years may be needed to properly evaluate the technique's performance and effect on other components of the geothermal system. Short-term (less than five years) changes to more stringent regulations can easily leave the steam producer or power plant operator with an obsolete--but expensive--piece of almost new junk.

The degree of hydrogen sulfide abatement required needs to be carefully evaluated to justify abatement costs and additional hazards caused by abatement chemicals. We can expect truck accidents that cause accidental spills. Transporting materials to and from Geysers Units 1 through 12 involves trucking over narrow mountain roads with sharp curves and steep grades. These roads are particularly hazardous in the winter when they are slick with rain, snow, or ice. Many of the chemicals used for H_2S abatement would harm the environment, particularly if they were spilled during a rainstorm when cleanup would be difficult. In this respect, spills of 50% sodium hydroxide solutions present a special hazard. They would be difficult to contain and clean up even in the dry part of the year. A spill of a truckload (about 5000 gal) of this strong caustic during a rainstorm would almost certainly be washed into adjacent streams where it could be expected to eliminate much aquatic life for a considerable distance downstream. Also, any animal which tried to drink the contaminated water could be seriously injured.

Some degree of H_2S abatement is required. The average concentration of H_2S in steam at The Geysers exceeds 200 ppm. If the noncondensable gas stream from a power plant was vented directly to the atmosphere with no dilution or abatement, toxic limits (about 20 ppm) for H_2S would be exceeded at the vent and could also be exceeded in the adjacent work areas under adverse atmospheric conditions. However, it should be possible to reduce emissions well below toxic limits without using some of the more hazardous chemicals in current use.

At concentrations below 20 ppm, H_2S is a nuisance primarily because of its odor. The California ambient air standard (0.03 ppm for H_2S emissions averaged over an hour) is based on the odor threshold. Because of the hazards associated with chemicals needed to attain such a high abatement efficiency, there seems to be a need to evaluate the degree of abatement actually needed in remote areas (such as those occupied by Units 1 through 12). Does eliminating the odor nuisance in these remote areas justify the cost and hazards of the abatement chemicals?

In settled areas (such as Cobb Valley and Anderson Springs), the odor nuisance is probably unacceptable. However, these areas are at a lower elevation where the terrain is relatively gentle, roads are much better, and snow melts rapidly. Therefore, accidental spills are less likely and easier to clean up when they do occur.

WELL COMPLETION AND PRODUCTION

Chairman-Louis E. Capuano

This work group considered problems associated with geothermal wells from drilling through production. The four problem areas that seem to need additional attention are

- erosion of drill casing and drill string during air drilling,
- emplacing cement,
- compatability of cement with the geothermal environment,
- well failure caused by landslides.

During the initial stages, geothermal wells at The Geysers are drilled with conventional drilling muds. However, when the well reaches a depth where high temperatures (120^{o}F) begin to cause the mud to lump, cake, and lose viscosity, air drilling techniques are used. Drill cuttings in the air stream produce a sandblasting effect that erodes the drill string and casing. A protective coating would reduce this erosion and result in a more competent casing to help prevent failure through the life of the well.

Cement should be emplaced so as to provide a good bond between the casing and the formation to ensure the integrity of the well. The low pressure reservoirs found at The Geysers do not have the hydrostatic head to support a sufficient column of liquid cement during emplacement. As a result, the cement sometimes does not make a good seal around the casing and there is also a considerable loss of cement in cracks and fissures. Pockets of fluid (water or mud) may be trapped between the casing and the formation during cement emplacement. Later, when steam is allowed to flow in the well, these fluids can vaporize and crack the cement.

Research is needed to establish better techniques for placing cement in the annular space between the casing and the formation. The development of mechanical devices to achieve better displacement is needed. Devices presently used in the oil industry may not work on geothermal wells without some modification and development. Also, preflushing techniques might be developed to limit lost circulation, remove pockets of fluid, and ensure a better bond between the pipe and formation.

The high temperatures encountered in geothermal wells cause cement problems. It is difficult to cool the system before cement placement. Therefore, high concentrations of retarders are needed to keep the cement from setting before it is properly emplaced. These retarders sometimes keep the cement from curing properly. During curing, the high temperatures may prevent formation of the proper crystalline structure. Also, water may boil out, leaving dry cement, void spaces, or steam pockets. After the cement is set, thermal cycling can cause failure because the casing, cement, and adjacent formation have different coefficients of expansion.

Cement failures could cause loss of geothermal fluid into the adjacent formation. As a result, local aquifers (not common at The Geysers) could be contaminated. In a worst case, cement failure might cause a well blowout.

A good cement for geothermal applications should meet the following criteria:

1. It should be easy to emplace.
2. It should be compatible with the geothermal environment.
3. It should have a low permeability.
4. It should be durable.
5. It should have high compressive strength.
6. The cost should be reasonable.

Work is needed to develop a cement that will meet these criteria.

In the past, most blowouts in producing wells at The Geysers have resulted from landslides. A program is now under way to locate new wells in nonslide areas and to phase out the old wells in slide areas. Another approach to controlling blowouts in slide areas involves developing a down-hole safety valve to shut the well in completely if the casing is cut by a landslide. This valve would have to be designed to withstand corrosion, erosion, steam temperatures, pressures, and flow rates, and still maintain a seal when required. It would be placed in the well below the slide plane (about 500 ft deep) and would have to close automatically if a landslide cut the casing.

<u>Recommendations:</u>

1. Develop a coating to protect the well casing from erosion during air

drilling.

2. Develop better techniques for emplacing cement to ensure a good bond between the casing and the formation. The use of additives might help solve placement problems and minimize lost circulation.

3. Establish better cement bond logs to analyze cement jobs.

4. Conduct bench tests under simulated conditions of temperature, pressure, and chemical environment to evaluate all forms of polymer and plastic cements as well as the present type of Portland cements.

5. Set up a program to test all promising cements in the field, in the actual environment where they will be used. Developers could provide a test facility for this.

6. Develop a down-hole safety valve to use on wells installed in landslide areas.

Additional Information

Brookhaven National Laboratory publishes a quarterly progress report entitled Cementing of Geothermal Wells that describes work in this area sponsored by DOE-Division of Geothermal Energy. Other useful references include:

Economic Assessment of Polymer Concrete Usage in Geothermal Power Plants, Brookhaven National Laboratory, Upton, New York, BNL-50777, November 1977.

J. P. Waters, D. E. Pyle, and L. T. Waters (Union Oil Co. of Cal.) Performance of Oil-Well Cementing Compositions in Geothermal Wells, Society of Petroleum Engineers 53rd Technical Conference and Exhibition, Houston, Texas, Oct. 1-4, 1978.

A. L. Sug Roberts, Pipe Fatigue in San Salvador or Managua, W-K-M Wellhead, Denver, CO. (303) 756-9449

Drilling and Operating Geothermal Wells in California, California Division of Oil and Gas, Publication No. PR 75, Sacramento, CA (1978).

HYDROGEN SULFIDE ABATEMENT

Chairman-Upstream Abatement--Gordon W. Allen

Chairman-Downstream Abatement--Neil A. Moyer

This subject was covered by two work groups. The first considered processes for abating hydrogen sulfide in the steam supply systems upstream from the turbine. The second considered processes for abating hydrogen sulfide emissions downstream from the turbine.

Upstream Abatement

G. W. Allen--Pacific Gas and Electric Co. (PG&E), presented background information concerning PG&E's participation in developing hydrogen sulfide abatement systems including the burner-scrubber, the Fe catalyst system, the deuterium corporation process, and the EIC-copper sulfate process.

For optimum control of H_2S emissions, upstream processes have these advantages over downstream processes:

1. They continue to operate even when the plant is off line.
2. They can be located near the steam source and thus control emissions from all downstream vents.
3. Because they remove H_2S from the steam, they should reduce corrosion caused by H_2S in downstream hardware.
4. They usually involve a scrubber system that also removes some of the entrained materials such as ammonia, boron, particulates, and water droplets from the steam.

Some disadvantages of upstream processes are:

1. They may degrade the steam.
2. They may introduce chemicals or reaction products from the treatment processes into the steam.

The variability of the steam supply must be considered in designing upstream abatement processes because the steam quality and chemistry may vary considerably with time, the well source, and the level of power plant operation. In steam supply networks equipped with crossover systems designed to minimize steam stacking, a part of the steam supply may be switched from power plant A to power plant B in a short period of time after plant A is shut down for a scheduled or unscheduled outage. Thus, the characteristics of the steam entering an H_2S abatement unit in the line to plant B could change considerably. Operating conditions in the abatement unit must be changed automatically; this requires reliable instruments to detect and signal the necessary adjustments.

The deuterium proess was discussed briefly. A pilot plant removed 95% of entering H_2S in a field test conducted at PG&E's Unit 7. This is a proprietary "black box" process and we have no information on operating parameters.

Warren Smith--Union Oil Company, described throttling controls used on wells during power outages to reduce emissions and conserve the resource. Since 1972, 10-in. Fischer Vee-ball valves have been used in this application. These valves are now operated manually but they can also be used with automatic controls, which would provide quicker response and better control.

Union has also been experimenting with a scrubber system to remove water and particulates from the steam. In this system, water is injected into the steam upstream of a separator. The injected water, together with water droplets present in the steam particulates, is then separated from the steam in the separator. Results to date look promising and work on this system is continuing.

Investigations into the use of solid sorbents such as zinc oxide and iron oxide to remove H_2S from steam were also described. In general, these materials were not very satisfactory because of problems associated with regenerating the sorbent and with reaction products that coat the surface of the sorbent.

The use of sodium hydroxide and hydrogen peroxide to control hydrogen sulfide during air drilling was also described. The sodium hydroxide and hydrogen peroxide solutions are injected into the blooey line where they react with the hydrogen sulfide as follows:

$$H_2S + 2\ NaOH + 4\ H_2O_2 = Na_2SO_4 + 6H_2O$$

Over 90% of the hydrogen sulfide is routinely removed from the blooey line effluent (drill cuttings and fluid waste from drilling).

