452
2-17-81
JMB

DC-2 302

DOE/ID/12049-3

(1)

P-2030

MASTER

MUNICIPAL GEOTHERMAL HEAT UTILIZATION PLAN FOR GLENWOOD SPRINGS, COLORADO

Final Report

December 31, 1980

Prepared by
University of Denver
Denver Research Institute
Denver, Colorado

Work Performed Under Contract
No. DE-AS07-79ID12049.M002
for the Idaho Operations Office

U. S. DEPARTMENT OF ENERGY

Geothermal Energy

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

Printed in the United States of America

Available from
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161
NTIS Price Codes: Printed Copy A13
Microfiche A01

DISCLAIMER

This book was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product or process disclosed, or represents that its use would not infringe privately owned rights. References herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Municipal Geothermal Heat Utilization
Plan for Glenwood Springs, Colorado

Final Technical Report

Prepared by

University of Denver
Denver Research Institute
P.O. Box 10127
Denver, Colorado 80208

December 31, 1980

Prepared for the

Idaho Operations Office
U.S. Department of Energy
Division of Geothermal Energy

Contract No. DE-AS07-79ID12049.M002

DISCLAIMER

This book was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Acknowledgements

This report is the product of the efforts of many researchers at DRI and under subcontract. Mr. James Butz was Principal Investigator, responsible for overall direction of the projected integration of the individual contributions into a cohesive final report. Mr. Matt Holden and Mr. Bob Gyepes prepared much of the analysis of the geothermal system hardware and cost estimates. Mr. Lee Olver was responsible for the economic evaluation. Institutional aspects of legal and environmental issues were ably handled by Mr. Ralph Williams and Ms. Jackie Maddox. Mr. Jay Dick of Chaffee Geothermal, Ltd, wrote the resource analysis, with a geochemistry contribution by Dr. Joan Fitzpatrick of DRI. Mr. King Lloyd, City Engineer for the City of Glenwood Springs proved to be a valuable liaison and made a significant contribution to the Load Analysis. Two additional subcontracts were let to investigate the effects of disposal of the geothermal effluent through waste water treatment processes. Mr. Dennis Sandretto of CH2M-Hill's Denver Office directed the conventional sewage treatment impact study and Dr. Chris Alsten of the Applied Aquatics Resources Institute performed the study on aquaculture treatment systems impact. Finally, the support of the Department of Energy's Idaho Operations Office should be recognized. Mr. Lynn Nelson of EG&G Idaho (as designated project officer) proved to be a valuable resource person, and suggestions from Mr. Bob Chappell and Mr. Mike Tucker at the several contract review meetings were quite helpful.

TABLE OF CONTENTS

	<u>Page</u>
Abstract	ix
I. Overview	1
II. System Design and Optimization	
A. Load Analysis.	13
B. Design Philosophy.	21
C. System Configuration	23
D. Heating System Performance and Retrofit Design	52
E. System Capital Cost Summary.	59
F. Disposal Alternatives.	65
III. Economic Evaluation	
A. Method of Analyses	71
B. Basic Assumptions.	75
C. Base Case Analysis	79
D. Sensitivity Analyses	82
E. System Financing	90
F. Pricing Issues	96
G. Summary and Conclusions.	98
IV. Geothermal Resources	
A. Resource Assessment.	101
B. Proposed Geothermal Exploration Program.	136
C. Drilling and Reservoir Engineering	143
D. Reinjection of Geothermal Fluids	157
V. Institutional	
A. Operating Entity	173
B. Institutional Aspects.	174
C. Glenwood Geothermal Task Force	181
D. Expansion Potential.	182
Appendices	
A. CH ₂ M-Hill Conventional Sewage Treatment Geothermal Impact Report	187
B. Applied Aquatics Resources Institute Report on Geothermal Fluid Impact on Aquaculture Waste Treatment Systems.	221
C. Permits and Regulations.	243
D. Directory of Potential Sources for Materials and Equipment.	259
E. Bibliography and References.	263

LIST OF FIGURES

	<u>Page</u>
II-1. Proposed Well Site	19
II-2. Schematic of Proposed System	27
II-3. Typical Pump Performance Curve for Distribution Loop.	40
II-4. Air-Side Performance at Reduced Water Inlet Temperatures	54
II-5. Comparison of Geothermal Radiator Performance and Heat Demand as a Function of Ambient Temperature.	55
III-1. Comparison of Annual Heating Costs: Base Case	84
IV-1. Location of hot springs at Glenwood Springs.	102
IV-2. Detailed geologic map of Glenwood Springs vicinity	104
IV-3. Proposed geologic cross-section through the Glenwood Springs area.	107
IV-4. Vector plots of waters from Glenwood Springs	111
IV-5. Glenwood Springs Water Analyses.	113
IV-6. Log-Activity Reaction Plot for the Solution of Gypsum and Calcite at Glenwood Springs	118
IV-7. Known Redox Potentials vs pH for Geothermal Waters Worldwide	120
IV-8. Residual soil mercury map of Glenwood Springs.	122
IV-9. Aeromagnetic map of the region around Glenwood Springs	124
IV-10. Dipole-dipole electrical resistivity survey at Glenwood Springs.	122
IV-11. Geothermal temperature gradient map of the the region around Glenwood Springs	128
IV-12. Locations of 37 surface gradient map of the region around Glenwood Springs	137

LIST OF FIGURES (Continued)

	<u>Page</u>
IV-13. Locations of the three previously proposed magneto-telluric/Schlumberger electrical resistivity depth sounding stations as they relate to the projected geothermal resources at Glenwood Springs, Colorado	139
IV-14. Geothermal target areas for detailed geologic mapping. Exploration is limited to the western geothermal target area only	141
IV-15. Anomalous geothermal resource areas in Glenwood Springs	143
IV-16. GS 9-1 Well Profile	145
IV-17. Proposed plan-view of the geothermal drilling site . .	147
IV-18. GS 9-1 drilling stack	149
IV-19. GS 9-1 Wellhead Completion Assembly	151
IV-20. Sketch of test well GS 9-1	155
IV-21. Location of Two Rivers Park site	162
IV-22. GS 9-2R Well Profile	164
IV-23. Slotted height for various flow rates and permeabilities with no extra pumping	168
V-1. Questionnaire and Results	183

LIST OF TABLES

	<u>Page</u>
II-1. System Performance at 30°F Ambient Design Point for 1978 Weather Data	15
II-2. Summary of Heat Load Calculations for Glenwood Geothermal Project	18
II-3. Current Heating System Data	20
II-4. Distribution System Costs	37
II-5. System Pump Specifications.	42
II-6. Peaking Subsystem Cost	46
II-7. Retrofit Cost Optimization.	60
II-8. Cost Summary for Proposed System Options.	61
III-1. Retrofit Costs as a Function of Retrofit Method and Wellhead Temperature for a Base Case	74
III-2. Basic Economic Assumptions.	76
III-3. Levelized Life Cycle Costs for Base Case System	80
III-4. Annual Cash Flow Statement for Base Case Systems.	83
III-5. Present Value of System Savings (1980 \$) as a Function of System Size and Natural Gas Price Scenario.	86
III-6. Present Value of System Savings (1980 \$) Capital Cost and Gas Price Scenarios for Option B.	87
III-7. Present Value of System Savings (1980 \$) as a Function of Operating Costs and Gas Price Scenarios for Option B.	89
III-8. Present Value of System Savings (1980 \$) as a Function of the Debt Ratio for Option B.	91

LIST OF TABLES (Continued)

	<u>Page</u>
III-9. Present Value of System Savings (1980 \$) as a Function of Wellhead Temperature For Option B.	92
IV-1. Specification of ions	114
IV-2. Minor and Trace Ion Chemistry	117
IV-3. Recommended Analytical Methods to Estimate Geothermal Reservoir Characteristics	158

Blank

ABSTRACT

A study has been made of the engineering and economic feasibility of utilizing the geothermal resource underlying Glenwood Springs, Colorado to heat a group of public buildings. The results have shown that the use of geothermal heat is indeed feasible when compared to the cost of natural gas.

The proposed system is composed of a wellhead plate heat exchanger which feeds a closed distribution loop of treated water circulated to the buildings which form the load. The base case system was designed to supply twice the demand created by the seven public buildings in order to take advantage of some economies of scale. To increase the utilization factor of the available geothermal energy, a peaking boiler which burns natural gas is recommended. Disposal of the cooled brine would be via underground injection. Considerable study was done to examine the impact of reduced operating temperature on the existing heating systems. Several options to minimize this problem were identified.

Economic analyses were completed to determine the present values of heat from the geothermal system and from the present natural gas over a 30 year projected system life. For the base case savings of over \$1 million were shown. Sensitivities of the economics to capital cost, operating cost, system size and other parameters were calculated. For all reasonable assumptions, the geothermal system was cheaper. Financing alternatives were also examined.

An extensive survey of all existing data on the geology of the study has led to the prediction of resource parameters. The wellhead temperature of produced fluid is suspected to lie between 140° and 180°F (60° and 82°C). Flowrates may be as high as 1000 gpm (3800 liters per minute) from a reservoir formation that is 300 ft. (90 m) thick beginning about 500 ft. (150 m) below the suggested drill site in the proposed Two Rivers Park. This land is owned by the City of Glenwood Springs. Chemical

analyses of several hot springs in the vicinity suggest that the waters in all the springs are of a common origin, implying a reservoir of considerable size. For this reason, little or no impact on existing hot springs would be expected from a successful production well.

State regulation of geothermal development in Colorado is somewhat confused since a geothermal resource is treated as neither water nor mineral, yet possesses attributes of each. Nonetheless, a suggested procedure for development of the Glenwood Springs geothermal resource is presented. The permits needed for well drilling and injection and the agencies responsible for their issue have been identified. The sequence for a federal Environmental Impact Statement or Report is also noted. Information on current uses and adjudications for existing hot springs is included.

The recommended action is to secure commitments for future demand sufficient to accept the risk of drilling an exploratory well and then to go ahead and drill. The decision to build the rest of a geothermal heating system in Glenwood Springs can be made only after the quality and capacity of the resource is known.

I. OVERVIEW

The City of Glenwood Springs, Colorado, lies 150 miles (240 km) west of Denver at the confluence of the Colorado and Roaring Fork Rivers. The town is named after an occurrence of natural hot springs, which are located along side the Colorado River. The largest of these, the Yampah, flows at a rate of 2200 gallons per minute (8300 liters per minute), and has been known for 120 years. The waters of the Yampah spring have been used in a spa for over 100 years, and the area was a gathering place for Indians prior to that time. The community now has about 9000 residents and is experiencing significant growth along with the entire Western Slope of the Colorado Rockies, an area rich in energy minerals.

Recently, the Denver Research Institute entered into a contract with the Idaho Operations Office of the U.S. Department of Energy, Division of Geothermal Energy to conduct an engineering and economic feasibility study for a geothermal direct heat utilization project in Glenwood Springs. The subject of this effort is a mini-district heating system, which is comprised of seven public buildings in the downtown area of the city. Included are the City Hall complex, County Courthouse, County Sheriff's Office, U.S. Forest Service Building, City Maintenance Shops and a newly built Sewage Treatment Facility. This last building encloses the primary treatment system, a new process known as Rotating Biological Disc (RBD). In order for the biological agent on the rotating discs to remain active, the air temperature in the RBD building must be maintained between 60°F (16°C) and 95°F (35°C). The City of Glenwood Springs is considered a prime candidate for direct use geothermal development because of the extensive surface manifestations of the resource and because of growing local interest in the utilization of that resource.

A heat load analysis was performed on the above buildings in order to define the minimum size of system required to meet peak demand. The types of heating system currently used in each of the buildings was also noted so that any equipment retrofit needed to allow use of the distributed hot

water from the geothermal system. Glenwood Springs has an annual heat load of 6500 degree (F) days, and a recommended minimum design temperature of -5°F (-21°C). The energy required to heat the seven buildings, which total 75,000 square feet (7000 m^2) is about 9 billion Btu per year (2.7 million kW-hr).

System Configuration. Several alternative system designs were evaluated, and the candidate found most appropriate for the load and predicted reservoir conditions was studied in greater detail. The chosen system features a heat exchanger located at the wellhead and a closed distribution loop where clean, treated water is heated by the geothermal brine and circulated to the buildings served by the system. After passing through the heat exchanger, the geothermal brine is reinjected for disposal. The geothermal heat exchanger is sized to provide one half of the peak load, with the other half supplied by a fossil-fueled peaking boiler. Since peak loads are experienced so little on an annual basis, calculations show that the base-loaded geothermal heat exchanger would supply about 90% of the annual energy consumption for the system.

This design presents many advantages for the particular application under study. By circulating clean, treated water in the heating systems of the individual buildings, problems with corrosion and scale buildup due to the dissolved solids content of the geothermal brine are avoided. The penalty paid for this is a temperature in the circulating water that is slightly reduced from the geothermal maximum due to the use of a heat exchanger. The use of a fossil peaking boiler allows the supply temperature of the geothermal system to be more closely matched to the required performance of heat emitters. The peaking boiler raises the temperature of the circulated water above the value at the outlet from the heat exchanger only when the geothermal heat exchanger is operating at full capacity; by supplying hotter water to the separate building heating units (radiators, fan convectors, etc.), their heat output is increased at a time when most needed - when ambient temperatures are near the design minimum and demand is approaching its maximum.