Glenn Coury--Coury and Associates Inc., described a selective condenser-reboiler system that would separate the noncondensable gases, including H_2S, from the steam. Additional treatment would be required to abate the H_2S in the noncondensable gas. An experimental unit to investigate H_2S separation efficiency, fouling factors, recycle buildup, and heat transfer coefficients is scheduled to start operating in November 1978 at PG&E's Unit 7. Some metallurgical studies will be conducted in parallel.

Ray Long--Dow Chemical Co., described a process developed by Dow to remove H_2S from sour gases with NaOH. This process involves a simple in-line contactor operating on a minimum-residence principle to remove H_2S selectively from CO_2 mixtures.

He also described techniques to oxidize H_2S with O_2 and Cl_2.

Charles T. Li--Battelle Pacific Northwest Laboratory, described his work on removing H_2S from steam by catalytic oxidation on solid absorbents. Activated charcoal is the best absorbent found. Sulfur collects on the charcoal and is extracted with a solvent such as carbon disulfide, ammonium sulfide, or dichloro-methane. The steam used in these experiments did not contain boron to simulate Geysers steam. The process requires superheated steam and probably has limited applications at The Geysers, where free water is frequently present in the steam at random intervals. Its most probable application would be in steam stacking during power plant outages.

Alvin Samuels--Ironite Products Co., showed that high-surface-area iron oxide sponge reacts rapidly and completely with H_2S. This material would probably be used on a once-through basis and therefore might involve high costs (about \$1/lb of H_2S treated). It appears best suited for steam stacking and well completion requirements.

F. Brown--EIC, Inc., described the status of an ongoing 100,000 lb/hr demonstration plant using the EIC-copper sulfate process at Unit 7, The Geysers. This plant will involve a fully integrated operation designed to obtain information on long range operating factors such as trace element buildup, regeneration efficiency, the effect of cleaned steam on power plant components, and data for scale-up (including materials evaluation).

In this process, the steam contacts a copper sulfate solution in a scrubbing tower. Hydrogen sulfide in the steam reacts with the copper sulfate solution as follows:

1) $CuSO_4 + H_2S = CuS + H_2SO_4$

2) $2CuSO_4 + 2H_2S = Cu_2S + S + H_2SO_4$.

Both the cupric sulfide (CuS) formed by reaction 1) and the cuprous sulfide (Cu_2S) formed by reaction 2) are insoluble solids. These solids are either separated from the solution and roasted in air or leached with oxygen under pressure to regenerate copper sulfate. The sulfuric acid generated in reactions 1) and 2) may be partially neutralized by ammonia in the steam, but will probably require additional treatment with some reagent such as calcium carbonate, ammonia, sodium hydroxide, or sodium carbonate to be completely neutralized.

This is the process in the most advanced stage of development for removing hydrogen sulfide from steam upstream from the power plant. In addition to being an upstream process, it has the advantage that the primary reagent ($CuSO_4$) can be regenerated on site. Therefore, the need to transport chemicals to the site is minimized. A disadvantage is that copper ion from the copper sulfate solution and free sulfur from reaction 2) may become entrained in the steam and be swept into the turbine. The copper ion could plate out on ferrous metals to produce a bimetallic couple which would cause electrochemical corrosion and lead to early failure of such components as turbine blades. The free sulfur might plate out as the steam cooled while passing through the turbine and decrease the efficiency of the turbine blades. These factors will be investigated while the demonstration plant is operating.

<u>M. Tolmosoff--Northern Sonoma County Air Pollution Control District,</u> expressed concern about control over H_2S emissions from steam stacking during a power plant outage. The resulting discussion concerned how and when a power plant outage occurs, the problems in speeding response time, the predominate use of manual controls for well throttling, and auxiliary treatments to remove H_2S. It was the consensus of the group that the most promising approach for better control involves refining steam throttling procedures together with chemical treatment (such as the use of NaOH and

H_2O_2).

Steam throttling involves both the steam supply system and the power plant configuration. Where possible, power plant sites are planned so that two independent units can be located on the same site with interconnected steam supply systems. Thus, when one unit is shut down, the steam supply to both units can be throttled down and sent to the operating unit. Optimum use of this approach will require some degree of field unitization with a designated operator when more than one steam supplier is involved.

Downstream Abatement

Oleh Weres--Lawrence Berkeley, Laboratory: Downstream from the turbine, there are two effluent streams containing hydrogen sulfide--the noncondensable gas stream and the steam condensate. Partitioning H_2S between the condensate and the noncondensable gases depends on several factors including:

- The concentration of noncondensable gases in the steam. As the noncondensable gas fraction increases, the amount of H_2S swept through the system will tend to increase.
- The chemical composition of the noncondensable gases. The concentrations of H_2S, NH_3, and CO_2, are the most critical. As the H_2S concentration increases, more will tend to be swept through the system with the other noncondensable gases. As the ratio of NH_3/CO_2 increases, the condensate will become more basic and H_2S will dissolve in the condensate. The following data from power plants equipped with direct contact condensers illustrate this.

	H_2S (ppm)	NH_3 (ppm)	CO_2 (ppm)	H_2S split (NC gas/ condensate)
The Geysers	200	200	4,000	30/70
Cerro Prieto	2000	100	12,000	70/30

- The flow rates. At high steam flow rates, there will be less time for equilibration and more H_2S will be present in the noncondensable gases.
- The condensate temperature. As the temperature increases, the solubility of H_2S decreases.
- The type of condenser and its design. In direct contact condensers

used on Geysers Units 1-11, about 30% of the H_2S is in the noncondensable gas fraction and about 70% dissolves in the condensate. Most of the H_2S is expected to remain in the noncondensable gas fraction from new units equipped with surface condensers. However, partitioning calculations can be highly misleading because they are so very dependent on condenser design and the physical chemistry of the constitutents.

Partitioning H_2S between the condensate and noncondensable gases is a key factor in selecting processes for abating H_2S emissions downstream from the turbine. In particular, work is needed to develop, evaluate, and validate a model for H_2S partitioning performance in surface condensers so that various design parameters can be evaluated.

Garratt Sharp--Pacific Gas and Electric Co., described PG&E's experience with the iron catalyst system and recent work using hydrogen peroxide and sodium hydroxide to supplement the iron catalyst system.

In Geysers power plants equipped with direct contact condensers, about 70% of the H_2S dissolves in the condensate with the remainder exhausting in the noncondensable gas stream. Because the condensate is used as cooling water, the H_2S is stripped out into the air stream in the cooling tower. The Fe catalyst system is a wet oxidation process designed to treat the H_2S in the condensate. This system involves a wet oxidation process which incorporates the following reactions.

1) $H_2S + OH^- = HS^- + H_2O$
2) $HS^- + 2Fe^{+3} + OH^- = S + 2Fe^{+2} + H_2O$
3) $Fe^{+2} + HS^- + OH^- = FeS + H_2O$
4) $Fe^{+3} + 3\ OH^- = Fe(OH)_3$
5) $4\ Fe^{+2} + O_2 + 2H_2O = 4\ Fe^{+3} + 4\ OH^-$

Hydrogen sulfide dissolves in the slightly basic solution to form bisulfide ion as shown in reaction 1). The bisulfide is oxidized to free sulfur by ferric ion as shown in reaction 2). If hydrogen sulfide is present in excess of the stoichiometric amount of ferric ion, the excess can react with ferrous ions to form ferrous sulfide as shown in 3). A large excess of hydrogen sulfide will overload the system and significantly decrease its efficiency.

Solids containing sulfur, ferrous sulfide, and ferric hydroxide are formed by reactions 2), 3), and 4). These solids form a sludge that tends to collect on surfaces in the cooling tower and thus cause plugging and impair heat transfer. These solids must be removed continuously and hauled to an approved disposal site. Ferric ions are regenerated by the reaction of ferrous ion with oxygen from the air in the cooling tower as shown in 5). However, it is also necessary to add ferrous sulfate to replace the iron compounds removed as sludge. The total amount of ferric iron available for reaction is limited by reaction 4) and by the solids-carrying capacity of the system.

When this system was first used on Unit 1, better than 90% abatement of H_2S was achieved. Initial results at Unit 11 were also good. Then, the concentration of H_2S in the steam increased from 100 ppm to 300 ppm, the system was overloaded, and abatement dropped from about 85% to 40-60%.

During the last five months, PG&E has been experimenting with the addition of hydrogen peroxide and sodium hydroxide to supplement the Fe catalyst. In this system, reactions 1) and 2) shown above occur as in the unsupplemented system. The supplemental H_2O_2 reacts as follows:

6) $HS^- + H_2O_2 + H^+ = S + 2H_2O$.

Sufficient H_2O_2 is added to consume the H_2S that would otherwise overload the system. In this reaction, iron acts as a catalyst to increase the reaction rate.

At Unit 11, almost 100% abatement was achieved using 600 lb/hr of H_2O_2 in the presence of 80-100 ppm of Fe. The steam contained about 300 ppm of H_2S and the system operated at a pH of about 8.0. At higher pH's the consumption of H_2O_2 increased considerably because the following reaction predominates.

7) $HS^- + 4H_2O_2 = SO_4^{-2} + 4\ H_2O + H^+$.

This reaction consumes four times as much H_2O_2 as is required for reaction 6). Injecting the H_2O_2 into the hotwell of the condenser allows about 20 seconds of residence time for the reaction to take place before the condensate arrives at the cooling tower.

Equipment to supplement the Fe catalyst system by adding H_2O_2 and NaOH is now being installed at Units 3, 4, 5, and 6 in addition to Unit 11.