The performance of existing heating systems under the expected lower temperature was studied. As a result, two types of equipment modifications (retrofit) have been identified. Buildings that currently employ air to air heat exchange systems, all fired with natural gas, will need to have those units replaced with water to air heat exchange equipment; this mandatory retrofit will be required for about 1/3 of the total capacity in the seven buildings. For the remainder, the circulating hot water can be flowed through existing heat emitters. However, because of the expected reduction in temperature from current boiler levels, the presently installed equipment may not satisfy peak demand. One solution to this problem is to install additional heat emitters to supply the shortfall. These units are chosen to have optimum performance at the lower temperature; however, their purchase and installation adds to the cost of the geothermal system. An alternative is to reduce the demand to match the performance of the heat emitters by instituting a number of conservation measures. Results of a recent study on an older building in Glenwood Springs indicate that the conservation option is indeed feasible; its chief merit is that building modifications literally pay for themselves in reduced energy consumption. The choice between conservation and installation of additional equipment has been termed discretionary retrofit.

Chief components of the geothermal system are a plate heat exchanger, insulated distribution piping, peaking boiler, and pumps for both the circulating water and geothermal brine. A plate heat exchanger was chosen for its low cost, high heat transfer coefficient, ease of maintenance and resistance to fouling. The distribution piping is insulated for the supply line and uninsulated for the return line because it is important to minimize temperature drop enroute to the buildings, but not cost-effective for the cooled water being circulated back to the heat exchanger. The peaking boiler is fired with natural gas; its inclusion in the design permits a high utilization factor for the geothermal wells, which is important because of their relatively large capital cost. Pumps for the system have been specified with reliability and the effects of the geothermal brine on materials in mind. Valves, controls and other system components have not been examined in detail.

The base case system was designed to service a peak demand twice that of the seven buildings included so as to take advantage of significant economies of scale. It would provide a peak supply of 10 million Btu/hr (3 MW thermal) at a flowrate for geothermal brine and circulated water of 500 gallons per minute (1900 liters per minute) each. The design temperature drop in the geothermal brine is 20°F (11°C), the same as the temperature rise in the circulating water. The proposed system is designed to accomodate expansion with minimum modification.

The final question addressed in the engineering study was that of disposal. Several alternative methods were examined, and underground injection deemed to be the best choice. Surface disposal was severely impacted by the high dissolved solids content of the resource expected to be about 20,000 parts per million. Interesting studies of disposal through conventional and aquaculture waste water treatment systems were also carried out under subcontract, and are presented as appendices to this report.

Economic Evaluation. The economic feasibility of the base case system configuration was evaluated using levelized cost and present value methodologies. The sensitivity of the results to changes in a number of key parameters was also examined. Several different methods of funding the construction of the geothermal system were found to be available to the City; the economic advantages and disadvantages of each of the alternative methods were also investigated. However, no attempt was made to assess the political desirability of the alternatives.

The system boundary was drawn to encompass all components of the complete geothermal heating system, including mandatory retrofit, but excluding discretionary retrofit costs for individual buildings. As part of the analysis, operation and maintenance costs were calculated to include labor, pumping electricity, fossil peaking fuel, insurance and in-lieu-of-tax charges.

The approach used to conduct the majority of the economic analysis was to first estimate the present value of the natural gas to be displaced

by the geothermal system. That value was then compared with the present value of the total costs (including operation and maintenance costs) of the geothermal system. The difference between the two present values represents the present value of systems savings.

The calculated present value of system savings for the base case system is \$1,079,668. Cash flows for each of the 30 years of projected system life were also computed. The system shows a small positive cash flow from the start which builds to a net of \$128,096 in the thirtieth year.

The sensitivity of changes in the above result to changes in the forecast price of natural gas, capital cost, operating cost, debt ratio and well-head temperature was also examined. It was found that the base case system is economically feasible under any reasonable set of assumptions. Further definite economies of scale are realized in the base case over the system which meets only the demand of the seven buildings in the study. A system larger than the base case shows an even more favorable advantage over the existing natural gas heat.

The construction of a geothermal heating system over an unproven resource will be considered to be risky by investors. The city could thus encounter difficulties raising by conventional methods the \$759,000 estimated as the initial capital cost of the basecase system.

The City of Glenwood Springs has several sources of funds available to it: city cash reserves, general obligation bonds and revenue bonds. In addition, the U.S. Department of Energy is sponsoring two programs which seek to lower the risk of developing geothermal resources. By lowering the risk seen by investors, DOE hopes to make more private funds available at lower interest rates than would otherwise occur.

The two DOE-sponsored programs the User-Coupled Confirmation Drilling Program (UCCDP) and the Geothermal Loan Guarantee Program (GLGP) operate

in different ways. The UCCDP will pay up to 90% of the cost of an unsuccessful well; thus decreasing the downside risk. The GLGP will guarantee up to 75% of the cost of a geothermal project, subject to certain conditions.

Finally, the possibility of having a private developer accept the risk of developing the resource and selling the geothermal fluid to the city must be considered. The city would then own and operate the heating system, except for the wells.

A number of funding sources and incentives exist. Choice of a particular method will require additional analysis and the direct involvement of the city. It is likely, however, that the funding method ultimately adopted could very well be a combination of the methods and programs discussed above.

Resource. The primary intent of the geological and resource study of the Glenwood Springs geothermal project was to develop a feasible geothermal resource model and to design a drilling and testing program to develop the resource. A resource model is projected herein based upon existing geological, geophysical and geochemical data and information. No new data has been developed through field exploration surveys.

Geological studies of the Glenwood Springs area lend evidence that the geothermal reservoir is primarily within the Leadville Limestone (Mississippian). This formation is a highly porous and permeable limestone unit of approximately 300 feet (90 m) in thickness and is dipping steeply at 40° to the southwest. Where the Leadville is near the surface and covered by alluvial gravels numerous hot spring vents discharge along a one mile segment of the Colorado River within town. Geological cross-sections constructed from existing geologic maps and studies show that the Leadville could be encountered at a depth of approximately 500 feet (150 m) within the City of Glenwood Springs. It would be ideal to drill into the Leadville at this depth so as to 1) encounter geothermal fluids at elevated temperatures prior to near surface cold water mixing, and

2) be sufficiently deep and at a great enough distance from existing hot springs to reduce potential impact on temperature.

Two significant areas of anomalous geothermal activity have been delineated; these areas represent the regions with the greatest geothermal drilling potential and are based on shallow electrical resistivity geophysical surveys and the locations of hot spring vents. Anticipated subsurface reservoir temperatures range from 140° to 180°F (60° to 82°C). These projections are supported by surface temperatures of 125°F (82°C). Projected flow rates from the initial geothermal exploration well are estimated to be 1000 gpm (3800 lpm). This is a "best guess" based upon total hot springs discharge in excess of 3000 gpm (11,400 lpm) from all hot springs vents; the Yampah Hot Spring alone has greater than 2200 gpm (8400 lpm) of discharge.

Formation:	Leadville Limestone (2)
Reservoir depth:	500 feet [150 m] (2)
Reservoir thickness:	300 feet [90 m] (2)
Areal extent:	$\frac{1}{2}$ to 2 square miles [130 to 520 hectares] (3)
Subsurface Temperature:	140° to 180°F [60° to 82°C] (3)
Flow rate per well:	1000 gpm [3800 lpm] (1)

The validity of the reservoir projections is shown by the number in parentheses. This validity rating is defined as follows:

- 3 - Very confident in the accuracy of the projected data, greater than 50% validity.
- 2 - Sufficient data to indicate the possibility of these characteristics, approximately 50% validity.
- 1 - Some data to indicate these characteristics; a "best guess" at the accuracy of the projection.

Prior to actual drilling of a geothermal exploration well it is imperative to conduct additional exploration surveys to further delineate a geothermal reservoir target. A suggested exploration program would include a close-grid gravity survey to outline fault zones and subsurface geological units. Detailed surface mapping and hammer seismic work are

suggested as useful in choosing a candidate drill site. Finally, it is thought that angled mineral cores may be drilled to intersect any faults or fractures with surface manifestations. As an alternative, a slim hole may be drilled down to the suspected reservoir, the Leadville limestone, to define the stratigraphy and to determine fluid temperature.

From existing resource data and the geothermal reservoir model outlined in this project, a well site has been picked for the geothermal exploration/production well. City-owned land at the proposed Two Rivers Park site is ideal for all drilling activities. At this location a full-bore (9-5/8") exploration/production well will be drilled to 800 feet (244 m) through the Leadville Limestone and is anticipated to produce 1000 gpm (3800 lpm) of artesian flow. Also at this location a 4½" reinjection well can be drilled to 1600 feet (488 m) into the Sawatch Quartzite (Cambrian).

Reservoir tests will be conducted on both the production and reinjection wells and existing wells in the vicinity (hot and cold) will be monitored for temperature, pressure and flow rate fluctuations during testing. It is anticipated that flow tests on the production well will have minimal to no impact on existing hot springs and wells due to the depth of production and the distance from the well to hot springs vents. Reinjection testing should have no effect on the existing hot water regime since the reinjection zone is 700 feet (213 m) below the Leadville Limestone and the two zones are separated by 250 feet (76 m) of quartzites and 450 feet (137 m) of confining shales and limestones.

Institutional/Environmental Aspects. The Colorado Geothermal Resources Act vests authority in the Oil and Gas Commission for the issuance of drilling permits for geothermal energy. The State Engineer becomes involved because the Act preserves existing water laws and rights under the Appropriation Doctrine. If subsurface disposal of the spent fluids are considered then the State Public Health Department issues its approval through the permit process.

Under the Appropriation Doctrine a water user may establish rights to water by adjudication in court. Several users in the Glenwood Springs area have done this on geothermal effluents (primarily springs). The proposed site for the municipal well was deeded to the City of Glenwood Springs, but the mineral rights were excluded. Because of the State's ambivalent approach to geothermal resources, it is suggested that Glenwood Springs obtain permission from the original landowner to extract the geothermal energy. After filing all of the required State permits and upon completion and flow testing of a confirmation well, the city should file for adjudication of flow to protect its rights against future development.

A Task Force was created early in the program to provide DRI with local input. The group was composed of local representatives of the city, county, and Federal agencies, the school districts, developers, the private sector, and interested residents. The Task Force primarily concentrated on public attitudes and potential uses (and users) of geothermal energy. The main concern of the Task Force has been the effect that development would have on the Hot Springs swimming pool (a major tourist attraction). Generally, the local attitude toward geothermal development and use is favorable.

The environmental requirements for a geothermal project in Glenwood Springs depends upon the state environmental regulation and the degree of Federal involvement. If the project proceeds with Federal funding then a lead agency will be designated and will supervise the preparation of any required environmental reports. If the city does not seek Federal support, then the environmental requirements are supervised by the Colorado Department of Health. In either case, effluent disposal (either surface or subsurface) will require a permit from the state of Colorado.

In 1978, DRI prepared a preliminary environmental report for the state concerning geothermal development at Glenwood Springs. While this study was not site specific, no significant adverse environmental effects were found.

Recommendations. This study shows that a geothermal district heating system for the public buildings in the downtown area of Glenwood Springs is quite feasible. If the load of additional buildings can be incorporated into the system the economics are even more favorable. Several alternatives for financing construction of the system have been identified, as have the legal and environmental permits that are needed.

If these results are to be translated into an operating system, the primary goal must be to drill a well to confirm the existence of a resource sufficient to supply the required quantity and quality of geothermal waters. Certainly, there is an element of risk in such a venture, however, there is an alternative which provides a sizable Federal government subsidy if the resource fails to measure up; there is also the possibility of transferring this risk to a private developer, with some slight increase in energy cost as compensation for the risk, if successful.

The decision to drill an exploratory well should be preceded by a potential users survey to ensure that sufficient load is available for construction of a system of economic size. The city itself, along with other public buildings in the downtown area, can provide a sizable portion of this load. It would be preferable to obtain written commitments on the part of all interested potential users to participate in the system. Of course protection for such interested parties in the form of maximum energy cost guarantees would seem appropriate in return for their assured participation. All parties would be relieved of their respective obligations if the resource could not meet minimum performance standards.

In conjunction with the market survey, it will be necessary to complete financing arrangements before drilling can begin. To this end, it is suggested that early contact be made with officials of two Department of Energy assistance programs - the User Coupled Confirmation Drilling Program (UCCD) at the Idaho Operations Office, and the Geothermal Loan Guarantee Program (GLGP) at the San Francisco Operations Office. The

goal of these discussions which should include the City Attorney and bond counsel, would be to define the advantages and drawbacks of the various financing options and thus develop a viable plan on which to proceed with the drilling.

Once the initial well is drilled, testing will determine the temperature, flow capacity and chemical content of the geothermal waters. With this data the detailed design of the system can be completed utilizing the engineering feasibility work included in this report.

Blank

II. SYSTEM DESIGN AND OPTIMIZATION

A. Load Analysis

Space heating of buildings presents a seasonal load that varies from peak demand in winter months to virtually no demand in the summer. There is, superimposed upon the annual cycle, a diurnal variation with peak demand in the predawn hours. A geothermal heating system is capital intensive, with very low operating costs. Therefore economic benefit of the geothermal system is maximized when its output is utilized for a large percentage of the year.

At first glance, then, it appears that the geothermal supply and space heat demand are incompatible. One solution that has been proposed for this problem is to use the geothermal system to supply only a portion of the peak demand, so that a greater percentage of the geothermal capacity is used at times of reduced demand, such as in spring and fall. The additional heat required on the coldest winter days can be supplied by a fossil fueled boiler that is used only a small fraction of the year.

To begin the load analysis, summaries of weather data for Glenwood Springs collected by the U.S. Weather Service were obtained for the past three years. The city was found to have an average annual heating requirement of about 6500 degree (F) days. This is a measure of the annual heat demand where 1 degree (F) day represents an ambient (exterior) temperature 1°F (0.6°C) below a set value (65°F or 18°C) for a period of 24 hours. For example, if the ambient temperature was constant at 40°F (4°C) for 24 hours, the daily heat demand for that location would be 25 degree (F) days. The data presented monthly heat demand values as well as the average of daily mean, maximum and minimum temperatures for the month.