Cliff Black--Ralph M. Parsons Co., described the Stretford process being installed at Geysers Unit 15. In this process, H_2S is dissolved in the Stretford solution which is maintained at a pH of about 8.8 by the addition of sodium carbonate. Vanadate in the solution oxidizes the dissolved H_2S to free sulfur. The reduced vanadate is then regenerated by oxidation with air in the presence of anthraquinone disulfonic acid. The sulfur is separated from solution and converted to a 99.9% pure cake which can be sold.

The process operates well over a wide temperature range ($70^{o}F$ to $120^{o}F$). At temperatures below $70^{o}F$, the reoxidation rate for vanadium may be too slow for most efficient operation. At temperatures above $120^{o}F$, the rate of sulfur solubilization begins to increase significantly and thus reduces the efficiency of sulfur separation. The process is flexible to changes in H_2S concentration and will accept a temporary overload with relatively little loss of efficiency. However, depending on the design of a particular system, major modifications may be needed for significant long term changes in H_2S concentration.

A small purge of Stretford solution is required to remove sulfates and thiosulfates produced by side reactions in the process. This purge will be injected underground at The Geysers and should not constitute an environmental hazard except in the case of accidental spills. Sulfur produced in the process is about 99.9% pure and does not present a disposal problem because it can be sold. Some Stretford solution could escape as droplets in the drift from the cooling tower. If so, it could have detrimental effects on plants in the immedidate vicinity.

This process has previously been used in petroleum refineries where the usual requirements allow no more than 10 ppm of H_2S to be discharged to the atmosphere in the tail gas. Parsons designs for no more than 5 ppm H_2S in the tail gas and expects no more than 1. Outages in the process are caused primarily by failures in pumps and blowers that can be replaced readily by spare units. The reliability of the Stretford scrubber is very high.

The Diamox process used in Japan to scrube coke oven gas was also described. This process, which uses recycled liquor fed to a Claus unit, consumes a lot of steam. It requires a large amount of equipment but cannot achieve a low level of H_2S emissions.

<u>Konrad Semrau--SRI International,</u> discussed the Fumaks and Takahax processes used in Japan to remove H_2S from coal gas.

The Fumaks process incorporates a basic scrubber with wet oxidation. Air is used to oxidize H_2S to free sulfur in the presence of a catalyst which consists of a nitrated aryl compound such as picric acid.

The Takahax process incororates a basic scrubber using ammonia as the base with wet oxidation. Air is used to oxidize the H_2S to sulfate with sodim napthoquinone sulfonate as a catalyst. Ammonium sulfate is produced for sale as a byproduct.

He also discussed the burner scrubber and the use of oxidizers such as Cl_2 and SO_2 to replace H_2O_2. Additional research would be needed to determine the feasibility of such oxidants because it is difficult to control end products. Also, reaction rates and stoichiometry are not well known.

Harry Castrantas--FMC Corporation, discussed using hydrogen peroxide to abate hydrogen sulfide in steam condensate and well drilling operations.

Injecting H_2O_2 into steam condensate oxidizes the sulfide within 15 seconds at 50^oC in the presence of trace amounts of soluble iron salts (0.1 mg/l to 2 mg/l). The product of the reaction under acid and neutral conditions is predominately colloidal sulphur. Under alkaline conditions (above pH 8.5) the predominant product is sulfate. Mole ratios of 1/1 to 1/4 of sulfide to H_2O_2 are needed for essentially complete reaction. THe lower mole ratios apply under acid or neutral conditions; the higher mole ratios for alkaline conditions.

A similiar process has been applied with modifications in treating PG&E Unit 11 condensate (direct contact condenser). The H_2O_2 is used to improve the efficiency with which the iron catalyst process removes sulfide. High abatements of sulfide are reported. Another process (with a trace of iron salt) is expected to be tested in treating condensate from surface condenser units.

Spray-injecting H_2O_2 and NaOH into power plant vent gas lines (during steam stacking) may be possible since the process is successfully used in abating H_2S in steam during well drilling. Approximately 6-8 moles of H_2O_2 and 2-4 moles of NaOH are needed for each mole of H_2S.

The economics of the hydrogen peroxide process depend to a great extent on the pH of the system. At a pH of 7.0 or less, one pound of H_2O_2 reacts with 1 lb of H_2S. The cost of 100% H_2O_2 is approximately $0.50 per lb. Capital costs for this process are relatively low because they involve primarily storage tanks and pumps.

Jerry Morelli--DMJM Geothermal Systems, discussed the use of automatic controls to limit H_2S emissions by regulating steam flow and venting (also see section on Systems, Components, and Materials). Major problems with automatic controls include corroding hardware, plugging sensor lines, and H_2S-attack of electrical components. These problems can be managed with currently available technology and a rigorous schedule of routine maintenance.

Conclusions and Recommendations

1. Improve knowledge of surface condenser performance, particularly gas removal and H_2S partitioning, to increase certainty of adequate partitioning performance.
2. Encourage continued examination, testing, and evaluation of alternative means of treating H_2S in condensate, including treatment with SO_2, H_2O_2, high temperature air oxidation, catalyzed air oxidation, etc. Special consideration should be given to increased solids loading of circulating H_2O, corrosion, and waste disposal (liquid and solid).
3. Establish a test facility to develop H_2S control technology might be worthwhile.

Additional Information

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See also: Additional Information under Systems, Components, and Materials.

ACCIDENTAL SPILLS

Chairman--A.L. Franks

This work group considered the control technology applicable to accidental spills that occur while handling geothermal fluids, drilling muds, chemicals, fuels, liquid wastes, and solid wastes.

In the early stages of development at The Geysers, some wells were drilled in unstable slide areas that sometimes moved, causing spills from ruptured pipe and well casing. All new wells are now drilled in stable non-slide areas. A certified engineering geologist has to approve the site before drilling starts. Requirements for well completion and cementing are established by the California Division of Oil and Gas and reviewed by the Regional Water Quality Control Board.

Disturbance of the environment is minimized by drilling up to six wells from the same pad. It has been found that the use of one pad and one well sump for up to six wells is also very cost effective. The savings in construction costs more than compensate for the increased costs of directional drilling.

There are still 25 or 30 old wells in slide areas. These wells are under a program to prevent failures as follows:

- The area is checked for movement.
- Some slide areas are being dewatered.
- Tilt meters have been installed next to some wells.
- Wells have been reworked to strengthen systems in slide zones.
- Wells in slide areas are being replaced with new wells in stable areas.

When it is not possible to prevent failure, wells are "filled" and abandoned.

This program is considered very effective.

Before 1972, pits for storing drilling muds and fluids were not regulated and many were constructed on slides. Since 1972, each pit has been designed by a civil engineer with experience in soils. They must be lined with a layer of clay two feet thick and have a permeability of 1×10^{-6} cm/s (1 ft/yr) or less. They are designed to contain all of the flow of a 100-year storm during seasonal occurrence with an additional two foot free board. They must also be located by a certified engineering geologist in a non-slide area.

In the past, spills of drilling mud caused environmental damage from toxic chrome compounds used to control the viscosity of the mud. Drilling is now done with light muds that do not contain toxic materials such as chrome. When the drill string reaches a depth (1500-2000 ft) where temperatures are hot enough (170^{o}F) to cause lumping and caking in the mud, the use of mud is stopped and air drilling procedures are used.

After drilling is completed, pits must be closed and capped with clay within 90 days. Excess fluids are either evaporated or hauled to a class II-I disposal site as classified in Subchapter 15 of the California Administrative Code.

Procedural and construction practices since 1972 have been satisfactory with few problems. The cost has been moderate for single well pads and has resulted in substantial savings when more than one well is drilled using the same mud pit.

Spills from the steam collection and transport system have caused only a minor adverse effect on the environment. Spills can be controlled in as little as 30 minutes for a single well and 2 hours for a well field--without damage to wells. The steam producers are experimenting with automatic shut-in valves in old systems and are installing complete automation in Unit 15, which is now under construction.

In the past, failures in pipes, pumps, and operational procedures have caused problems with spills from systems handling hot water, condensate, and fluids from H_2S abatement systems. Most of the problems exist at old power plants that are not equipped with containment berms and collection sumps. All new plants are required to have berms and sumps designed with low-permeability materials meeting Regional Water Quality Control Board requirements. PG&E is going to retrofit all of the old plants with berms and sumps. PG&E is also replacing all transite pipes with high-strength fiber glass in the cooling tower systems.

The existing systems include check valves and automatic shut-in systems that are activated when a break occurs in a line between a cooling tower and a condensate pond or between a pond and an injection well. There are also high- and low-level alarms on cooling tower sumps and condensate ponds. Extra injection wells are available for back-up capacity.

All pipelines for transmitting fluids are designed to prevent rupture during any landslide that causes two adjacent supports to fail. Union Oil

Company has had landslides that destroyed four adjacent supports without failure of the condensate pipeline. Check valves and controls to prevent loss of major amounts of fluids have also been installed. Spills are limited to what drains from pipelines in the broken sections. The pipelines are also routed away from streams or other environmentally sensitive areas when possible.

There are little or no data available on transport of geothermal hot water (from liquid dominated reservoirs) in The Geysers KGRA. When the hot water resource is developed and the fluid chemistry and physical characteristics are known, the design of the system and the type of materials can be determined. More experience with these systems will be required before control methods can be developed.

The cost for controlling existing steam systems is reasonable even though condensate lines have to be replaced every few years because of corrosion. The cost of retrofitting old power plants with berm and sump systems is small compared to benefits. Controlling spills from liquid-dominated systems could be expensive.

Because of the remote location, all materials and chemicals used for drilling, constructing, and maintaining geothermal facilities must be trucked into The Geysers. Toxic wastes and excess fluids produced by geothermal operations are trucked out to authorized disposal sites. Materials trucked into The Geysers include 50% hydrogen peroxide, 50% sodium hydroxide, fuels, drilling muds and gel compounds, copper sulfate, iron sulfate, fungicides, biocides, and chlorine. Materials hauled from the site include saline drilling fluids and sludges from the hydrogen sulfide abatement systems.

Spills that occurred in the past involved both truck accidents and defective equipment. The licensing program for liquid waste haulers now in existence is not effective. There is no program for checks on certification of either operators or equipment. If a spill of toxic material occurred in a sensitive location, the cost for cleanup could be high.

Conclusions and Recommendations:

1. The existing program for locating wells in the non-slide areas and the program to replace the 25-30 wells in slide areas should both be continued.
2. We recommend that existing practices for constructing pits for drilling

muds be continued. When clays are not available, substitute liners using cement treated soils, chemical treatment, and oil base pavement have been used. Additional research on the latter three methods would be useful.

3. We recommend that all power plants be retrofitted with berm and sump systems to contain spills and that further work be done on automatic control systems for the liquid portion of existing fluid handling systems.

4. We recommend that the Liquid Waste Hauler Law be strengthened to include equipment checks, driver certification, and an appropriate schedule of fines for substandard or defective equipment.

Additional Information:

Information on drilling practices can be obtained from any of the drilling companies, the California Division of Oil and Gas, Division of Mines and Geology, the North Coast Regional Water Quality Control Board, and the Central Valley Regional Water Quality Control Board.

Information on regulating drilling mud pits and drilling mud disposal is avaliable from State Water Resource Control Board, P.O. Box 100, Sacramento, CA 95801. Data on cement treated base is available from the Concrete Institute and oil treatment from the Asphalt Institute.

Information on existing Liquid Waste Hauler licensing can be obtained from State Water Resources Control Board, P.O. Box 100, Sacramento, CA 95801.

NOISE

Chairman--Philip Leitner

This work group considered the control of noise emitted during geothermal development, including all phases from well drilling through power plant operation.

Geothermal industry operations in The Geysers-Calistoga KGRA can be a significant source of noise. As the development of geothermal energy resources has moved closer to residential areas in recent years, noise emissions from large-scale steam venting and other sources have resulted in community annoyance and complaints (Illingworth, 1976). Since ambient noise levels are generally quite low and since many local residents value a quiet environment, geothermal industry noise intrusion can become an issue with the potential to delay or prevent the addition of new electric generating capacity in certain parts of the KGRA.

Community noise is subject to local regulation in California, with counties and municipalities responsible for setting and enforcing standards. All counties are required by state law to include a Noise Element in their General Plan. This document does not set noise standards, but rather provides information about existing noise conditions, develops criteria for effective land-use planning to protect against excessive noise exposure, and establishes a policy basis for noise standards. The enactment of a noise ordinance by the County Board of Supervisors may follow adoption of the Noise Element as a part of the General Plan.

At the present time, there are no local noise regulations governing the geothermal industry in The Geysers-Calistoga KGRA. Lake County has been considering a draft noise ordinance for some time; Sonoma County has no noise ordinance. In the absence of uniform county-wide standards, geothermal noise emissions have been regulated on a project-by-project basis by county Conditional Use Permits. A project Use Permit generally specifies maximum permissible sound pressure levels as measured outside the nearest residence. These limits are usually set at 55 or 60 dBA during the day and 40 or 45 dBA at night. Whether existing noise control technology is adequate to meet these conditions for a particular project will depend on the distance between noise source and receptor and any special circumstances such as topographic barriers.

Noise Sources

A wide range of noise sources are associated with geothermal development in The Geysers-Calistoga KGRA (Table 1). The ECT Workshop discussions centered on those operations that involve the large-scale release of geothermal steam to the atmosphere, since they are most likely to be accompanied by very high noise levels and have created the greatest public concern.

TABLE 1. Noise sources associated with geothermal development activities in The Geysers-Calistoga KGRA.[a]

Development activity	Maximum sound pressure level (dBA) at 15.2 m (50 ft)
Site preparation/road construction	95
Well drilling	
Mud	85
Compressed air	
No steam	88
In steam with blooey line expander tube	122
In steam with dry cyclonic muffler	100
In steam with wet cyclonic muffler	90
Well clean-out and testing	
Venting without muffler	25
Venting with commercial muffler	110
Construction of power plant and pipelines	95
Power plant	
Normal operation	85
Steam stacking during outage condition	
Commercial vent muffler	110
Rock muffler	85
Vehicular traffic	95

[a]Data Sources: Leitner, 1978; Whitescarver, 1978; Neilson, et al., 1979.

Compressed air drilling: The last stage in drilling a geothermal well at The Geysers involves using compressed air rather than mud as a circulating medium. Large diesel-powered compressors provide the air, which returns rock cuttings to the surface and is exhausted through a pipe called the "blooey line". When a steam-bearing zone is encountered, all steam produced from the well is also released to atmosphere through the blooey line. Air drilling in steam with only a blooey line expander tube to attenuate noise can result in sound pressure levels over 120 dBA at 15.2 m (50 ft).

Well clean-out and testing: Each new well is usually vented to atmosphere at the full production rate to unload loose rock and other debris. Unmuffled venting for clean-out can be extremely noisy; sound pressure levels of 125 dBA have been measured at 15.2 m (50 ft). Production tests are then run by venting steam under different pressure and flow conditions for periods of a few hours to a few days. Commercial test mufflers of varying effectiveness are available and can attenuate emitted noise levels to 90-110 dBA at 15.2 m (50 ft).

Steam stacking at power plant: When an unscheduled power plant outage occurs, it is usually necessary to vent all or a portion of steam field production to atmosphere. If it appears that the outage will not exceed 2 days, steam will continue to be released through a muffler near the power plant. Noise levels as high as 110 dBA have been measured at 15.2 m (50 ft) from plant vent mufflers of commercial design, while rock mufflers now in use at some generating units can attenuate steam-release noise to 70-85 dBA at the same distance.

Wellhead venting during power plant startup: All wells in a steam field are completely shut in during unscheduled outages of more than 2 days, as well as during scheduled outages for maintenance and overhaul. When steam production resumes, solid debris and condensate must be unloaded from many or all of the wells. This generally requires full venting at the wellhead for periods up to several hours. No muffling devices are currently available to control this noise, which can reach 125 dBA at 15.2 m (50 ft).

Other steam-venting operations: When steam transport is initiated through a newly-constructed pipeline before the power plant starts up, pipeline vents are opened for a short time to clear debris. Rock catchers in the steam-gathering pipelines must be cleaned periodically. This operation requires unmuffled release of steam for a few minutes. Replacing wellhead master valves can result in several hours of unmuffled steam venting; fortunately, this procedure is infrequent.

Pipe and valve noise: As steam-venting noise is brought under more effective control, residual noise from turbulent flow through valves and pipes may become more important. Valves used for throttling or controlling steam flow can be responsible for loud, relatively high frequency noise.

Cooling tower noise: The mechanical draft cooling tower is usually the dominant noise source at any distance from a geothermal power plant. The large fans and falling water create a broad-band noise that does not usually cause community complaints. Sound pressure levels within 15.2 m (50 ft) of a cooling tower may be as high as 85 dBA, but fall to no more than 60 dBA at 152 m (500 ft).

Mobile and stationary engines and power equipment: Large diesel engines and other power equipment are used extensively in geothermal industry operations. Constructing access roads, well pads, and power plant sites usually requires heavy earthmoving machinery. Diesel-powered generators and pumps are used in well drilling. A variety of engines and compressors are needed in the construction of power plants, pipelines, and other facilities. Maximum noise levels are usually about 95 dBA at 15.2 (50 ft) from these types of equipment.

Noise Control Technology

In recent years the geothermal industry has made a number of improvements in operating procedures and in control equipment; these have greatly reduced noise emissions during certain activities (Whitescarver, 1978). Nevertheless, effective noise control measures have not yet been developed or implemented for some operations that involve steam venting, including large-scale wellhead releases. The current status of noise reduction techniques was discussed in detail at the ECT Workshop and is summarized below.

Compressed air drilling: The simple blooey line expander tube is no longer used during air drilling. The blooey line discharge of compressed air, rock cuttings, and geothermal steam is now directed into a large cyclonic separator/muffler. When water is injected into the expander tube just before the flow reaches the separator/muffler, noise levels are reduced substantially. Sound pressure levels at 15.2 m (50 ft) from these devices do not exceed 90 dBA, even with steam flow rates of 45,000 to 90,000 kg/hr (100,000-200,000 lb/hr). Although cyclonic separator/mufflers are large and expensive ($25,000-50,000), they are now used routinely by all drilling operators at The Geysers because of their proven reliability and effectiveness in reducing noise.

Well clean-out and testing: Initial well clean-out can usually be accomplished through the cyclonic separator/muffler while the drill rig is still in place. While this provides effective noise attenuation, there may be some additional erosion of the separator/muffler from rocks and smaller particulates entrained in the steam. Wells may be cleaned out after the separator/muffler is removed from the site. Although the operation may last only a few hours, the unmuffled noise can result in complaints from residents more than a mile distant.

The portable commercial mufflers used in production tests are marginally effective; an increased attenuation of 10 dBA or more would be useful in some situations. However, the impacts can be minimized by restricting operations to daylight hours and by directing steam flow into the pipelines when these are available. Since production tests are usually conducted only once for a relatively brief period at each well, improved noise control technology was not seen as a critical need.

Steam stacking at power plant: Large metal mufflers for plant vents, commercially designed and manufactured, have been used regularly for many years at the generating units of The Geysers Power Plant. Mufflers of this kind have not reduced noise as much as is desirable for some sensitive locations. However, where the generating units are remote from residential areas they are probably adequate. They are not durable under service conditions at The Geysers, where they have suffered from corrosion, scaling and plugging, vibration, and erosion due to particulates.