The average temperatures were used to perform calculations as a basis for selection of the minimum ambient temperature for which the

geothermal heat exchanger would meet the system demand. The analytic method was to assume a sinusoidal distribution about the average monthly temperature with amplitude equal to the maximum and minimum values given in the data. A geothermal system design temperature line then was plotted to intersect this representative daily temperature distribution. The geothermal system supplies the entire energy demand for exterior temperatures at the design point and above. The system is operating at 100% capacity at the design point; for exterior temperatures below the design point, the fossil fuel boiler is used to supply the additional heat demanded.

Calculations were made to determine the quantity supplied by the geothermal system for each month. Since the total required degree (F) days were also known, it was then possible to compute the percent of annual demand which the geothermal system could supply. Given a geothermal system design temperature, a simple computation for design capacity can be made:

$$\frac{[65^{\circ}\text{F} - T_{\text{geothermal system design}}] \cdot \text{no. of days/month}}{\text{degree F} \cdot \text{days design capacity}} =$$

System utilization, defined as design capacity divided by available supply, was determined. This is an important parameter, since the utilization of the system as a function of available capacity has a significant impact on the amortization of system capital costs over the actual energy provided by the system.

Analyses were made for two years of available weather data and at two geothermal system design temperatures. Sample results are shown on Table II-1. For a 30°F (-1°C) geothermal design temperature, the calculations reveal that about 90% of the annual demand is supplied by the geothermal (base-loaded) system, which is utilized to about 50% of capacity. Similar results were obtained for 1977 data. When the exercise was repeated using 20°F (-7°C) for the design temperature, the geothermal system supplied 98% of the annual demand; however, utilization dropped to 40% of capacity. Studies done at the Geo-Heat Utilization

TABLE 11-1

SYSTEM PERFORMANCE AT 30°F AMBIENT DESIGN
POINT FOR 1978 WEATHER DATA

Month	Degree (F) Day Demand	Geothermal System Supplied (Degree (F) Day)	% Demand Supplied by Geothermal Source	Geothermal Design Capacity (Degree (F) Day)	Geothermal Utilization Factor (% of cap.)
Jan.	1127	1035	91.8	1085	95.4
Feb.	967	881	91.1	980	89.9
Mar.	757	750	99.1	1085	69.1
Apr.	548	548	100.0	1050	52.2
May	378	378	100.0	1085	34.3
Jun.	51	51	100.0	1050	4.9
Jul.	0	0	100.0	1085	0
Aug.	47	47	100.0	1085	4.3
Sep.	159	159	100.0	1050	15.1
Oct.	367	367	100.0	1085	33.8
Nov.	741	735	99.2	1050	70.0
Dec.	<u>1398</u>	<u>1085</u>	<u>77.6</u>	<u>1085</u>	<u>100.0</u>
	6540	6036	92.3	11875	50.8

Center at the Oregon Institute of Technology and by others note that to be cost effective, geothermal systems need to maximize utilization. At levels below 50%, it becomes quite difficult to demonstrate economic feasibility; below 40%, it is virtually impossible. For this reason, the 30°F (-1°C) design temperature was chosen as the value to be used in the design of the system hardware.

An additional comment on the analysis of weather data is in order here. The approach taken gives only approximate results because of the use of average temperatures. Calculations for heat demand satisfied by the system and utilization factor will be slightly exaggerated due to the tendency of the averaging technique to minimize the impact of particularly cold weather. However, the occurrence of weather extremes is rare; for example, in Denver (where detailed data is available), the temperature is below 3°F (-16°C) only 2 1/2% of the time in the period December through February. The fact that a building heating system operates at its full design capacity for an extremely limited time on an annual basis must be emphasized. This realization then leads to the conclusion noted here that the geothermal part of any system must be base-loaded since it is a capital-intensive investment.

The next step in the Load Analysis was to obtain data on the public buildings that would provide the load for the geothermal system. An on-site inspection was made of each of the facilities. Current heating systems were examined, and information on materials of construction, dimensions and areal extent of doors and windows was recorded. Detailed calculations of the heat loss paths for each of the structures were made following procedures and using values for coefficients of transmission as suggested in the ASHRAE Handbook of Fundamentals, chapter 20. Where materials of construction were unknown, a "best guess" assumption was used. As a final check on the results, a comparison with the nameplate rating of the current heating system was made. All calculated values seemed reasonable on this basis.

A summary of the results of the building heat load analysis is presented in Table II-2. Note the design minimum temperature for heating in Glenwood Springs employed in the calculations is -5°F (-21°C), as given by several local architectural engineering firms there. The total peak load (heating only) on the system is 4.2 million Btu per hour (1.2 MW thermal) at the -5°F design point; a second load calculation is presented for 30°F (-1°C), the lowest ambient temperature at which the geothermal portion of the system supplies the entire demand. The buildings included in the study total over 77,000 ft^2 (7200 m^2) of floor space to be heated with geothermal energy. The locations of the buildings included in the study are shown as circled numbers 2 through 8 on Figure II-1; the proposed well site is designated with an "X".

Current heating systems installed in these buildings encompass most technologies in use today. The Post Office and Forest Service building use hot water convectors, a technique which can be converted to a geothermal source by a simple, straightforward procedure. The Glenwood Springs City Hall has a central air handler supplied by a hot water coil; and the County Courthouse is heated with low pressure steam. Both of these can also be modified to use the geothermal water. Gas-fired forced air unit heaters are used in large open spaces at the sewage treatment plant and Fire Department. Electric baseboards are used in the administrative offices of the Sewage Treatment Facility. Forced-air gas furnaces are installed at the County Sheriff's office. It is recommended that the radiators currently used in the city maintenance shops be replaced with fan-coil units, which are more suited to heating large open areas. A breakdown of existing heating systems by type is given in Table II-3. Most of the buildings also possess gas-fired hot water heaters for domestic consumption. The demand for these units is not included in the system total load noted above.

Where current systems are not convertible to geothermal, replacement hot water equipment has been identified. Units for the large open areas as well as room sized are available from a number of manufacturers. Estimated costs for the needed retrofit have been made and are included

TABLE 11-2

SUMMARY OF HEAT LOAD CALCULATIONS
FOR GLENWOOD GEOTHERMAL PROJECT

<u>Building</u>	<u>Total Floor Area</u> ft ²	<u>Calculated HLF</u> Btu/hr-°F	<u>Demand at 30°F Exterior Temp</u> Btu/hr	<u>Demand at -5°F Exterior Temp</u> Btu/hr
County Courthouse	18,500	14,615	510,000	1,020,000
Sheriff's Dept.	6,400	4,373	153,000	306,000
Sewage Treatment	9,790 ft ²	7,409	259,000	518,000
City Shops	3,000 ft ² (est)	--	150,000 (est)	300,000 (est)
City Hall	10,000 ft ² (est)	8,753	306,000	612,000
Forest Service	15,375	9,661	340,000	680,000
Post Office	12,044	10,351	<u>363,000</u>	<u>726,000</u>
TOTAL SYSTEM GEOTHERMAL LOAD			2,081,000	
			TOTAL MAXIMUM SYSTEM LOAD	4,162,000

Heat Loss Factor: Weighted sum of resistances of building components
(walls, ceiling, windows, etc.).

FIGURE II-1: City of Glenwood Springs
Circled numbers mark public buildings surveyed.

TABLE II-3

CURRENT HEATING SYSTEM DATA

<u>Building</u>	<u>Heat Supply (By Type) in Btu/hr.</u>			
	<u>HLF</u>	<u>Radiator (Steam and Water)</u>	<u>Gas Fired Air to Air</u>	<u>Electric Baseboard</u>
County Courthouse	14,615	1,020,000		
Sheriff's Dept.	4,373		306,000	
Sewage Treatment	7,409 (5272+2137)*		370,000	150,000 Btu/hr.
City Shops	4,000	(300,000)**	300,000 Btu/hr.	
City Hall	8,753 (5252+3501)*	368,000	245,000	
Forest Service	9,661	680,000		
Post Office	<u>10,351</u>	<u>726,000</u> Btu/hr.		
	59,162	2,794,000 Btu/hr.	1,221,000 Btu/hr.	150,000 Btu/hr.

Total Btu/hr. = 4,162,000

Radiator Building HLF = 39,879

(HLF = Heat Load Factor: a measure of Peak Heat Demand for buildings in the system)

*Indicates HLF split between the two heating system modes.

**Recommendation is to replace current radiators in shop facility with fan-coil units during geothermal conversion.

in Section IID. An interesting concept has been developed to limit retrofit of additional radiator area in present hot water systems. Performance of these systems will be reduced if the temperature of the geothermally heated circulating water is below current operating levels; however demand for these buildings can be reduced via conservation measures to match system output. The unique feature of the conservation approach to matching supply and peak demand is that cost of the required building modifications can be recovered from energy savings, so that no conservation retrofit costs are included in the capital cost of the geothermal system for purposes of economic analysis.

B. Design Philosophy

In approaching the preliminary design of the geothermal direct heat system to be used in Glenwood Springs, several principles were developed which formed a guiding philosophy. These key concepts included the following:

- System Reliability - Since the system would be a utility, reliability is a primary criterion. Choice of materials and type of equipment must be made with this in mind. The system should be designed with adequate safeguards and controls to permit continued operation (at reduced output) if there were failures in any of the pumps or the heat exchanger. Backup systems should not be required in any of the buildings served.
- Ease of Maintenance - The brines in Glenwood Springs have a high dissolved solids content and could present significant scale problems in pumps, piping and heat exchange equipment. Components and overall design should be evaluated on the relative ease and frequency of maintenance needed for proper operation of the system. Adequate periodic maintenance on the equipment also reduces the risk of failure and thus enhances reliability of the system.

- Provision for Expansion of System - The heating load to be supplied by the geothermal system consists of a number of public buildings in the downtown Glenwood Springs area. It should be anticipated that once feasibility of system operation is established there will be interest among the general population to expand the system. This is particularly significant in light of the projected capacity of a single well noted in the resource assessment (Section IV). Specification of equipment types and sizes that allow for increase in system operating capacity with minimal impact on other components and energy users is important. Economic viability of the system may be much stronger if full use of the well energy capacity can be made at some future date.
- Maximum Utilization of Existing Equipment - In the design of the system, existing heat emitters and building heating system configurations must be considered. Flow rates of the system circulating fluid and temperature drop are limited by the design and surface area of present equipment. Candidate system configurations should provide alternatives which account for heat transfer properties of the existing heating systems. For example, it seems better to boost the maximum temperature of the system circulating fluid to meet peak demand, rather than to increase flowrate. This is due to the nature of the heat transfer at the radiator surface.
- Minimum "Life Cycle" Cost of System - When alternatives are available in the specification of hardware components, decisions should be made on a life cycle cost basis, rather than on initial investment. This evaluation technique is also important on a system level - there will be tradeoffs between components in terms of size or capacity which must be resolved in favor of the option that presents the lowest life cycle cost to the overall system.

The above criteria were used in development of the system design alternatives as well as in their evaluation and integration to produce a final design approach which highlights the features described above, yet maintains an economic investment level. Details of the system configuration are presented in the following section.

C. System Configuration

The suggested geothermal district heating system designed for Glenwood Springs is presented in this section. It is recommended that a small building be erected near the production well to house the following components of the system: heat exchanger, circulation pumps, reinjection pumps, peaking boiler and system controls. If found to be necessary, equipment for treatment of the geothermal brine prior to reinjection could also be located in this structure. A concrete foundation to support the heavier pieces of equipment would be necessary, and the building would be warmed by the heat lost from the various components inside, especially the heat exchanger. The various system sizes do take into account heat lost in the piping network as well as in the operating components, reflected in a 20% increase in the gross system capacity as compared to the net demand.

Candidate Designs. There are four general configurations that were examined for use in the proposed district heating system. Upon consideration of the design philosophy as well as the predicted properties of the fluid and reservoir, a preliminary evaluation of the candidates resulted in the elimination of two from further consideration. The remaining two configurations were then subjected to an engineering and economic evaluation where the heat pump based system was shown to be more complicated and less suited to the application than the selected system, which features heat exchange from the geothermal source to a closed loop that circulates treated water to the buildings that comprise the heating load.

The first configuration featured downhole heat exchangers which consist of a pipe loop installed within the bore of a geothermal well. Fluid used in the building heating systems is circulated in the pipe loop and is heated by the geothermal waters in the wellbore. The well may be flowed to provide a constant source of heat; however, disposal of the geothermal effluent is then a problem. Alternately, internal circulation from one formation to another or natural flow in the geothermal reservoir may provide the continued heat supply. In the Glenwood Springs reservoir, such flow is not indicated nor predicted. Further, large downhole exchangers of the size for the calculated load described previously are known to have been successfully operated in only one application, an elementary school in Klamath Falls, Oregon. The possibility of fouling or corrosion of heat exchange surfaces downhole is very real in Glenwood Springs due to the high dissolved solids content of the geothermal waters. Maintenance and reliability of the system are severely impacted under such circumstances. Since the downhole pipe is sized for a specific flowrate, system expansion would require its replacement, and the question of sufficient surface area for high rates of heat transfer becomes important. All the above information supports the decision to eliminate downhole heat exchangers from consideration in this study.

A second option would be to distribute geothermal fluid from the well to each of the buildings to be heated, collect the cooled effluent waters and dispose of them in some manner. Again, a significant problem with the chemical content of the geothermal fluid is anticipated. Studies done at the Geo-Heat Center at the Oregon Institute of Technology have shown that copper tubing used in many types of radiators is particularly susceptible to corrosion from geothermal fluids of relatively low dissolved solids content. Measures would also need to be taken to provide corrosion and scale protection for the distribution piping and pumps. One variation would be to install individual heat exchangers in each building and circulate clean fluid internally; however, each of the small heat exchangers must be inspected and cleaned periodically to maintain design heat transfer coefficients. It seems

inefficient to attempt to deal with the fluid chemistry situation on a building by building basis; therefore, this configuration was rejected for further analysis.