Recently Union Oil Company has successfully adapted a rock muffler design to handle the large steam flows that must be vented to atmosphere during a power plant outage. These mufflers are simply large concrete pits filled with lava rock. Steam is released through a diffuser system at the bottom of the pit. Their effectiveness in noise attenuation is outstanding and maintenance requirements have been minimal. Many of the existing generating units at The Geysers have been retrofitted with rock mufflers. The major disadvantage is the cost--approximately $150,000-200,000 for a rock muffler sized for steam flow rates of 450,000 kg/hr (1,000,000 lb/hr) or more. This is considerably more expensive than the commercial plant vent mufflers that have been used in this application.

<u>Wellhead venting during power plant startup</u>: The ECT workshop participants considered that developing an effective and practical method for reducing steam-vent noise at the wellhead is the noise control issue of highest priority for several reasons:

- Wellhead venting generates by far the most noise of any regularly occurring geothermal industry operation,
- it may lead to unacceptable effects on adjacent communities, and
- no adequate control technology is currently available.

The use of standard commercial blow-off silencers is considered impractical because of severe operating conditions. These devices cannot withstand the rocks, smaller particulates, and slugs of water that can be discharged in the geothermal steam during well clean-out. Furthermore, contaminants in the steam can cause accelerated metal corrosion on the one hand and scaling and plugging on the other.

If steam field production could be vented through a rock muffler at the power plant during outages, wells would not have to be shut-in and the extremely high noise levels accompanying well clean-out and generating unit startup could be avoided. However, this procedure would conflict with H_2S abatement goals because the large quantities of steam vented through the rock muffler cannot presently be treated to remove the H_2S. Union Oil Company and other steam suppliers recently initiated a program that avoids well shut-in during short-term unscheduled outages while it minimizes steam stacking and associated H_2S release. Vee-ball throttling valves are being installed on wells with production rates of 27,000 kg/hr (60,000 lb/hr) or more. Within 4 hours after an outage, steam field production can be cut approximately in half; if the outage is expected to last more than one day, steam can be shifted over intertie pipelines to adjacent generating units. Thus, in many outages it is no longer necessary to completely shut-in steam wells, and wellhead venting during power plant startup can be eliminated.

Unfortunately, this solution is not available at isolated power plants that cannot be linked to other units by intertie pipelines. At these facilities, steam field production can be throttled back to 40-50% of normal rates and the remainder stacked at the plant for 1 or 2 days at most before well shut-in is required. In addition, of course, this procedure is not useful in long-term scheduled or unscheduled outages at any geothermal power plant; in these cases the steam field must still be shut-in.

Two basic approaches to the noise problem associated with wellhead venting were discussed at length during the ECT Workshop:

1. Adapting technology used to suppress supersonic jet aircraft noise to produce a flow-through steam vent nozzle/diffuser, and

2. Adapting the rock muffler design for the plant vent to the special requirements of well clean-out venting.

The noise created by supersonic jet engine exhaust is quite similar to that from venting geothermal steam. In both cases, a very loud broad-band noise is generated mainly by turbulent mixing between the ambient air and a supersonic jet of hot gas that exits through a restricted nozzle. The basic goal in jet noise suppression is to bring the velocity of the supersonic flow down into the sonic region in the shortest possible distance from the nozzle exit.

A great deal of research has been carried out by the U.S. government and by the aircraft industry on the physics of jet noise and on various methods of jet noise suppression. Professor Henry T. Nagamatsu (Rensselaer Polytechnic Institute) presented the results of his extensive studies on jet noise phenomena and noise suppression concepts to the ECT Workshop. Many suppressor configurations have been tested and some may apply to control of geothermal steam venting noise. Jet exhaust velocities can be reduced by shock waves created by small rods inserted in the flow field, by a secondary jet injection perpendicular to the primary jet, by inducing ambient air flow around the jet with single or double shrouds, and by dividing jet flow through multiple exits. The noise level has been reduced 5-20 dB with these techniques. However, some of the most effective suppressor designs may not be easy to adapt to geothermal well venting because they require placing multiple tubes and shrouds in the path of the steam discharge. A device of this type could be damaged from rocks and smaller particulates during well clean-out.

In any event, it will not be possible to immediately build and test full-scale jet noise suppressors for the geothermal industry. Since little is known about the physics of steam jet mixing with ambient air, a program of basic measurements will be required to define the range of operating conditions encountered in steam venting. These data will allow selecting a few alternate suppressor configurations for model study under scaled flow conditions. Only then will it be possible to proceed to fabricate, install, and field test full-scale noise suppressors for well clean-out. Because of the research and development effort needed, it is not possible at this time to forecast the effectiveness or cost of any such devices.

Small rock mufflers show promise for the control of steam-venting noise at the wellhead. The larger plant vent rock mufflers are known to be extremely effective in noise reduction; it is reasonable to project that a properly sized wellhead rock muffler could achieve an attenuation of at least 30-40 dBA (i.e., from an unmuffled level of 125 dBA to 85-95 dBA). The main question at present concerns the durability of the piping that would carry the well discharge to the rock muffler during clean-out. Rocks and smaller particulates may cause some accelerated erosion, especially at 90^{o} elbows, but use of tee fittings and heavy reinforced sections where needed, along with periodic repair and replacement, should prevent any real difficulties.

The initial installation cost of a wellhead rock muffler is estimated at about $20,000; however, there should be little maintenance expense. Although the capital outlay is considerable, the current practice of field development through directional drilling should make the per well cost of this control technology more reasonable. If 4 to 6 wells are drilled from the same pad, a single rock muffler can serve all of them. Furthermore, rock mufflers will only be needed at those wellsites that are close to sensitive noise receptors. At least one steam supplier is presently constructing rock mufflers for use during startup of certain existing wells close to a residential area. They should be operational early in 1980 and it will be possible at that time to evaluate their performance.

<u>Other steam-venting operations</u>: Special noise control techniques are probably not needed for the venting that occurs during the commissioning of the steam gathering system. This initial clean-out of the pipelines will only take place once in each steam supply field and will only last a few hours. Similar considerations would apply in the case of venting during the replacement of a wellhead master valve. This operation is required about every 3 to 5 years and involves only a brief period of unmuffled venting. Finally, new rock catchers are available that do not become plugged so that venting during clean-out can be eliminated.

<u>Pipe and valve noise</u>: The theoretical and practical aspects of pipe

and valve noise problems are well-understood. A variety of quiet valves are available for many applications. Noise reduction devices can be installed to deal effectively with valve noise in existing steam gathering systems where needed. Commercial vendors can provide the necessary expertise and equipment (either off-the-shelf or custom-designed) to solve noise problems in this area at moderate cost.

Cooling tower noise: The most practical and cost-effective approach to cooling tower noise problems is to site the facility at an appropriate distance from residential areas. It may also be possible to take advantage of topographic barriers to further attenuate noise. When a power plant with its associated cooling tower must be located near sensitive receptors, several kinds of noise reduction technology are available. For example, low noise level fans may be specified. It is also possible to specify fans that operate at a lower speed at night when less cooling is necessary. Cooling tower manufacturers can provide details on the effectiveness and expense of these noise reduction features. In general, costs are quite high because of the large size of these facilities.

Mobile and stationary engines and power equipment: Methods are readily available for controlling noise from the power equipment used in site preparation, well drilling, and power plant and pipeline construction. Properly placing stationary equipment on the work site can reduce the exposure of receptors. Correct operational procedures can minimize noise emissions and can especially help in avoiding sudden changes in noise intensity and frequency. Noise control technology, including effective mufflers, acoustic barriers, and enclosures, can be used when the cost is justified by the need to protect nearby receptors.

Conclusions and Recommendations

Although considerable progress has been made in reducing geothermal industry noise at The Geysers, there are still occasional episodes of very high noise emissions. The major remaining problem is unmuffled venting of large amounts of steam at each wellhead during power plant startup. While no general noise standards exist now, it is likely that new geothermal development projects will prove unacceptable if they entail unmuffled wellhead venting within two miles of residential areas.

Thus, there is a clear need for noise control technology that can significantly reduce wellhead venting noise. The most promising approach seems to be adapting the rock muffler design that has been used successfully in steam venting at the power plant. It may also be possible to develop a steam vent nozzle/diffuser for wellhead venting based on the technology used in control of noise from supersonic jet engine exhaust. Existing noise controls appear to be adequate in most situations to keep noise from other geothermal industry sources within acceptable limits. Additional improvements can continue to be made by using standard techniques and equipment where necessary.

It is important to emphasize that the jet noise created by steam-venting operations at The Geysers is a site-specific problem. Many parts of The Geysers field are so remote from residential areas that no special noise control measures are required. Furthermore, steam-venting noise should not present difficulties at most liquid-dominated geothermal resource areas, so that noise control systems developed for The Geysers vapor-dominated reservoir will not be widely used elsewhere.

Several recommendations are indicated by the findings of the ECT Workshop:

1. The development of a rock muffler capable of reducing steam venting noise at the wellhead to 95 dBA or less should be vigorously pursued. Because of the cost of these installations, it will be important to arrive at accurate methodology for determining the correct size and configuration in particular applications. In addition, the practical performance of different types, sizes, and shapes of rock or aggregate should be evaluated.

2. Various concepts derived from jet noise suppressors developed for aircraft engines may have merit for controlling geothermal steam venting noise. An extensive R&D effort will be needed to identify and test the most promising alternate designs. It will be very important to aim at designs that can combine effective noise suppression with moderate cost and reasonable size and weight.

3. Any federal program to develop noise control technology applicable to The Geysers should involve the close cooperation and assistance of the private sector, including steam suppliers and utilities.