A third configuration has been investigated: use of the geothermal fluid as the supply source for an industrial scale heat pump. The heat pump, manufactured in sizes up to 5 million Btu per hour (1.5 MW thermal) for a single unit, can raise the circulating loop temperature to 180° to 200°F (82° to 93°C), so that minimal retrofit work is required on the existing heating systems. Heat pumps use a relatively small amount of energy to reverse a thermodynamic cycle and move heat from a lower temperature source to a higher temperature source. At an assumed resource temperature of 160°F (71°C), the Coefficient of Performance of the unit is about 5.

The tradeoff evaluated in analysis of the heat pump configuration was the initial investment and additional operating cost of the heat pump versus the cost to retrofit existing buildings with sufficient radiator area to provide the maximum design heat flux on the coldest days. Results showed the heat pump option to be about three times as expensive as the radiator retrofit. Later in the project, conservation measures were determined to be much cheaper than radiator retrofit, making the heat pump configuration look even worse. A significant factor in the heat pump analysis is the mismatch in heat demand and heat output available from the unit: heat demand is at the peak level for only a very small portion of the annual operating period, while the heat pump is ready and willing to supply the high temperatures needed for peak operation for the entire year. This high availability becomes very expensive when not utilized. The point to be stressed here is that the high radiator inlet temperature provided by a heat pump system is not needed for most of the heating season because heat emitter operation at lower temperature is sufficient to meet the reduced system demand. (see section II-D). It may be more reasonable to propose use of a large scale heat pump to provide the peaking heat supply, where radiator inlet

temperature becomes critical to the performance of building heating systems. An analysis of heat pump peaking is presented later in this report.

The most promising design concept was heat exchange between the geothermal brine and closed-loop circulating treat water. By minimizing exposure of the geothermal brine to surface equipment, many advantages are gained. The concept limits concerns with the chemistry of the geothermal fluid to a single component which can be located at the production wellhead and can be selected for ease of cleaning and maintenance. The treated water side can be a closed loop with a minimum concern for corrosion problems. Pump, pipe and heat exchanger materials are less restricted and certainly less expensive. Surface heat exchangers can be piped in parallel to provide for system expansion. A peaking capacity fossil fuel fired boiler can be added to the closed loop without regard for the brine chemistry.

One problem that must be faced is the loss of maximum temperature attainable with a heat exchanger of economic surface area. Proper selection of heat exchange technique can minimize this loss, as will be discussed later. Also of concern with this configuration is the disposal of the geothermal waters after heat exchange. Disposal is a problem with all configurations except a downhole heat exchanger with internal circulation in the wellbore and must be evaluated separately. For design purposes, reinjection of spent brines has been assumed because this option presents the only feasible means of disposal in Glenwood Springs. On balance, wellhead heat exchange with a closed loop water circulation system was chosen because of its simplicity and minimal corrosion impact on the existing buildings' heating systems.

A schematic of the proposed system is presented in Figure 11-2. The concept is simple and employs features which satisfy the concerns expressed in the Design Philosophy. A plate heat exchanger forms the key element of the system, as the site of heat exchange between the

GENERAL SYSTEM SCHEMATIC
FIGURE II - 2

geothermal brine and the treated water in the circulation loop. The fossil fueled boiler provides peaking capacity that varies with demand load; for most of the heating season the boiler is not used. Parallel pumps are used on both sides of the heat exchanger to provide variable flow capacity under partial load. Two of the three pumps operate at peak demand, ensuring a 50% standby capacity in case of pump failure. Details of the system components are discussed later in this section.

System Size Specifications. The geothermal well is a major component of the system, in terms of capital cost as well as its influence on the design of the system. Based on the projected flowrate for the well of 1,000 gallons per minute (3,800 liters per minute), the well will supply energy at a rate far greater than that required for the proposed loop. This fact invites the consideration of expansion capacity to be built into the system from the start, especially in view of the route of the distribution pipeline through the downtown area. Specifications for the three options investigated are presented below:

Option A. System designed to supply only buildings included in this project.

Geothermal Well Flowrate: 250 gpm (950 lpm)

Distribution Loop Maximum Flowrate: 250 gpm (950 lpm)

Temperature Drop in Geothermal Fluid: 20°F (11°C)

Temperature Drop in Distribution Loop: 20°F (11°C)

Portion of System Capacity Supplied by Geothermal Fluid:
2,500,000 Btu/hr (0.8 MW)

Portion of System Capacity Supplied by Peaking Boiler:
2,500,000 Btu/hr (0.8 MW)

Temperature Drop in Distribution Loop (at Peak Demand):
40°F (22°C)

Total System Capacity: 5,000,000 Btu/hr (1.5 MW)

Option B. System designed to supply buildings included in this (Base Case) project and provide 100% expansion capability.

Geothermal Well Flowrate: 500 gpm (1,900 lpm)
Distribution Loop Maximum Flowrate: 500 gpm (1,900 lpm)
Temperature Drop in Geothermal Fluid: 20°F (11°C)
Temperature Drop in Distribution Loop: 20°F (11°C)
Portion of System Capacity Supplied by Geothermal Fluid:
5,000,000 Btu/hr (1.5 MW)
Portion System Capacity Supplied by Peaking Boiler:
5,000,000 Btu/hr (1.5 MW)
Temperature Drop in Distribution Loop (at Peak Demand):
40°F (22°C)
Total System Capacity: 10,000,000 Btu/hr (2.9 MW)

Option C. System designed to supply buildings included in this project and provide 300% expansion capability.

Geothermal Well Flowrate: 1,000 gpm (3,800 lpm)
Distribution Loop Maximum Flowrate: 1,000 gpm (3,800 lpm)
Temperature Drop in Geothermal Fluid: 20°F (11°C)
Temperature Drop in Distribution Loop: 20°F (11°C)
Portion of System Capacity Supplied by Geothermal Fluid:
10,000,000 Btu/hr (2.9 MW)
Portion of System Capacity Supplied by Peaking Boiler:
10,000,000 Btu/hr (2.9 MW)
Temperature Drop in Distribution Loop (at Peak Demand):
40°F (22°C)
Total System Capacity: 20,000,000 Btu/hr (5.9 MW)

The larger system sizes were chosen to match projected well capacity with peak demand load on the system. It seems obvious that a larger system size should provide economies of scale in the cost of system installation and operation as well as hardware. Certainly the cost of drilling and completing production and reinjection wells comprises a significant portion of the total investment. Therefore, it is most reasonable to maximize the production of energy from the well over which spread to amortization of that cost. These suspected economies of scale are found to be well documented in Section III.

Heat Exchanger. A technical evaluation was conducted for two types of heat exchangers as candidates for use in the geothermal system. In addition to low cost, ease of maintenance and expansion capacity were important criteria. A shell and tube heat exchanger consists of a number of parallel tubes installed within a cylindrical shell. One fluid flows through the inside of the tubes and the second fluid flows around the tubes within the shell. Baffles are usually inserted in the shell side flow to provide turbulence and a tortuous path for the shell side fluid. Shell and tube heat exchangers are widely used in the process industry. Plate heat exchangers employ a series of parallel plates which are sandwiched together and manifolded such that the fluids being heated and cooled flow in alternate channels (hot fluid on one side and cold fluid on the other side of each plate). Plate surfaces are commonly embossed with a pattern to cause limited contact area between adjacent plates. This improves the tolerance in plate spacing and excites turbulence in the flow.

For the application under consideration, plate heat exchangers were found to provide much better service than shell and tube units. Plate exchangers produce higher heat transfer coefficients (by a factor of about 3) due to high fluid velocity attained in the relatively narrow flow channels. This high velocity generates high shear forces that enhance heat transfer by reducing the thickness of the laminar sublayer in the boundary layer. The high shear has the added advantage of reducing the rate of plate surface fouling, which is of particular concern with the high Total Dissolved Solids (TDS) content of the geothermal brine in Glenwood Springs.

The improved heat transfer coefficients permit the plate heat exchangers to be constructed with much smaller heat transfer surface area. The units are therefore lighter than shell and tube and, more importantly, cost less. The penalty paid for all this is a greater pressure drop through the plate exchanger, although with proper design, it need not be excessive.

Plate heat exchangers can be designed with approach temperatures as low as 2°F (1°C), although such small values lead to large heat transfer areas and increased cost. Approach temperature is defined as the difference between temperatures of the hot fluid at its inlet to the heat exchanger and the cold fluid after it has passed through the unit. For geothermal applications, this is significant in that performance of building heating systems is a function of the temperature difference between the circulating fluid and room air. Approach temperatures of 2, 4, 7 and 10°F (1, 2, 4 and 6°C) were used in an optimization study for the determination of minimum total cost for retrofit and capital equipment; results are shown and explained in Section IID.

Several manufacturers were questioned to determine the performance of plate heat exchangers under partial load conditions. The data supplied indicates an essentially linear response of heat transfer to decreasing flowrate from the rated maximum. This is important in matching the geothermal heat supply to system demand on the cool days of spring and autumn, when only a fraction of the system capacity is needed.

The method of construction of a plate heat exchanger also presents advantages for use in geothermal systems. The unit consists of a plate frame to which the cold and hot side fluid headers are mounted, a backing plate, with heat transfer plates sandwiched between the two. The stack is held together by a series of compression bolts around the perimeter. This design lends itself quite well to annual disassembly and cleaning to remove any scale deposits that may have formed. It also allows the area of heat exchange surface to be increased simply by the addition of more plates to the stack. An increased heat exchange area can be used to accommodate increased flow or to cause a greater temperature difference (inlet to outlet) to occur in both the hot and cold side fluids at existing flowrates. Such a feature would be significant if the buildings on the system used equipment that utilized more heat from the circulating water, leading to a temperature drop across the

heating equipment larger than the system design value. The plate heat exchanger could then be expanded to accommodate this increased operating temperature difference which would effectively increase the capacity of the system.

It is recommended that the plates be made of titanium, rather than the standard stainless steel. One reason that a manufacturer has suggested this is because of the high content of total dissolved solids (20,000 parts per million) in the Glenwood Springs geothermal brine. Titanium is much more resistant to corrosion under such circumstances and should dramatically increase the reliability of the system. Several other geothermal installations have specified titanium plate heat exchangers, particularly where TDS content of the hot brine was significant. The only drawback to titanium plates is that they are very expensive, about three times the cost of stainless steel. However, at an approach temperature of 10°F (6°C), the heat exchanger cost is still only a minor part of the overall system capital investment. A coupon test of both stainless steel and titanium should be conducted during flow testing of the production well to provide additional data on which to base the choice of heat exchanger materials.

Plate heat exchangers are manufactured by far fewer companies than shell and tube. Several of these have been most helpful in developing data used in this study and are cited in Appendix D. Availability does not appear to be a significant problem at this time. There are operating limits of 300 psig (2 MPa gauge) maximum pressure and 300°F (149°C) maximum temperature on plate exchangers, but the operating conditions for the Glenwood Springs installation would be far below these levels. These limitations apply primarily to the materials used to gasket the plates around the edges; future improvements in the elastomers used for that purpose are expected to result in an improved range of operating conditions for plate heat exchangers.

Since the plate exchangers are built from component parts, it is possible to assemble (from stock frames and plates) units to accommodate almost any specified flowrate, temperature drop and resulting rate

of heat transfer. Thus, units for the proposed system can be specified, assembled and delivered after the temperature and flowrate of the re-source, and consequently system size, are known.

Distribution Pipe. Early in the study of a geothermal system for Glenwood Springs, it was decided that distribution of the geothermal fluid would be impractical because of its relatively high dissolved solids content. Corrosion and deposition in heating equipment in the buildings of the loop is eliminated from concern if a heat exchanger is installed at the wellhead and a secondary circulation loop employed.

In order to find the optimum pipe size, a maximum volumetric flowrate was required. Since the peak heat load of the system was known, flowrate could be found if the temperature drop of the recirculated water in the distribution loop was specified. As part of the Load Analysis, the temperature rise in the distribution loop across the input side was defined to be 40°F (22°C). For the three options under study, flowrates were then known, and the optimum pipe sizes could be determined.

The use of one supply and one return line in the distribution system yields many advantages. By collecting the return water a closed heating loop is formed and treated water may then be used in this loop, which will minimize corrosion. Separate supply and return lines allow for future expansion; whereas if there was a minimum length main line and smaller lines emanating from this main to serve sections of the system then no new users could be connected to the smaller lines operating at full capacity.

Six different types of pipe were evaluated for the hot water supply and return lines: a steel pipe with surrounding urethane insulation, asbestos cement insulated and uninsulated pipe, FRP (fiber reinforced plastic) pipe with urethane foam, carbon steel schedule 40 piping, and bare FRP pipe. Asbestos-cement insulated pipe consists of concentric sections of asbestos-cement pipe with a urethane foam-filled annulus.

An epoxy lining is used to seal the inner pipe. Both the FRP and steel pipes with urethane insulation are wrapped in a plastic jacket which seals the urethane from water absorption and prevents subsequent degradation of the insulating quality of the foam. A wide range of pipe was chosen to represent the available spectrum so that an accurate comparison would lead to optimal pipe selection.

After some initial study several conclusions were made about the course of the pipe analysis. Bare steel schedule 40 piping and uninsulated FRP pipe were eliminated from consideration for the return leg of the loop, since both had a higher cost and higher heat loss than the uninsulated asbestos-concrete pipe. Additionally, steel pipe could have corrosion problems that the non-metallic pipes would not have. It was also decided that the supply leg should be insulated to maintain maximum water inlet temperatures to the buildings. The return leg could be insulated or not depending upon the economic tradeoffs of insulated pipe cost versus the value of lost heat in an uninsulated return.

Heat loss calculations used the method of images. The method of images is a steady heat conduction calculation that assumes an average ground temperature, and solves for pipe heat loss per linear foot. Use of this method put all pipes on the same grounds for comparison of insulation performance. The dollar value of lost heat was based upon heat loss during peaking time periods. Using this basis was most equitable, since the heat supplied at peak demand determines how many users the system could serve. That is, heat loss during non-peak operation has no value since there is no demand for it. Hence, heat loss value was calculated at the price of the peaking heat supply since the peaking system is the source for the incremental heat to replace losses in uninsulated pipe. The peaking system provides about ten percent of the annual system operating output.

The last assumption was that the supply and return lines would be buried in one common trench, the pipes spaced 24" (60 cm) apart. The

pipes would be buried six feet (2 m) deep, with approximately 40% of the pipe below the streets and the remainder being buried in alleys. A length of 4000 feet (1220 m) of supply and 4000 feet (1220 m) of return line was used as the basis of the pipe system. Surface and ground conditions as well as cost estimates for burying pipe were obtained from the city of Glenwood Springs engineering office.

The pump cost and energy consumption was important for considering the overall cost of hot water distribution. The use of pumps operating in parallel was the basis of the design so that part load demand could be matched with a reduced flowrate.

The optimization study examined all major costs of the hot water distribution network. Initial pump cost, electrical power (for pumps) cost, the cost of change in friction loss from one type of pipe to another, heat loss cost, and pipe material cost were evaluated to find minimal system price for the Option A, B, and C systems. The trade-offs of pump size, electrical pumping costs, and cost for larger/smaller pipe to decrease/increase system flow resistance were also evaluated.

Initial pump cost and pump sizing came from distributor's quotes. Electrical power requirements were calculated based on pump motor size and estimated annual running time. Electric power requirements over the system life, like heat loss values, were evaluated in present-worth dollars. The use of present worth analysis permits the valuation of all pump system costs on an equitable basis, and is explained in the economics section. Heat loss cost, as previously stated, is based upon heat loss during peaking and is calculated at the same price as the fuel source for the peaking system.

Asbestos-concrete pipe was the base to which other pipes were compared for friction losses. Cost of change in friction loss is calculated by the additional pumping power required and the associated

electricity consumed. Material cost for pipes was derived from manufacturer's quotes. Cost to bury the pipe was assumed constant over the pipe diameter range for a given flow rate.

The sum of the above cost components for each flow rate is presented in Table II-4. Results from the optimization study show the importance of considering pumping power cost. Between a half and a third of the total distribution system cost is the pump and electricity costs over the 30 year operating period.

For the Option A System (250 gpm), a six inch (15 cm) FRP pipe with urethane foam insulation or insulated asbestos-cement pipe is the optimal selection. The FRP pipe is slightly more expensive, but is much lighter and comes in longer lengths. These qualities may make the FRP pipe less costly to install. The amount of savings available with FRP pipe, which could influence the pipe selection, should be estimated by an installation contractor. Familiarity with installation procedures for a particular type of pipe will also influence contractor estimates.

For the Option B, or base case, (500 gpm) cost is minimized by using eight inch asbestos-cement pipe. FRP pipe in this case does cost more, but reduced installation cost may make FRP pipe competitive with asbestos-cement pipe. The types of joint used in the two pipe alternatives may also be important in defining installation costs, and should be examined.

With the Option C configuration (1000 gpm), selection of either an eight or ten inch asbestos-cement pipe results in minimum cost. There is only a slight cost differential between the eight and ten inch pipe; detailed engineering analysis should be able to determine the better selection. FRP pipe in this case is costlier, but should be examined further.

These results have been incorporated in the overall economic analysis of the system, and should be used as a first approximation. When

TABLE 11-4

DISTRIBUTION SYSTEM COSTS

Pipe Diameter	Option A (250 gpm)		Option A (250 gpm)		Option A (250 gpm)	
	Total Cost FRP		Total Cost Insulated Steel		Total Cost Asbestos-Cement	
	Option A	Option B	Option A	Option B	Option A	Option B
4 inch	\$182,400	\$161,400	\$185,100	\$159,000	\$182,600	\$158,100
6 inch	144,200	112,400	175,300	123,200	134,200	108,100
8 inch	187,000	135,000	191,400	136,500	167,900	125,600

Option B - Base Case
(500 gpm)

Pipe Diameter	Option B - Base Case (500 gpm)		Option B - Base Case (500 gpm)		Option B - Base Case (500 gpm)	
	Total Cost FRP		Total Cost Insulated Steel		Total Cost Asbestos-Cement	
	Option A	Option B	Option A	Option B	Option A	Option B
6 inch	\$222,600	\$190,500	\$243,700	\$201,600	\$203,900	\$178,900
8 inch	237,500	185,600	242,000	187,600	175,000	149,600
10 inch	279,800	205,300	283,800	206,800	201,600	159,100

Option C
(1000 gpm)

Pipe Diameter	Option C (1000 gpm)		Option C (1000 gpm)		Option C (1000 gpm)	
	Total Cost FRP		Total Cost Insulated Steel		Total Cost Asbestos-Cement	
	Option A	Option B	Option A	Option B	Option A	Option B
8 inch	\$310,300	\$258,000	\$314,700	\$260,400	\$291,300	\$249,100
10 inch	339,100	264,100	342,600	265,600	308,800	250,000
12 inch	383,200	284,000	370,100	277,400	340,900	263,000

Option A 8000 feet of insulated pipe (supply and return)
 Option B 4000 feet of insulated pipe (supply) and 4000 feet of
 uninsulated asbestos-cement pipe (return)

more details of the distribution system layout are finalized, then the choice of distribution piping can be made. Such activity would be appropriate in performing the surveying and preparation of layout drawings which are necessary for construction of the proposed system; it is clearly beyond the scope of this study. These initial results show the importance of including electric power cost in the distribution piping optimization, as well as the need for comparing installation cost of FRP and asbestos-cement pipe.

Not included in the cost of the piping is a structure to carry the supply and return lines from the production well/heat exchanger site across the Colorado River to the downtown area where the users are located. According to the City of Glenwood Springs Engineering Office as well as the City Planner's Office, a footbridge has been located in the city development master plan at that site. The footbridge would greatly improve access to the proposed Two Rivers Park (in which the production well is proposed to be located) from the area south of the river where a majority of the city's population lives. It would be a simple task to attach the supply and return lines to the underside of this footbridge. In the event that the footbridge is not built, it is possible to construct a carrier structure across the river; one is already installed upstream to take the water distribution main into the main part of town. Costs for this type of structure would not significantly impact the overall economics of the proposed geothermal system.

Pumps. There are two applications for pumps in the geothermal system as shown in the schematic, Figure 11-2. Pumps are required to move the geothermal brine through the heat exchanger and down the injection well into the disposal formation. The distribution loop also requires pumps to flow the treated circulating water through the heat exchanger, peaking boiler (when operating) and around the estimated 8,000 feet (2,500 m) of distribution pipe back to the pump inlets.

The configuration specified for both sets of pumps is to use three pumps plumbed in parallel. Each pump is sized to handle 50% of the

maximum flowrate for the circuit in which it is installed. This allows one pump to be designated a spare or standby to be used in case of failure of one of the other pumps. System reliability, important in a utility application such as this, is enhanced by this arrangement. In addition, the use of smaller parallel pumps permits the system to be operated at lower total flowrates by running a single pump to match partial load performance with reduced demand, resulting in increased pump life and lower pumping electricity costs.

Performance of parallel pumps can be predicted by constructing system pump curves from data on the individual pumps. This curve is established by taking the single pump performance curve as published by the manufacturer, determining the flow for a given head loss and multiplying this flow by the number of pumps operating in parallel.

Figure 11-3 presents a typical pump performance curve for the distribution loop, with the power requirements for 6" (15 cm) and 8" (20 cm) diameter distribution lines also plotted. Similar curves were used to determine pump sizes for the several system options under study.

Several assumptions were made in the development of pump specifications for the proposed geothermal heating system. Perhaps the most important was that of artesian flow in the production well, so that no downhole shaft pumps were required. All pumps were assumed to be centrifugal type located at ground level. For purposes of calculating maintenance and capital equipment replacement costs, the pumps were assumed to undergo an annual inspection and maintenance to repack the bearings. Circulation pumps were assigned a 15 year lifetime and reinjection pumps, a 10 year service life.

Pump heads required for the two applications were calculated based on maximum flowrate and specified pipe diameters. Pump capital costs as well as pumping energy costs were taken into account in an optimization scheme to minimize the life cycle cost in the distribution loop as discussed in the piping section of this report. Therefore,

Figure 11-3. Typical Pump Performance Curve for Distribution Loop.

optimum pipe diameters were matched to each of the system options studied. An additional pressure drop of 20% was included for pipe valves and fittings. Pressure drops through the various heat exchanger models were given by the manufacturers with a maximum level of about 20 psi (138 kPa). The total discharge head on the distribution loop was then found to be 185 feet (56 meters). Each building on the distribution loop was assumed to have its own internal circulation pump to supply fluid to the heat emitters that meet building heat demand, which relieves the circulation pumps of this burden.

For the geothermal brine side of the system, a required reinjection head of 100 psig (690 kPa) was assumed. Based on the known geology, this value is thought to be somewhat conservative; however, it presented a satisfactory compromise between the minimum and maximum reinjection pressures known to be used in the industry. Total assumed discharge head in the geothermal brine side of the system was 290 feet (88 meters). Pressure on the pump inlet side to meet net positive suction head (NPSH) requirements is presumed adequate, since the noted values were quite low and had no impact on pump design. Specifications for the pumps are given in Table 11-5.

Choice of materials for the pumps is dictated by the type of service encountered. For the reinjection pumps, which will flow the high TDS geothermal brine, stainless steel casing and impeller are required. The distribution loop circulating pumps see only clean, treated water so that bronze or ductile iron are adequate materials of construction. It is noted that because of its role as a key pump component, it may be advantageous to specify the impeller in the circulation pumps be made of stainless steel, at a minimal impact (about 3%) to pump cost.

Peaking Subsystem Design. A system to utilize geothermal heat is highly capital-intensive. The well and surface equipment represent a large investment to tap the resource. Of course, once completed, the

TABLE II-5
SYSTEM PUMP SPECIFICATIONS

<u>System Option</u>	<u>Application</u>	<u>Individual Pump Flowrate gpm (lpm)</u>	<u>Total Discharge Head (ft of water)</u>	<u>Motor Power</u>	<u>Material</u>
A (250 gpm)	Circulation	125 gpm (475 lpm)	185 (56 meters)	10 HP (7.5 kw)	Ductile iron casing, stainless steel impeller <u>OR</u> bronze throughout
B (500 gpm) Base Case	Circulation	250 gpm (950 lpm)	185	20 HP (15 kw)	
C (1000 gpm)	Circulation	500 gpm (1900 lpm)	185	40 HP (30 kw)	
A (250 gpm)	Reinjection	125 gpm (475 lpm)	290 (88 meters)	20 HP (15 kw)	316 stainless steel throughout
B (500 gpm) Base Case	Reinjection	250 gpm (950 lpm)	290	30 HP (22 kw)	
C (1000 gpm)	Reinjection	500 gpm (1900 lpm)	290	50 HP (37 kw)	

actual cost to pump the hot brine through the heat exchange process is minimal. Therefore, if more energy is produced from a geothermal well in a given time period, the cost of each unit of energy is lower, because the significant capital investment can be amortized over the greater production. All this implies that a geothermal direct heat utilization system should be run as close to maximum capacity as possible at all times; that is, it should be "base loaded".

On the other hand, heating of buildings is a cyclic phenomenon, both on a daily and annual basis. The typical building heating system operates only intermittently through most of the year and may be shut off completely in the summer. In a compromise between this varying load and the need to maximize the geothermal system utilization, the proposed system has been designed to base load the geothermal well and provide peaking via an alternate fuel. The base loading is done by specifying a 20°F (11°C) temperature rise from the geothermal heat exchanger at all times during operation of the distribution loop. When the ambient temperature is below 30°F or -1°C, additional temperature rise in the distribution loop is provided by the peaking heat source, to a maximum total of 40°F (22°C). Thus at peak demand (-5°F or -21°C design temperature) one half of the total heat supply rate is provided by geothermal, and the other half by a peaking system. On an annual basis, as explained earlier, the geothermal portion of the system provides about 90% of the required energy.

Two separate types of equipment have been evaluated for use as the peaking heat source in the proposed system. The first was a conventional, fossil fuel fired boiler; two different fuels were considered for such a unit, propane and natural gas. The second candidate was an industrial scale heat pump, which would use as a heat source the geothermal brine from the outlet of the heat exchanger.

Package boilers in the sizes of interest for the various options under study are readily available from a number of manufacturers. Propane was considered as the primary fuel choice because of expected demand

charges and interruptability problems with natural gas; however, after discussions with the local gas utility it appears that natural gas is available in Glenwood Springs, and indeed is the fuel of choice for the peaking boiler. Optimization of the peaking system to minimize total operating cost has included both fuels.

The industrial scale heat pump peaking system was somewhat more complex than the boiler alternative. Because of the salinity of the resource (20,000 ppm), the manufacturer recommended use of an intermediate heat exchanger so that clean, treated water could be circulated in the heat pump evaporator. Even so, the Coefficient of Performance for the unit was approximately 5 for the range of temperatures predicted for the system. This high COP indicates that for every kilowatt of electrical input to the unit, 5 kilowatts of heat are added to the system; obviously, this provides a most efficient use of input energy.

Evaluation of the relative merit of the alternatives consisted of an estimation of the present worth of operation over the projected 30 year life of the system, a so called "life cycle" cost estimate. Included in the total were purchase cost and installation of all equipment associated with the peaking subsystem as well as fuel and electricity costs throughout the operational lifetime. For the heat pump alternative, an additional heat exchanger and associated circulation pumps were added to the cost of the basic unit, as was the present worth of the pumping power. Of course, the prime "fuel" for the heat pump is electricity.