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SYSTEMS, COMPONENTS AND MATERIALS

Chairman--James T. Kuwada

This work group examined the systems, components, and materials used in the design of the steam-gathering system and power plants. We assessed the conditions under which noise and discharges of H_2S-bearing steam and condensate would impair the environment. The aims were threefold:

- Determine the location, frequency, and magnitude of the impact to gage the severity of the problems,
- ascertain what could be done with existing technology to mitigate these problems, and
- establish appropriate and needed areas for research and development.

While there are a number of bleeds and vents from the piping system and separator in the steam-gathering system, H_2S discharges from these sources are relatively minor. There are two circumstances under which a lot of noise is generated and significant amounts of H_2S are discharged: during well startup when flow is initiated to heat up and dry out the well, and when a load change at the power plant requires steam-venting at the vent station to maintain pressure control on the steam supply system. In each case, hydrogen sulfide gas is discharged to the atmosphere with the steam. The period of well heatup and dryout is short, so the amount of H_2S discharged at this time is within acceptable limits, but the high velocity of the steam generates an unacceptably loud noise.

A variety of muffler designs have been installed on the discharge pipe with varying degrees of success in attenuating the noise. However, these mufflers have not been satisfactory over the long term because particulates entrained in the steam erode internal parts. Satisfactory results have been achieved with rock mufflers; a rock muffler is made of a diffuser pipe housed in a concrete enclosure containing a 6- to 8-foot bed of lava rock through which the vented steam is dissipated. The superficial velocity through the rock bed is about 1,200 lb/hr per ft^2; several mufflers, each about 20- by 30- by 15-ft, are required to accomodate the total vented steam.

While the rock mufflers answer the immediate needs, they are large, cumbersome, and relatively expensive to install. Improved designs that are compact, shop-fabricated, and easy to install are desirable. Research and development are needed in this area. Steam suppliers have come to accept that they should minimize the amount and duration of steam venting when the power plant load is reduced. Regulations requiring that the wells be shut in within 2 hours for a scheduled plant outage--and within 4 hours for an unscheduled plant outage lasting more than 24 hours--have been imposed. To comply with these new requirements, the steam suppliers for Units 13 and 15, which are currently under construction, are installing automatic throttling valves at the wellhead. These will be centrally controlled to respond to load changes in the power plant and will eliminate venting of excess steam. A description of the control system for the steam supply network for Unit 15 is attached for reference (see Additional Information).

The automatic steam-throttling valve is located close to the wellhead to minimize the length of steam piping that must withstand the well shutoff pressure of 500 psig. A 10-in. ball valve was tested in the field and provided good steam throttling, but the particular valve's bearing was damaged at a differential pressure of 350 psi. This ball valve was field-modified for this application. The manufacturer is confident that valves can be furnished to operate satisfactorily because ball valves are commonly subjected to more severe service conditions in industry.

Electronic controls are now commonly used on increasingly complex and sophisticated control systems. Presently available technology can provide the required automation without special research and development devoted to hardware. Reliably operating the instrumentation and controls, however, requires understanding of the special conditions imposed by contaminants in geothermal steam and condensate. For instance, the effect of long-term hydrogen sulfide attack on electronic equipment is disastrous.

When the electronics are housed in NEMA 4 cabinetry, they are successfully isolated from weather and noxious vapors. By circulating the air within the cabinet, and by providing proper internal absorptive filters to clean up air introduced by opening the cabinet door for service or inspection, one can assure that even the most sensitive of electronic devices can operate in the field indefinitely and dependably.

Particulates in the steam can deaden a transmitter if they choke off an impulse line with deposits or silt. Prudent installation practices can minimize this problem. Also, adequately sizing separators to accommodate flow surges can virtually eliminate silting and clogging of the separator--and consequent blow-through of particulate matter into the turbine.

Although instruments and hardware are available, the ultimate success of the control system for the steam gathering network will be determined by the degree to which we understand and design the control system to respond to the well and piping system flow dynamics. Setting the controls properly to balance each circuit in the piping network--so as to prevent steam venting on the one hand and inadvertent tripping of the turbine on the other, is a complex problem, whose solution will have to be established by trial and error. The problems stem from the size of the system: the steam gathering system connects as many as 19 wells, each well has a different flow rate, and the length of pipe from wellhead to plant amounts to some 28,5000 total feet of capacitance.

Research is needed to develop a predictive dynamic computer model to aid in designing automatic control systems for steam gathering pipeline networks that handle large volumes. Computer modeling an expandable mathematical representation of such a system would allow suppliers to determine in advance the heat transfer losses, optimize heat insulation, minimize system warmup and startup times, and maintain constant stable pressures at the point where steam transfers to the power plant. Controller design and settings predicted by such a model would assist the suppliers in minimizing an otherwise prolonged design and operational startup time.

Conclusions and Recommendations:

1. Mufflers with improved designs are needed for use during steam venting. They should be compact, shop-fabricated, easy to install units. Research and development are needed in this area.

2. Research is needed to develop a predictive dynamic computer model to aid in designinig automatic control systems for large volume steam-gathering networks.

3. Environmental regulations for the geothermal industry present moving targets to the steam suppliers and the utility. The technology in instruments and control systems has been advancing at a rate that has allowed the engineer to meet the changing regulations. This is being done through the use of computers, data transmission equipment, and other standard controls. The key is not the capability but rather the cost of meeting the regulations.

4. Within the scope of subjects discussed, it was the general conclusion of the group that technologies to solve most problems associated with systems, components, and materials at the Geyers already exist between the steam supplier and the utility. However, both time and money are needed to find solutions.

Additional Information

A CONTROL SYSTEM FOR STEAM GATHERING AT THE GEYSERS

William L. O'Daly

Thermogenics, Inc.
A Subsidiary of
Hughes Aircraft Company
Culver City, California 90230

Gennaro Morelli

Daniel, Mann, Johnson, & Mendenhall
3250 Wilshire Boulevard
Los Angeles, California 90010

Steam gathering and delivery to the new Pacific Gas & Electric Company (PG&E) Unit 15 at The Geysers will be controlled by an automatic computerized system.

Thermogenics, Inc., lease owner and operator, and the consulting firm of Daniel, Mann, Johnson, & Mendenhall (DMJM) initiated the development of a controlled steam-venting system in response to Northern Sonoma County Air Pollution Control District (APCD) requirements for reducing total H_2S emissions. The APCD's approval of a construction permit was contingent on installing a gathering system that could rapidly reduce emergency steam venting during air quality episode alerts.

Total reservoir steam venting usually occurs because of unscheduled power plant outages. At existing plants, this venting continues unabated until the gathering system can be turned down. The steam wells are manually shut in if the power plant is to remain out of service for an extended time. Manual shutdown of existing steam fields can take several hours.

The Northern Sonoma County APCD requirement for the Thermogenics steam field specifies capability to reduce unabated steam venting by 60 percent within one hour. As of this writing, the California Air Resources Board is close to approving rules that would require reducing H_2S emissions resulting from "stacking" (venting) 90 percent within 15 minutes. Commitment of funds by Thermogenics, Inc., to design and construct a gathering system that would comply with the APCD venting requirements afforded a basis for justifying additional funds for a completely automatic system.

Automatic control systems added about 15 % to the investment cost of the gathering system. Approximately 50% of that increase was required simply to

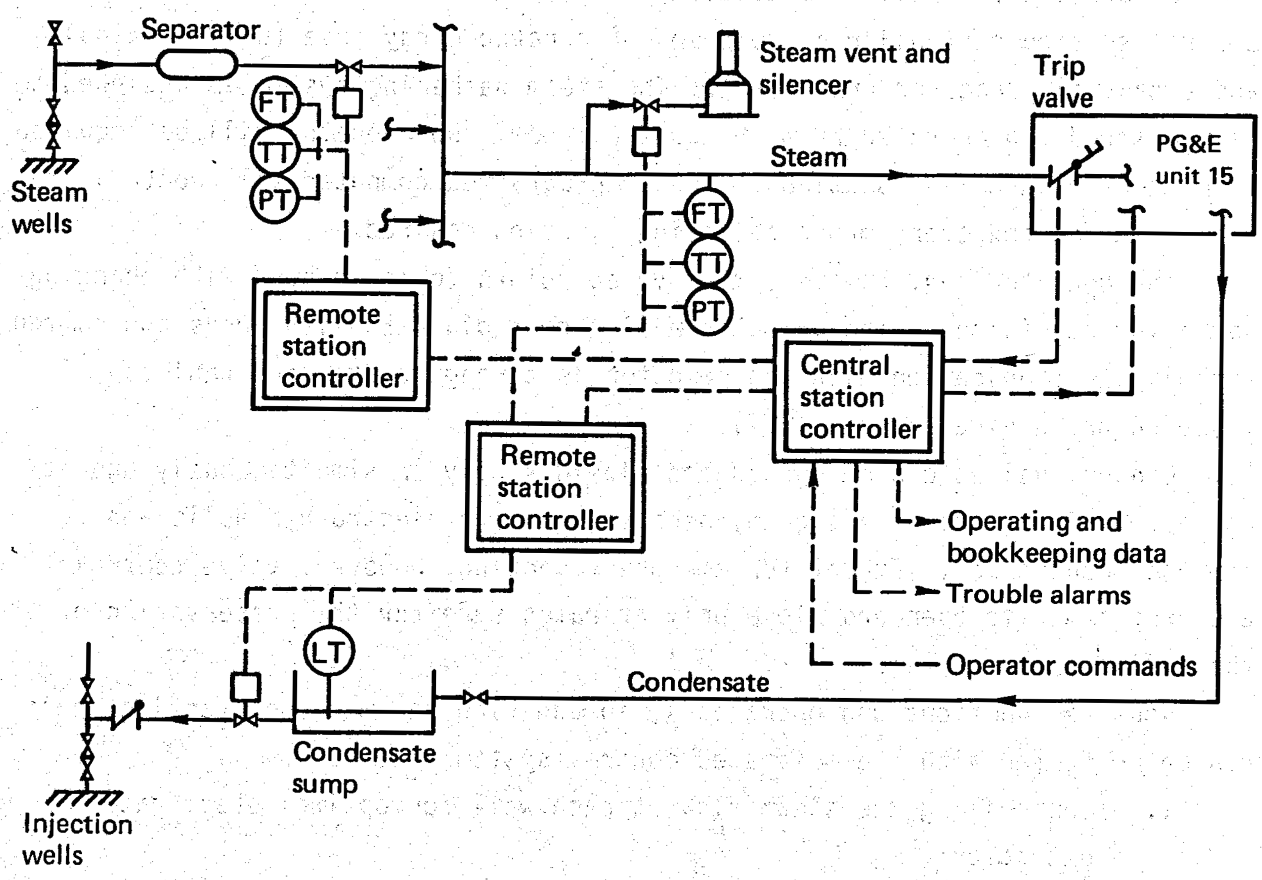

Fig. 1. Flow diagram of a control system for steam gathering at The Geysers.

control emissions. The addition of controllers and computers has converted a remote, manually operated system into an automatic system and established a control center for operating future steam reservoirs. The savings to be realized in operating manpower alone has been determined to be cost-effective.