Fuel costs were calculated in present worth dollars that take into account a real cost increase in energy, which varies over the 30 year period by a formula presented in Section III, the economics studies. It should be noted that these predicted energy cost escalation rates are just that - predictions. They represent a "best guess" by authorities with considerable knowledge and experience. However, anyone who has lived through the past seven years in the United States knows that

energy cost increases have hardly been predictable. One can also easily realize that with increasing worldwide demand and limited supplies, the long term trend must be toward a rise in the real cost of energy from all sources. Therefore the relative merit of the peaking alternatives should rest on a reasonably sound basis, although the absolute value in dollars and cents may be somewhat suspect.

Results from the present worth analysis are presented in Table 11-6. For all options, the natural gas fired boiler peaking is the most economical. There are several aspects of the summary table that are noteworthy. The heat pump subsystem requires a capital investment in equipment of about 5 times that needed for the boilers. This would imply that the heat pump would be less sensitive to variations in energy costs. On the other hand, the heat pump is a more complex system mechanically, and may be more susceptible to failure. This is particularly true for application in a peaking mode where the annual use is quite low. A large portion of the cost of electricity for the heat pump is due to demand charge because of the significant current draw of the compressor. While the peaking capacity is needed only 5 or 6 months a year, the demand charge is a year-round assessment. This is only logical since electricity can't be stored and generating capacity must be available for peak operating loads on the electricity distribution grid. Heat pump peaking was attractive from the point of view that it increased the utilization of the geothermal resource by increasing the temperature drop in the geothermal fluid.

Boiler systems have an advantage of much lower initial investment, and would therefore help lower the debt service component of system costs in the early years. This has the effect of making the geothermal energy alternative more competitive with available fossil fuels in the near term. In the long term, peaking with natural gas will present incremental costs for peak energy no greater than the non-geothermal alternative, since natural gas is expected to be the fuel of lowest cost. Boiler systems are also more reliable and require relatively little maintenance.

TABLE II - 6

PEAKING SUBSYSTEM COST

<u>Peaking System</u>	<u>Option A (250 gpm)</u>	<u>Option B (500 gpm)</u>	<u>Option C (1000 gpm)</u>
Heat Pump			
Hardware	\$ 70,500	\$126,300	\$250,900
Electricity	<u>200,000</u>	<u>279,200</u>	<u>423,200</u>
Total	\$270,500	\$405,500	\$674,100
Boiler-Propane			
Hardware	\$ 15,000	\$ 23,500	\$ 48,000
Fuel	<u>250,300</u>	<u>501,500</u>	<u>1,000,000</u>
Total	\$265,300	\$525,000	\$1,048,100
Boiler-Natural Gas			
Hardware	\$ 17,000	\$ 27,000	\$ 53,000
Fuel	<u>137,300</u>	<u>273,000</u>	<u>544,500</u>
Total	\$154,300	\$300,000	\$597,500

Well Design. Two wells will be drilled at Glenwood Springs so as to efficiently produce and dispose of low-temperature (150°F) (65.5°C) geothermal fluids. A large-bore (9-5/8") (24.5 cm) exploration/production well numbered GS 9-1 will be drilled and tested first, followed by a slim-hole (4-1/2") (11.43 cm) reinjection well numbered GS 9-2R.

The geothermal exploration/production well, GS 9-1, will have a cased production diameter of 9-5/8". The primary reason for a large-bore is to allow the natural artesian flow of geothermal fluids to be produced at 1,000 gpm without impedance from a restrictive wellbore. In order to obtain a production casing of 9-5/8", the well must be drilled in progressively smaller stages. First, a 26" (66 cm) bore will be drilled through the gravels and alluvium and 20" (50.8 cm) casing (Grade F-25, Weight 90 pounds/foot) cemented in place with redi-mix. This casing is to prevent boulders from falling downhole during continued drilling operations. Then a 17-1/2" (44.5 cm) bore will be drilled to a depth immediately above potential water production (hot or cold). This bore will be cased with 13-3/8" (33.9 cm) casing (Grade F-25, Weight 48 pounds/foot). This string of pipe is called surface casing and is used to control and prevent blowouts as drilling continues. Blowout preventers and valves can be bolted to the 13-3/8" casing and in the event of encountering large flow rates during continued drilling, the well can be shut in and controlled. Next, a 12-1/4" (31.1 cm) bore will be drilled to the top of the production zone and cased with 9-5/8" casing (Grade H-40, Weight 32.3 pounds/foot). Both casings are cemented with Class "G" cement plus 2% CaCl. The purpose of Class "G" cement is two-fold: (1) it is a more heat resistant cement which will not break down due to heating and cooling and (2) it is very resistant to external ground water corrosion and deterioration. The purpose of a 2% CaCl additive is to accelerate the cement curing time. Finally, an 8-3/4" bore will be drilled through the production zone and be completed as open hole due to the competency of the Leadville Limestone.

The completed wellhead assembly for the geothermal production well GS 9-1 will be constructed of off-the-shelf hardware. Threaded into

the top collar of the 9-5/8" production casing will be a 9-5/8" to 10" swedge which adapts all fittings to a standard 10" (24.5 cm) diameter. Threaded onto the top of the swedge is a 10" casinghead flange. Bolted to the casinghead flange is a 10" master valve. Due to the scaling nature of the geothermal brines at Glenwood Springs, it is recommended that the master valve be a "W.K.M. fullbore-expansion-power seal" gate valve. Though these valves are more expensive than standard "slab-gate" valves, they are designed so there are no internal impedances within the valve to create turbulent flow which eventually leads to scaling. This valve seals itself open to create a smooth interior bore very similar to piping or casing.

Above the master valve is bolted a 10" wellhead "T" which serves a three-fold purpose: (1) to turn produced geothermal fluids into a pipeline, (2) adapt the 10" wellhead down to a 6" (15.2 cm), 8" (20.3 cm) or 10" pipeline size and (3) the "T" allows for eventual entry into the well (via a lubricator system) for logging probes. Bolted to the wellhead "T" is the pipeline.

It is not recommended that flow rates in the pipeline be controlled by throttling back the master valve. This will create impedance within the valve and eventually lead to scaling. Rather, it is suggested the production rates be throttled via regulator orifice plates which can be interchangeable within the pipeline.

The reinjection well is designed very similar to the production well with the two major differences being a smaller bore size and different completion techniques in the reinjection zone. The diameter of the production casing in the reinjection well, GS 9-2R, is 4-1/2". The primary reason for a smaller reinjection well is cost. By drilling smaller bores, the drilling time is measurably decreased, thereby reducing costs. The reinjection well will dispose geothermal fluids into a different zone than from whence they were produced and, therefore, the reinjection well will not have the benefit of natural convective heat

flow. It is anticipated that pumping will be required to force spent geothermal fluids into the disposal zone so a larger reinjection well is not needed initially. By decreasing costs on the initial reinjection well, risk is also decreased. After conducting long-term reinjection testing on GS 9-2R, it will be determined whether the disposal aquifer can indeed handle reinjection rates up to 1,000 gpm. As the heating system expands, additional reinjection facilities may be needed.

Well design, drilling, completion and cementing for the reinjection well is identical to that of GS 9-1 except through the disposal zone. Rather than an open hole completion, as in GS 9-1, the reinjection well will run slotted casing through the bottom 100 feet of the disposal zone. This completion design has a two-fold purpose: (1) to keep the sandstone in the disposal zone from sluffing into the well bore and (2) to prevent the well completion design from having a telescoping effect as would occur if a slotted liner were hung through the disposal zone. A slotted liner would create a restriction in the well bore and thusly increase reinjection pressures, demanding greater pumping capacity.

To prevent contamination of the disposal zone during cementing of the production casing, a "DV tool" (differential valve packer collar) will be threaded into the casing string immediately above the slotted casing. The DV tool plugs shut the casing and wellbore annulus immediately above the disposal zone and do not allow cement to penetrate below the tool. As cement is pumped down the casing, it encounters the DV tool and is channeled back up the annulus between the casing and the borehole wall. After the cement cures it is drilled out, as is the DV tool, and a full-bore channel exists to the slotted casing.

The wellhead completion of GS 9-2R is the same as that described for GS 9-1. All fitting sizes for flanges and valves are adapted to 6" (from 4-1/2" casing) rather than the 10" sizes for GS 9-1. Regulator orifice plates are not needed because reinjection rates can be controlled by pump speeds rather than being throttled by orifice plates.

System Operation. There are two different modes under which the geothermal system will operate - one where the geothermal brine supplies sufficient heat to meet the demand, and the other where additional energy from the fossil-fueled boiler is required. In all operational situations, flowrates on both sides of the plate heat exchanger will be equivalent so that the temperature change in both fluids will be identical.

At ambient temperatures above 30°F (-1°C) the geothermal heat source will supply sufficient energy to meet system demand. Under this part load condition, the temperature change across the heat exchanger for both the geothermal brine and circulation water will be maintained at 20°F (11°C). Variations in demand will be accommodated by a change in the flowrate, which is facilitated by the specification of multiple pumps installed in parallel. Total energy carried in the distribution system is computed by multiplying mass flowrate times the temperature change at the supply end of the loop times the specific heat of the flowing fluid (treated water). When the ambient temperature drops to 30°F, the geothermal heat exchanger is operating at its full rated capacity, and flowrate in the distribution loop will also be at design maximum, with two pumps running under full load.

For weather where the ambient temperature has dropped below the 30°F (-1°C) geothermal design point, the geothermal heat exchanger continues to operate at full rate, and the peaking boiler begins to supply the additional energy by raising the temperature in the circulated water above the heat exchanged output value. This is a most logical approach to take in supplying peaking capacity since at lower ambient temperatures, system demand rises and radiator performance (rate of heat delivery) becomes a significant factor in system operation. As noted in the following section, radiator performance is a function of the mean radiator temperature. If the peaking system provides additional energy via a rise in the temperature of the circulating water, the radiator output is improved at a time when needed the most. At peak demand

(ambient temperature of -5°F or -21°C) the peaking boiler is providing an additional 20°F (11°C) temperature rise in the circulating water so that the total temperature rise at the supply end of the distribution loop is 40°F (22°C). Under such conditions, the rate of heat supply by the system is split evenly between the geothermal heat exchanger and fossil fueled boiler. However, since peak demand days occur only seldom on a yearly basis, the geothermal contribution to the total annual heat supplied by the system is about 90%.

Total dissolved solids content of the geothermal brine in Glenwood Springs is relatively high for a low temperature resource, about 20,000 parts per million. There is concern over the possible deposition of solids in the well casing, surface piping, pumps, and heat exchanger. Based on existing analyses of the various springs in the Glenwood Springs area (Attachment II of Appendix A), sulfide and silica scaling are considered possible and calcite/travertine deposition definite, if mitigation measures are not taken. Carbon dioxide maintained in solution in the reservoir holds the key to preventing calcite/travertine scale formation. The CO_2 acts as a buffer while in solution, but when it nucleates as a gas, the pH of the liquid shifts and the dissolved calcite may be pushed into supersaturation. Therefore by keeping the CO_2 in solution, calcite/travertine scale formation can be controlled.

If the geothermal brine is exposed to the atmosphere, CO_2 will come out of solution unless the partial pressure of CO_2 in air is higher than that required to balance the dissolved species. From the limited amount of data available, it appears that a considerable pressure (about 90 atmospheres) would be needed to fulfill the above condition. A second method of maintaining the CO_2 in solution is to prevent exposure to air under steady-state operating conditions. This is possible if the flow from the production well through the heat exchanger and injection pumps is pressurized and maintained as 100% liquid. Calculations have shown that if absolute pressure at the pump inlet is maintained above 15 psia (1 atmosphere) CO_2 will be maintained in solution in an all-liquid

system. Of course at system start-up and following annual maintenance there is a short time during which air will be present in the system components; it is not felt that appreciable calcite buildup can occur during this transient condition.

Potential for silica and sulfide scaling can be controlled by acidification of the brine at the production wellhead, if significant surface equipment scaling is expected. If only scale in the slotted liner of the reinjection well is of concern, the addition of acid may be made at the reinjection well. The important point to be stressed here is that a detailed scale mitigation strategy cannot be developed until an exploration well is drilled and the chemistry (TDS and dissolved gas content) of the produced brine is known. Calcite scale may be easily controlled via minimized exposure of the produced brine to the atmosphere and there are fairly simple and inexpensive methods that can be applied to the silica and sulfide problem as well.

D. Heating System Performance and Retrofit Design

Standard design practice for hot water heating systems is to assume a water temperature of 180°F (82°C) at the entrance to a radiator and to size the unit to cause a 20°F (11°C) temperature drop in the circulating water from inlet to outlet. This is done by adjusting the exterior (air-side) area of the radiator for a given rate of water circulation in the system. One can affect the temperature drop on the liquid side by changing the flowrate or by changing the exterior area of the radiator. Buildings included in the study were found to have boiler temperature settings of from 170°F (77°C) to as high as 220°F (104°C). The weighted average of 210°F (99°C) was used in the calculation of performance for existing systems.

For conventional hot water heating systems, the limiting (smaller) heat transfer coefficient is on the air side of the heat emitter. This means that the surface area, temperature difference (radiator to room

air), or both must be larger than the water side values in order to match the heat transfer from the interior to the exterior of the unit. The implication here is that the reduced water temperature expected during geothermal operation will cause a decrease in the "radiator to room air" temperature difference, and a corresponding reduction in the output of heating systems in existing buildings.