The simplified flow diagram presented above (Fig. 1) shows the major components of the Thermogenics steam gathering system. There are nine steam wells connected by pipeline with PG&E Unit 15. A condensate line from Unit 15 returns water to a collection sump. The sump delivers the condensate to injection wells by pipeline. Powered control valves are located at each well, at the condensate sump exit, and at the steam manifold venting system.

Remote station controllers are installed near the control valves, and a central station controller is located in an operator's control room. The central station controller is composed of a cathode ray tube (CRT) terminal and a central processor unit (CPU). The steam gathering system is designed to be monitored and operated from the control room. No operator will be required to perform programmed functions. The preprogrammed computer will control the steam venting and every other operating function desired.

The operator can, however, modify set points to correspond with changing operating conditions. The computer will accept plain English words and common symbols. Communication with the computer is through a standard tabletop keyboard and a video screen (CRT).

Control valves can be opened and closed singly or simultaneously and at any speed (fractions of a second) because they are electro-hydraulic and computer-controlled. Except for emergency venting, however, valve controls are programmed to open and close only at rates safe for the preservation of the wells.

Routine functions and operations, in addition to emergency venting, that can be performed with the automated control system are:

1. Controlling the steam flow at each well for optimal steam rate extration;
2. Automatic balancing of the system for delivering steam at the flow, pressure, and temperature required by the turbine;
3. Accelerated plant startups and shutdowns;
4. Continuous data collection on well production and status;
5. Centralized operation and control of both the newly installed a future Thermogenics steam gathering systems;

6. Periodic data printout as programmed or on operator command;
7. Data acquisition during well testing.

The above capabilities result in the following advantages:

1. Reduced $H_2$2 emissions,
2. Fewer operators,
3. Steam conservation resulting from faster and more accurate operations,
4. Fast response to the steam turbine needs,
5. Well status records showing trends in anticipation of the need for new wells,
6. Central control of several steam fields,
7. Reduced maintenance costs because of fewer discrete instruments.

Government requirements for abating H_2S emissions at The Geysers will require relatively large investments for equipment. More efficient use of this equipment can be realized by adapting it for automatically controlling operations. This bold approach taken by Thermogenics, Inc., in accepting the challenge of H_2S emissions abatement sets a new trend in operating steam gathering systems.

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The generous donation of time and expertise by participating organizations and their employees is gratefully acknowledged. In particular, we thank the members of the steering committe (Appendix A) and the individuals who chaired individual sessions of the workshop: Gordon W. Allen, Pacific Gas and Electric Co.; Louise E. Capuano, Thermogenics, Inc.; A.L. Franks, California Water Resources Control Board; James T. Kuwada, Rogers Engineering Co., Inc.; Phillip Leitner, St. Mary's College; and Neil A. Moyer, California Air Resources Board. We also wish to express our appreciation to the staff of The Geothermal Resources Council for their excellent job of providing liaison and logistic support for the meeting, and particularly to Dave Anderson who chaired the general sessions and provided many valuable suggestions for conducting the workshops. In addition, we thank John Porter and his staff (LLL) who helped arrange and conduct the workshop.

APPENDIX A. Membership list for the steering committee, The Geysers-Calistoga environmental control technology workshop.[a]

George A. Frye
Geothermal Resources Division
Aminoil USA, Inc.
1250 Coddingtown Center
Santa Rosa, CA 95401

Dr. Alexander N. Graf
Lawrence Berkeley Laboratory
Earth Sciences Division
Bldg. 90, Room 1012E
1-Cyclotron Road
Berkeley, CA 94720

David M. Hill
California Energy Resources and Development Commission
1111 Howe Avenue
Sacramento, CA 95825

Hutch Hutchinson
The Ben Holt Co.
201 South Lake Avenue
Pasadena, CA 91101

Dr. Philip Leitner
St. Mary's College
Moraga, CA 94575

H. Jack Miller
Division of Oil and Gas
Department of Conservation
240-D Coddingtown Center
Santa Rosa, CA 95401

Warren A. Smith
Union Geothermal Division
Union Oil Co. of California
P.O. Box 6854
Santa Rosa, CA 95406

David Snetsinger
Water Quality Control Board
North Coast, Region 1
1000 Coddingtown Center
Santa Rosa, CA 95401

Michael W. Tolmasoff
Northern Sonoma County Air Pollution Control District
141 North Street
Healdsburg, CA 95448

Carl J. Weinberg
Pacific Gas and Electric Co.
3400 Crow Canyon Road
San Ramon, CA 94583

[a]Topics included in the workshop were suggested by the steering committee which met at the San Francisco Airport Hilton, San Francisco, California, on July 12, 1978. A list of workshop participants was also suggested by the steering committee.

Appendix B. List of attendees at The Geysers-Calistoga environmental control technology workshop.

Lila ABRAHAMSON
Lawrence Livermore Laboratory
Technical Information Dept., L-452
Livermore, CA 94550
(415) 422-5680

Gordon W. ALLEN
Pacific Gas & Electric Co.
9900 Crow Canyon Road
San Ramon, CA 94583
(415) 820-2000, x-273

David N. ANDERSON
Geothermal Resources Council
P.O. Box 98
Davis, CA 95616
(916) 758-2360

Jeffrey ANDERSON
California Energy Commission
Engineering & Environmental Div.
1111 Howe Ave.
Sacramento, CA 95825
(916) 322-3677

Meredith Joan ANGWIN
Acurex Corporation
485 Clyde Avenue
Mountain View, CA 94306
(415) 964-3200, x-3463

Clifton L. BLACK
Ralph M. Parsons Company
100 W. Walnut St.
Pasadena, CA 91124
(213) 440-3837

Peter BRENNAN
Boeing Technology Services
P.O. Box 3707, MS 40-67
Seattle, WA 98124
(206) 655-2168

F.C. BROWN
EIC Corporation
55 Chapel St.
Newton, MA 02158
(617) 965-2710

Scott BROWN
NOVA Systems
39 Washington Ave.
Point Richmond, CA 94801
(415) 233-9833

Robert F. BUHL
Union Oil Co. of California
Research Department
P.O. Box 76
Brea, CA 92621
(714) 528-7201

Mike BURTON
Fisher Controls
P.O. Box 190
Marshalltown, IA 50158
(515) 754-3149

Ronald C. BUSH
Pacific Gas & Electric Co.
Dept. of Engineering Research
3400 Crow Canyon Road
San Ramon, CA 94583
(415) 820-2000, x-296

Daniel B. CALLAWAY
Industrial Accoustics Co., Inc.
1009 Wilshire Blvd.
Santa Monica, CA 90401
(213) 393-0265

Louis E. CAPUANO, Jr.
Thermogenics, Inc.
2300 County Center Dr., Suite 250
Santa Rosa, CA 95401
(707) 546-7301

Harry M. CASTRANTAS
FMC Corporation
Industrial Chemical Div. R&D
P.O. Box 8
Princeton, NJ 085450
(609) 452-2300

Dean CORNETT
Lawrence Livermore Laboratory
Environmental Sciences Div.
P.O. Box 5507, L-453
Livermore, CA 94550
(415) 422-3880

Glenn COURY
Coury & Associates, Inc.
7400 West 14th Ave., Suite 2
Lakewood, CO 80215
(303) 232-3823

Thomas P. CUTINO
Graham Manufacturing Co.., Inc.
953 San Pablo Ave.
P.O. Box 146
Pinole, CA 94564
(415) 223-5554

Stephen A. DAVIES
Thermogenics, Inc.
2300 County Center Dr.,
Suite 250
Santa Rosa, CA 95401
(707) 546-7301

Leo DEFFERDING
Battelle Northwest Laboratories
P.O. Box 999
Richland, WA 99352
(509) 946-2792

Donald L. ERMAK
Lawrence Livermore Laboratory
P.O. Box 808
Livermore, CA 94550
(415) 422-3880

Dave FACH
U.S. Geological Survey
Area Geothermal Supervisor's Ofc.
345 Middlefield Road
Menlo Park, CA 94025
(415) 323-8111, x-2848

Dan FONG
California Energy Commission
Engineering & Safety Office
1111 Howe Ave.
Sacramento, CA 95825
(916) 322-5135

A.L. FRANKS
Calif. Water Res. Control Board
2014 T Street
P.O. Box 100
Sacramento, CA 95801
(916) 445-2774

Donald B. GILMORE
U.S. Env. Protection Agency
Env. Monitoring & Support Lab
P.O. Box 1507
Las Vegas, NV 89114
(702) 736-2969

R.W. GOULD
EG&G Idaho, Inc.
P.O. Box 1625
1975 Everest
Idaho Falls, ID 83401
(208) 526-0265