Performance of radiators at reduced water inlet temperatures is shown in Figure 11-4. The output is compared to that of a unit operating at the design conditions noted above. The circled operation point is the base case assumption for operation of only the geothermal heat exchanger; the squared point presents radiator output when the peaking subsystem is added to the geothermal. The data shown in the graph was calculated by assuming fixed area for the heat emitter and that liquid flowrate was adjusted to attain the water temperature differences shown. The most important result is to note that the output of existing radiators and fan-coil units designed for use at temperatures of 180° to 220°F (82° to 104°C) will be reduced when switched to geothermal use.

This reduced performance only has significant impact over that small portion of annual operation during which the outside temperature is well below freezing. This is illustrated in Figure 11-5, a Comparison of Geothermal Radiator Performance and Heat Demand as a Function of Ambient Temperature. At load levels less than one-half of maximum, the entire demand is supplied by the geothermal heat exchanger, and the existing radiators can supply heat at an adequate rate to maintain interior building temperatures. When the geothermal heat exchanger is running at 100% of capacity, the system demand is one-half of the peak level, and radiator performance is at 63% of design output for the 130°F (54°C) return water temperature case, more than adequate. Thus only intermittent circulation of geothermally heated water is needed to meet the demand for heat. However, as the peaking system is required to supply additional demand, the performance curve drops below the demand curve and the existing radiator area will not transfer sufficient heat

AIR-SIDE RADIATOR PERFORMANCE AT REDUCED WATER INLET TEMPERATURES.

FIGURE II - 4

COMPARISON OF GEOTHERMAL RADIATOR PERFORMANCE AND HEAT DEMAND AS A FUNCTION OF AMBIENT TEMPERATURE.

FIGURE II - 5

to maintain room temperature, even though inlet temperature is raised by the fossil fueled peaking unit. At peak demand, the 130°F (54°C) return case radiator (which corresponds to a 150°F [66°C] geothermal heat exchanger outlet temperature on the closed-loop side) will supply only 76% of the demand; or viewed in an alternate context, 32% additional radiator area is required to supply the peak load under the stated conditions. This short fall of supply as compared to demand must be addressed to complete the design of the geothermal system.

There are three alternative means to satisfy the difference between supply at geothermal system operating conditions and peak demand. Each has advantages, and the ultimate solution to the problem may well involve some combination of all three. The first is to simply rely on overdesign of the original heating system. Standard practice has been to calculate the heat loss from a building or room, add 10%, and choose the next larger unit from a manufacturer's catalog. Thus many existing systems have capacity in excess of peak demand at design conditions, which may be sufficient to permit operation at geothermal temperatures to meet the peak load. A simple test of this excess capacity factor is to lower the operating temperature on the present boiler on a day when peak demand is expected. If the system performs satisfactorily, the temperature can be lowered even further until the demand is not met. The reduced temperature at which the existing boiler meets the peak demand may be at or below the conditions at which the geothermal system is predicted to operate. In any case, it is most likely that some excess capacity exists in the system which can reduce the required retrofit in the other categories. This reliance on overdesign to meet all or part of the shortfall during geothermal is easy to quantify and best of all, is basically free.

The second alternative solution to the radiator performance question is to install additional radiator surface where needed to increase heat supply rate to meet peak demand. The obvious disadvantage of this method is that of cost; the new equipment, piping modifications and

installation labor can add up to a significant investment. On the other hand, if such work is necessary it may provide an opportunity to replace an old or failing heating system, to improve the temperature control on an individual office or floor basis, or to install units capable of cooling during the summer months. This option should be considered carefully, so that costs and advantages are weighed against each other. It should be recognized that if an aging system is replaced so that geothermal energy can be used, the entire cost should not be included in determining the feasibility of the geothermal system. Rather, an allowance should be made for replacement costs that would be incurred no matter what the source of heat in the building.

The final means to close the gap between heating system performance and peak building demand is simply to reduce the demand to a level where existing equipment operating at geothermal temperatures is adequate. Over the past several years, conservation of energy in buildings has been the subject of intense study and analysis. In a world of swiftly rising energy prices, simple conservation measures have become quite cost effective, often paying for themselves in energy savings in just a few years. Reduction in peak demand via the judicious use of conservation can be an effective way to match performance of the geothermal heating system and building demand.

Inquiries have revealed that almost no measures have been taken to date to reduce energy consumption in the buildings included in this study. Thus, the installation of energy saving equipment and materials could indeed lower demand. An energy audit was recently performed on one of the older public buildings in Glenwood Springs. By assuming that the recommended conservation steps for that site are typical of the savings that could be realized in the study buildings, estimates were made of the cost to install conservation modifications to the buildings with reduced geothermal heating system performance. Since the heating system output is a function of the temperature of the geothermal resource, the cost of these conservation measures also varies with resource temperature; however, the calculations showed that conservation

retrofit was less than 1/3 the cost of the installation of additional radiator surface for all temperatures considered. A most important note in consideration of the conservation alternative is that through energy savings over the life of the building the modifications will pay for themselves and therefore the initial investment need not be charged against the cost of a geothermal system in determining its economic feasibility. This is where the true impact of conservation is realized.

For certain buildings, replacement of existing heating systems will be mandatory, because they are not adaptable to the use of hot water. Examples of such systems are gas-fired, forced air furnaces and gas-fired unit heaters. The Garfield County Jail uses several forced-air furnaces, while both the City Hall and Sewage Treatment Plant employ unit heaters in portions of the structures. These units would require replacement with properly-sized water coil unit heaters. In addition, the administrative area of the Sewage Treatment Plant is heated by electric baseboard units. Water-fed fan convectors could be used to replace them. It was also assumed that installation of water coil unit heaters in the city maintenance facility would be more appropriate and would provide greater comfort than the existing radiators. Cost estimates for the above-described mandatory retrofit was made, with an assumption of installation costs (labor and materials) of 2.8 times the capital cost of equipment.

Estimates for retrofit of additional radiator area sufficient to meet demand at the lower geothermal temperatures were made. These calculations assumed that the additional capacity was the only means of making up the gap between supply and peak demand, and used the more appropriate fan convector units. Again, installation was computed at 2.8 times capital costs. These projected costs were then compared to the estimated cost of conservation retrofit.

Since all the retrofit costs noted above are functions of the temperature obtained from the geothermal system, an optimization was undertaken to define the "approach temperature" for the plate heat exchanger

which resulted in minimum system cost. The approach temperature is defined as the temperature difference between the hot side inlet and cool side outlet to the heat exchanger. It is a measure of how closely the clean water in the distribution loop approaches the temperature of the geothermal brine at the wellhead. Of course to promote the heat transfer necessary to minimize the approach temperature requires a significant increase in surface area and thus cost of the heat exchanger. The tradeoff to be evaluated is therefore defined: the increased cost of the heat exchanger at smaller approach temperatures versus the reduced cost of mandatory and conservation retrofit at the higher system operating temperature generated by the smaller approach temperature.

Tabulated results of the optimization are presented in Table II-7. For temperatures of 150°F (66°C) and greater, the 10°F (6°C) approach heat exchanger resulted in minimum total expenditures. Only at the lowest predicted reservoir temperature of 140°F (60°C) did a reduced approach temperature of 7°F (4°C) provide minimum total cost. The estimates of radiator retrofit are provided for comparison purposes only. These costs are for the Option B system, which would include 100% expansion capacity while serving the buildings in the study. If the conservation alternative were chosen to solve the heating system performance problem, it is estimated that an additional 20% of system capacity from the reduced demand in buildings where conservation measures are implemented, would become available to satisfy expansion demand. It should also be noted that the results in Table II-7 incorporate costs for titanium plate heat exchangers. If stainless steel is used for the heat exchanger material, the optimum may well shift toward lower values of approach temperature.

E. System Capital Cost Summary

The following list of material, labor, and other associated costs covers the projected expenditures for construction of the proposed project. Descriptions of the cost assumptions and sources for summary figures are given here, and Table II-8 lists the estimated prices.

TABLE 11-7

Retrofit Cost Optimization
Option B (500 gpm)

<u>Well Temperature</u>	<u>Heat Exchanger Approach Temperature</u>	<u>Heat Exchanger Cost</u>	<u>Cost of Radiator Retrofit</u>	<u>Cost of Conservation Retrofit</u>	<u>Cost of Mandatory Retrofit</u>	<u>Total for Heat Exchanger, Mandatory and Conservation Retrofit</u>
140°F (60°C)	2°F (1°C)	\$91,100	\$375,600	\$105,500	\$42,200	\$238,800
	4 (2°C)	43,800	393,400	116,500	43,200	203,500
	7 (4°C)	25,500	420,100	133,200	44,200	202,900
	10 (6°C)	15,800	446,800	149,800	45,700	211,300
150°F (66°C)	2°F	\$91,100	\$293,500	\$79,000	\$38,800	\$208,900
	4	43,800	309,600	82,900	39,300	166,000
	7	25,500	333,700	88,600	40,400	154,500
	10	15,800	357,800	94,400	41,400	151,600
160°F (71°C)	2°F	\$91,100	\$222,400	\$60,200	\$35,800	\$187,100
	4	43,800	236,100	63,900	36,400	144,100
	7	25,500	256,800	69,600	37,100	132,200
	10	15,800	277,400	75,200	38,200	129,200
170°F (77°C)	2°F	\$91,100	\$142,900	\$42,800	\$33,300	\$167,200
	4	43,800	159,300	46,200	33,900	123,900
	7	25,500	184,000	51,400	35,100	112,000
	10	15,800	208,600	56,500	35,400	107,700
180°F (82°C)	2°F	\$91,100	\$101,000	\$28,300	\$31,200	\$150,600
	4	43,800	107,400	31,100	31,500	106,400
	7	25,500	116,900	35,200	32,200	92,900
	10	15,800	126,500	39,300	32,800	87,900

TABLE 11-8
CAPITAL COST
SUMMARY FOR PROPOSED SYSTEM OPTIONS

<u>Description of Cost</u>	<u>Option A (250 gpm system)</u>	<u>Option B (500 gpm system)</u>	<u>Option C (1000 gpm system)</u>	<u>Certainty in Cost Estimate*</u>
Well Site Selection	\$ 50,000	\$ 50,000	\$ 50,000	3
Well Drilling	268,068	268,068	268,068	3.5
Circulation Pumps	5,400	8,800	15,800	4
Injection Pumps	7,713	9,078	14,181	4
Titanium Heat Exchanger	9,500	15,800	31,600	4
Pump & Heat Exchanger Installation	29,610	54,328	90,300	3
Heat Exchanger Building	10,000	10,000	10,000	3.5
Pipe Cost	54,760	81,520	113,640	4
Pipe Fittings	5,476	8,152	11,364	3.5
Pipe Installation	32,200	32,200	32,200	3
Expansion Tank	5,000	5,000	5,000	4
Peaking System (Hardware Installed)	17,000	27,000	53,000	4
Mandatory Retrofit	19,100	38,200	76,400	3
Discretionary Retrofit	75,200	150,400	300,800	3
Control System	25,000	25,000	25,000	4
Engineering Cost	50,000	58,000	70,600	
Contingency	55,000	64,000	77,600	
Present Value of Equip- ment Reconditioning and Replacement over Life of System	17,188	26,518	47,827	4

*Rating is on a scale of 1 to 5, with 5 = highest confidence in cost estimate, 4 = a distributor's/manufacturer's quote, 3 = best estimate, 2 = price is uncertain, 1 = price is a random number.

Well site selection cost included funding for three additional tests: detailed gravity measurements, shallow heat flow/stratigraphic wells, and magnetotelluric/Schlumberger electrical resistivity depth soundings. These tests are deemed important in the selection of the drill site, and are described in greater detail in the geology section. Well drilling cost for both a production and injection well include the costs of drilling equipment rental, well casing, cement for the casing well head hardware, site preparation and clean up for drilling, and the labor costs of drilling. The figure quoted in Table 11-8 includes a twenty five percent contingency on the total well costs.

Cost for the three pumps for circulating the district heating water were derived from distributors quotes, and reflect proper materials and adequate pumping power for the three system options. The three sizes of injection pumps were also priced from distributor's quotes.

Cost quotes for heat exchangers specified for the system options were obtained from several manufacturers. The figures shown in the Table reflect the use of titanium plates to resist corrosion in the high TDS brine of the Glenwood Springs resource. There were conflicting recommendations on the materials question, but the conservative (and more expensive) choice of titanium was used for cost estimates.

Cost to construct a building to house the heat exchanger, pumps, peaking heat source, and control system is estimated at \$10,000. The facility will require a concrete foundation and floor to support the equipment and will be self-heated with radiated geothermal heat in the winter.

The cost of the 8000 feet (2500 m) of hot water distribution pipe is based on an insulated asbestos-cement supply line, and uninsulated asbestos-cement return line, each 4000 ft (1250 m) long. The prices in Table 11-8 came from a manufacturer's quote, and although asbestos-cement pipe is quoted, it is recommended that the use of FRP pipe should

also be considered. It is expected that FRP pipe may cost less than asbestos-cement pipe to install since it comes in much longer lengths (and therefore requires fewer joints) and also weighs considerably less. In addition, with FRP pipe there is slightly less heat loss, and no chance of asbestos contamination of the circulated water. For the cost of pipe alone, FRP is slightly more expensive than asbestos-cement. FRP pipe in large diameters also requires use of a complex process to make up joints.

Pipe fitting costs were estimated to be ten percent of the total cost of pipe materials. Fittings needed include pipe elbows, tee's, and taps to serve the buildings on the district heating system.

Cost of burying the pipe is based upon estimates made by the city of Glenwood Springs engineering office. Pipe would be laid in a trench six feet (2 m) deep by 3 feet (1 m) wide which will handle both supply and return lines. Pipe installation is estimated to cost \$6.75 per linear foot in alleys, and \$10.00 per linear foot in streets. The price difference is due to tamping the backfill under streets, and street removal and repair cost. Of the 4000 feet of the distribution system 40% is estimated to be under streets, and 60% in alleys or unpaved ground.