Gil GRAY
Associated Process Controls
(Fisher Controls)
330 Hatch Drive
Foster City, CA 94404
(415) 574-1300

Paul H. GUDIKSEN
Lawrence Livermore Laboratory
P.O. Box 808, L-262
Livermore, CA 94550
(415) 422-1813

Joseph A. HALTERMAN
California Energy Commission
1111 Howe Ave.
Sacramento, CA 95825
(916) 322-3811

Robert P. HARTLEY
U.S. Env. Protection Agency
Industrial Env. Rsearch Lab
5555 Ridge Ave.
Cincinnati, OH 45268
(513) 684-4335

Joseph J. HENAO
Calif. Water Res. Control Board
P.O. Box 161044
Sacramento, CA 95816
(916) 322-1589

Harvey HENNIG
Union Oil Co. of California
Reserch Center
P.O. Box 76
Brea, CA 92621
(714) 528-7201

John HILL
Lawrence Livewrmore Laboratory
P.O. Box 808
Livermore, CA 94550
(415) 422-3880

Larry JOYCE
California Energy Commission
Assessment Division
Supply Assessment Office
1111 Howe Ave., MS 39
Sacramento, CA 95825
(916) 920-6405

Gerald KATZ
U.S. Department of Energy
Geothermal Energy Division
1333 Broadway
Oakland, CA 94612
(415) 273-7943

Richard KISHI
California Energy Commission
Engineering & Environmental Div.
1111 Howe Ave.
Sacramento, CA 95825
(916) 322-5135

Lawrence E. KUKACKA
Brookhaven National Laboratory
Department of Energy & Environment
Building 26
Upton, NY 11973
(516) 345-3065

Jim KUWADA
Rogers Engineering Co., Inc.
111 Pine Street, Suite 600San Francisco, CA 94111
(415) 986-6546

John LASZLO
Pacific Gas & Electric Co.
77 Beale Street, Room 2513
San Francisco, CA 94106
(415) 781-4211, x-1733

David W. LAYTON
Lawrence Livermore Laboratory
P.O. Box 5507, L-453
Livermore, CA 94550
(415) 422-3840

Phillip LEITNER
St. Mary's College
Biology Department
Moraga, CA 94575
(415) 376-4411, x-365

Jerry LEWIS
Fluor Engineers & Constructors
3333 Michelson Dr., C2-F6-6
Irvine, CA 92730
(714) 975-3567

Charles T. LI
Battelle Northwest Laboratories
P.O. Box 999
Richland, CA 99352
(509) 946-2760

Ray S. LONG
Dow Chemical Company
2800 Mitchell Drive
Walnut Creek, CA 94598
(415) 944-2095

Lyman E. LORENSEN
Lawrence Livermore Laboratory
P.O. Box 808, L-338
Livermore, CA 94550
(415) 422-7035

Donald P. MALONEY
Elliott Company
P.O. Box 6990rinda, CA 94563
(415) 254-5041

Dowell E. MARTZ
Napa County Board of Supervisors
P.O. Box 96
Angwin, CA 94508
(707) 965-2777

Dudley McFADDEN
Honeywell, Inc.
2025 Gateway Place, Suite 380
San Jose, CA 95110
(408) 998-03131

Lowell A. MILLER
U.S. Department of Energy
San Francisco Operations Office
1333 Broadway
Oakland, CA 94612
(415) 234-7963

Terrence V. MOLLOY
Pacific Gas & Electric Co.
77 Beale St., Room, 2586
San Francisco, CA 94619
(415) 781-4211, x1801

Marla MOODY
Lawrence Livermore Laboratory
P.O. Box 808, L-453
Livermore, Ca 94550
(415) 422-3880

G. MORELLI
DMJM
3250 Wilshire Blvd.
Los Angeles, CA 90010
(213) 381-3663

Neil A. MOYER
California Air Resources Board
1102 Q Street
P.O. Box 2815
Sacramento, CA 95812
(213) 575-6844

Henry NAGAMATSU
Rensselaer Polytechnic Inst.
1046 Cornelius Ave.
Schenectady, NY 12309
(518) 270-6260

Thomas R. NORRIS
Consultants in Engineering Acoustics
350 Pacific Ave.
San Francisco, CA 94111
(415) 397-0442

Dennis OLMSTEAD
California Divison of Oil & Gas
1416 Ninth Street
Sacramento, CA 95814
(916) 445-9686

Thomas E. PERRY
San Diego Gas & Electric Co.
P.O. Box 1831
San Diego, CA 92112
(714) 232-4252, x-2173

John A. PETERSON
ARMCO, Inc.
Research & Technology
Middletown, OH 45043
(513) 425-2593

Paul L. PHELPS, Jr.
Lawrence Livermore Laboratory
P.O. Box 5507, L-453
Livermore, CA 94550
(415) 422-3880

Richard RATHVON
California Energy Commission
1111 Howe Ave., MS 2
Sacramento, CA 95825
(916) 920-6811

Suzanne REED, Commissioner
California Energy Commission
1111 Howe Ave.
Sacramento, CA 95825
(916) 920-6811

John F. RICHARDS
Fluid Kinetics Corporation
1343 Callens Road
Ventura, CA 93003
(805) 644-5587

Daryl ROLL
Halliburton Services
P.O. Box 2947
Santa Fe Springs, CA 90670
(213) 863-8701

Michael K. SAIKI
U.S. Fish & Wildlife Service
CNFRL, Field Rsearch Unit
P.O. Box C
Davis, CA 95616
(916) 756-1946

R.J. SALAZAR
U.S. Department of Energy
San Francisco Operations Office
1333 Broadway
Oakland, CA 94612
(415) 273-7963

Alvin SAMUELS
Ironite Products Co.
822 Perdido
New Orleans, LA 70112
(502) 581-5163

Konrad T. SEMRAU
SRI International
333 Ravenswood Ave.
Menlo Park, CA 94025
(415) 326-6200

S. Garrett SHARP
Pacific Gas & Electric Co.
3400 Crow Canyon Road
San Ramon, CA 94583
(415) 820-2000

Warren A. SMITH
Union Oil Co. of California
P.O. Box 6854
Santa Rosa, CA 95406
(707) 542-9543

David F. SNOEBERGER
9740 Mercerwood Drive
Mercer Island, WA 98040
(206) 236-0914

Elgar STEPHENS
Calif. Division of Mines & Geology
2815 O Street
Sacramemto, CA 95816
(916) 322-9995

Nancy H. STOLESEN
McCulloch Geothermal
3570 Lakeshore Blvd.
Lakeport, CA 95453
(707) 263-4997

Thomas TANTOM
California Energy Commission
Engineering & Safety Office
1111 Howe Ave.
Sacramento, CA 95825
(916) 322-3677

Mike TOLMASOFF
Northern Sonoma County APCD
141 North Street
Healdsburg, CA 95448
(707) 433-5911

Fayne L. TUCKER
Lake County Air Pollution Control Dist.
255 N. Forbes St.
Lakeport, CA 95453
(707) 263-2391

Carl WEINBERG
Pacific Gas & Electric Co.
3400 Crow Canyon Road
San Ramon, CA 94583
(415) 820-2000

Oleh WERES
Lawrence Berkeley Laboratory
Building 90, Room 1140E
One Cyclotron Road
Berkeley, CA 94720
(415) 843-2740, x-5625

Dr. Eric WOOD
Bolt Beranek & Newman Inc.
50 Moulton Street
Cambridge, MA 02138
(617) 491-1850, x-704

C.E. WOODS
Aminoil USA, Inc.
P.O. Box 11279
Santa Rosa, CA 95401
(707) 527-5332

Steve ZALUSKY
Lake County Air Pollution Control Dist.
255 N. Forbes Street
Lakeport, CA 95453
(707) 263-2391

Appendix C. Work groups, workshop on environmental control technology for The Geysers-Calistoga KGRA

Following is a list of the six workshop work groups, each with a breakdown of some important sub-items as identified by the steering committee. This list of topics is not all-inclusive and is intended to guide the discussions but not to limit them. Note that these work group topics and sub-topics should be considered, when possible, by each work group in the light of both electric and non-electric development of the resource.

WORK GROUP NO. 1

Hydrogen Sulfide - Upstream of Turbine

Control Techniques

1. Chemical
2. Mechanical
    - Throttling Valves
    - Systems Design
        - Materials
        - Automatic Controls

Control Areas

1. Wells (drilling and clean-out)
2. Pipeline steam vents
3. In line steam (ahead of turbine)

WORK GROUP NO. 2

Hydrogen Sulfide - Downstream of Turbine

Control Techniques

1. Chemical
2. Mechanical
   - Throttling Valves
   - Systems Design
     - Materials
     - Automatic Controls
     - Condensers

Control Areas

1. Steam condensate (condenser and hot well)
2. Non-condensable gasses

WORK GROUP NO. 3

Noise

Drilling

1. Pipe Ring
2. Diesel Engines
3. Air Drilling Mufflers

Testing

1. Well Clean-out (portable mufflers)
2. Well Tests (portable mufflers)

Power Plants

1. Cooling Towers
2. Stacks
3. Bleeders

WORK GROUP NO. 4

Accidental Spills

1. Condensate Systems
2. Drilling Fluids and Wastes
3. Fluids from Hydrogen Sulfide Abatement
4. Other

WORK GROUP NO. 5

Well Completion and Production

1. Casing
    - Thermal Stress
    - Corrosion and Erosion
2. Cements
    - Thermal Stress
    - Chemical Stability

WORK GROUP NO. 6

Systems, Components and Materials

1. Pipelines and Power Plants
    - Materials and Components
        - Corrosion
        - Erosion
        - Control Valves
        - Instruments
2. Systems Design
    - Automatic Controls
    - Back up and Bypass Systems
    - Condensers

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