The cost of an expansion water tank for the closed-loop distribution system is based upon previous reports of geothermal heating systems.

The peaking system cost estimate was based upon a comparison of the present worth value of a fossil fuel boiler burning either propane or natural gas, and an industrial scale heat pump. For all system sizes the cost of a boiler burning natural gas was considerably lower than the other options. Peak system components costs came from distributor's quotes, and fuel costs were calculated from the current rates for natural gas, propane, and electricity.

There are several assumptions that have significantly influenced the development of estimates for the cost of retrofit for the proposed system. Perhaps the most notable of these is the division of retrofit engineering into two categories - systems which must be replaced because they are not designed to use hot water or steam as the working fluid and those which require only minor modification in order to utilize the geothermally heated circulating water. About 1/3 of the total system peak demand in the buildings under study falls into the mandatory retrofit category, consisting of two types: electric baseboard heaters and gas-fired forced air units. In calculating mandatory retrofit costs for the two larger sized options, an assumption that 1/3 of total peak demand falls into this category was carried through.

Retrofit of the remaining systems that can circulate hot water was also studied. The chief concern for these systems is the performance of the heat emitters at the inlet temperature of circulated water to each unit. In all likelihood, this inlet temperature will be lower under geothermal system operation than the temperature available with the present boilers. This reduced performance can result in a shortfall in heat available on peak demand days. One solution to the problem would be to install additional heat emitter surface area to make up the difference. An alternate (and cheaper) approach is to undertake conservation measures to reduce the peak demand, as described earlier. Since the cost of conservation retrofit can be justified in terms of net heat savings, there is no cost to be carried into the calculations for unit cost of geothermal heat. An estimate of the overall conservation cost is noted in Table II-8, and has been based on an energy audit of a typical public building.

In preparing the above-mentioned estimates, a resource temperature of 160°F (71°C) has been assumed. The mandatory retrofit-costs are a weak function of resource temperature over the range predicted for the Glenwood Springs reservoir. A final assumption made in the preparation of retrofit cost estimates is that installation (labor and materials)

for retrofit hardware would be 2.8 times the equipment cost. The uncertainty of such a figure must be noted, as the ease of installation can only be determined on a detailed building by building basis, which is beyond the scope of this study.

An estimate of control system cost was verified by two manufacturer's representatives as reasonable for control of pumping rates, operation of the peak heating system and temperature monitoring.

Engineering costs are estimated at ten percent of the total system costs (not including conservation retrofit) based upon industrial standards. A contingency of ten percent of the engineering and all other costs is added to the geothermal system price.

A list of service and material supplies for the above mentioned costs is included as Appendix D.

F. Disposal Alternatives

A study has been made of the options for disposal of spent geothermal effluents from the proposed Glenwood Springs District Heating System. Five alternatives have been identified and are evaluated in the following summary. The recommended method is to reinject the brine underground after removal of the economic portion of the heat content via a plate heat exchanger.

Downhole Heat Exchanger. Use of a downhole heat exchanger would permit operation of the system without removal of fluid from the well, or possibly with a "bleed" flow of a few liters per minute. Such a system assumes that sufficient internal circulation is available within the wellbore to facilitate heat transfer at the required rate. For the size of system to be used in Glenwood Springs, only one successful application of the downhole heat exchanger technique is known. There is no particular indication that the Glenwood Springs resource exhibits the

required internal circulation. Of much greater concern is the high dissolved solids content of the geothermal brine, which could promote foaling or corrosion of the downhole heat exchanger surface. For these reasons, the downhole heat exchanger has been designated not feasible for the application under study; this is unfortunate, as downhole heat exchange provides the least costly option in terms of disposal.

Disposal into the Colorado River. If the geothermal fluid is brought to the surface for distribution or heat exchange at the well-head, the spent brine must be disposed of in some manner. One option would be to flow the effluent into the Colorado River, which passes next to the proposed drill site. The Colorado River flows into the Gulf of California, and its waters are heavily used for irrigation and other applications throughout its length. As a consequence, the salinity of the river is quite high by the time the waters reach the US-Mexican border, a matter of concern to both countries. In recent years, measures have been initiated to reduce the dissolved solids content of the Colorado River, so that there are regulations which would prohibit direct disposal of the highly saline (20,000 ppm) geothermal brine into the river. Construction of the smallest system under study would have resulted in the addition of about 5000 tons (2.2×10^7 kg) of dissolved solids to the Colorado River annually, if river disposal was available. The rise in temperature permitted by addition of effluent to waters in Colorado is also regulated by the State Department of Health. A third problem with surface disposal is concern over subsidence of land surrounding the well due to withdrawal of fluids from the reservoir without replacement other than natural recharge. The major natural hot spring in Glenwood Springs, the Yampa, has flowed at 2500 gpm (9500 lpm) for over 100 years with no evidence of subsidence in the area.

River disposal could be considered if the solids content of the geothermal effluent was lowered by chemical treatment. The problem here is that the brine has a chloride content of about 11,000 ppm, which is most easily removed by desalinization, an expensive and cumbersome process. For all of the above reasons, river disposal has been discarded as a viable alternative.

Disposal through the Sewage Treatment Plant. The City of Glenwood Springs has recently completed an expansion of their sewage treatment plant with added capacity and improved process flow. Heat from the geothermal resource is proposed for use in the primary treatment area, which must be maintained above 60°F (16°C) for the biological digesting agent to remain active. A natural extension of using geothermal heat in the treatment plant buildings was a consideration of effluent disposal through the existing sewage treatment system.

Effects of such a plan would be several. For the smallest heating system investigated in this project (at maximum flowrate), an additional 360,000 gallons per day (1.4 million 1/day) of fluid would be processed through the treatment plant. This would not overload the facility at present; however, the ability of the system to handle future increased sewage loads would be significantly reduced.

The dissolved solids content of the geothermal fluid would be diluted by the sewage flow; however, at current process rates, the dilution would be between two and three to one so that the TDS content would remain at several thousand parts per million. This rate exceeds greatly limits placed by the Colorado State Department of Health on the City of Glenwood's treated sewage discharge into the Colorado River.

Heat content of the effluent brine would present both a help and hindrance to the Glenwood Springs sewage treatment system. When warmed, the digestion process in the sewage is accelerated; the rate change is less than 10%. On the other hand, discharge of treated effluent to the river is also temperature limited because of concerns about the effects of high temperatures on the river ecosystem. A more detailed analysis of the effects of brine disposal through the sewage treatment plant is presented in Appendix A. CH2M-Hill, a Denver consulting engineering firm, has assembled a summary report under subcontract to DRI which discusses the interaction of geothermal effluent and sewage treatment and discharge.

Aquaculture Treatment System Disposal. As a complement to the CH 2M-Hill report, an analysis has been made of the effects of disposal of spent geothermal brines on aquaculture sewage treatment systems. These systems utilize aquatic plants and animals to carry out the treatment process in a natural environment. If proper growth conditions can be maintained in the treatment ponds, this approach is less energy intensive than the standard treatment processes now used in most communities. The Applied Aquatics Resources Institute has performed this study and has come to the general conclusion that there may indeed be significant benefits for this process from the heat content of geothermal waters; however dissolved solids content presents a barrier that is difficult to overcome. In particular, the high TDS in Glenwood Springs would make such a system infeasible there. The AARI report is included in this document as Appendix B.

Evaporation Ponds. A fourth disposal method is to flow the spent brine to evaporation ponds where the water content is evaporated and the remaining minerals collected and removed periodically to some suitable site. Since the prospective drill sites in Glenwood Springs are within the city limits, this option is not suitable from a land use point of view. The amount of available land is too small to construct the necessary ponds, which would present a visual eyesore if employed, anyway.

Underground ReInjection. This final alternative appears most feasible for the disposal of spent fluids in Glenwood Springs, for several reasons. The first is that all other alternatives discussed above have been eliminated. More importantly, by reinjecting the fluid, concerns for reservoir depletion and subsidence from fluid withdrawal are abated. The Colorado State Oil and Gas Commission regulates reinjection from the point of view that potable aquifers may not be contaminated with fluids from non-potable aquifers which are being reinjected. ReInjection is therefore best limited to the formation from which the fluid was withdrawn. When fluids are reinjected, their salinity becomes less of a factor, provided that measures can be taken to minimize their impact on heat exchangers and other surface equipment.

The major effect of the choice of reinjection as the means of disposal is in the area of system costs. Drilling of a reinjection well and the purchase and installation of reinjection pumps can approximately equal the cost of the production well, so that there is a significant increase in capital costs. Because of the increased longevity of the resource and other benefits ascribed to reinjection, the additional investment appears justified. In the case of the system under consideration, reinjection seems to be the only viable disposal alternative.

Blank

III. ECONOMIC EVALUATION

An evaluation of economic feasibility was performed for the base case system configuration described in the previous chapter. The sensitivity of the results to a number of key parameters was also examined. Also investigated was the fiscal impact on the City of Glenwood Springs of funding the geothermal system using several different financing methods available to the city. Finally, some aspects of the issue of pricing of geothermal energy were examined.

Economic feasibility is not, by itself, a sufficient reason for any decision-maker, but particularly a governmental entity such as the City of Glenwood Springs, to justify an investment decision. The city should also consider other factors, such as the economic feasibility and political desirability of alternative uses of its financial and managerial resources. However, the analysis described below does indicate that economic considerations do represent an incentive to system implementation.

A. Method of Analysis

Due to the nature of the geothermal heating problem addressed in this study, existing, generalized geothermal system economic evaluation computer programs were not useful. Instead, a levelized cost approach, using 1980 dollars, was used throughout the analysis.

A levelized cost is a single cost value which reflects both the time value of money and cost escalation over the life of a project. This value is comparable between alternative projects. In effect, a levelized cost is the weighted average cost over the duration of the project. The numerator of weighting factor for a given year is the product of the discount factor (which reflects the fact that a dollar a year from now is worth less than a current dollar due to the fact that a current dollar can be invested) and the cost escalation factor for

that year. The denominator of the weighting factor is the sum of the discount factors over the life of the project. Mathematically, a levelized cost can thus be expressed as:

$$LC = \frac{\sum_{n=1}^N (1+r)^{-n} (1+e)^{n-1} C}{\sum_{n=1}^N (1+r)^{-n}}$$

where N = project life

LC = levelized cost

r = discount rate

e = escalation rate

C = initial cost

For a more detailed exposition, see Appendix E of (uhl, 1979). Taylor discusses the incorporation of capital costs in a levelized cost framework in Attachment I, Chapter 10 of (U.S. Department of Energy, 1979).

In this analysis, a total levelized cost, incorporating both capital and operating and maintenance costs, was computed. This cost was compared to the levelized cost of the natural gas which would be displaced by the geothermal system. The present value of system savings (PVSS) was found by computing the present values of the two levelized costs and determining the difference.

The analysis was performed using constant 1980 dollars. This means that the impact on the absolute values of the costs due to the general rate of inflation is neglected. Thus, escalation rates for costs are stated as rates in excess of the rate of general inflation. Similarly, the interest rate charged on capital investments is adjusted for inflation. The result of this assumption is to change the timing of the break even point in the annual cash flow (Table III-4); however, overall economic feasibility of the system is not affected.

The buildings to be served by the geothermal heating system are typically over 50 years old. The existing heating systems are

correspondingly old, but some have been upgraded over the years. Thus, virtually all of the heating systems are candidates for replacement in the relatively near future. However, in calculating the cost of the conventional system, it was assumed conservatively that the existing systems would last another 30 years. Similarly, the non-fuel operating and maintenance costs were neglected. Therefore, only the cost of the natural gas currently used in the existing system was considered in the cost of the conventional system. This assumption biased the analysis against the geothermal system; however, this bias has little or no effect on the outcome of the analysis.

The retrofit costs estimated in the previous chapter included in the system cost only mandatory retrofit investment, i.e., investments required to physically allow the use of a geothermal heating system. For example, natural gas forced air systems must be replaced with radiator systems. Buildings already having hot water or steam heating systems may not require any retrofit investments, if the system is sufficiently oversized that the existing radiator surface area can meet the heat load using geothermal water. Buildings which do require retrofit investments can accomplish the conversion to a geothermal system in one of two ways: increased radiator area or energy conservation actions which lower the heat demand of the building to the point that the existing radiator surface area is sufficient. As was discussed in the previous chapter, conservation was found to be the cheaper of the two methods. However, increasing the radiator area does yield some benefits, such as additional control capabilities or replacement of aged equipment, which argue for such a retrofit method. It is believed that a combination of the two methods will be used in those cases where retrofit is needed at all; thus, only a range of retrofit costs was estimated.

Mandatory retrofit costs are capitalized in this analysis, primarily because the initial user of the system will be the City of Glenwood Springs. Although a case can be made to exclude such costs, the effect

TABLE III-1

RETROFIT COSTS AS A FUNCTION OF RETROFIT METHOD
AND WELLHEAD TEMPERATURE FOR A BASE CASE
(500 gpm) SYSTEM*

<u>Wellhead Temperature, °F</u>	<u>Mandatory Retrofit Cost, \$</u>	<u>Radiator Retrofit Cost, \$</u>	<u>Conservation Retrofit Cost, \$</u>
140	44,200	420,100	133,200
150	41,400	357,800	94,400
160	38,200	277,400	75,200
170	35,400	208,600	56,500
180	32,800	126,500	39,300

*Retrofit costs are directly proportional to system size.

Note: Mandatory retrofit costs are included in the geothermal system cost; radiator and conservation retrofit costs will henceforth be called discretionary retrofit costs.

on the analysis would be negligible since the retrofit costs are a minor contributor to the total capital costs. The retrofit costs included are real and necessary, and must be considered for the determination of overall project economic feasibility. Also included in the capital costs are the discounted costs of equipment replacement and reconditioning over the life of the system.

Table III-1 presents retrofit costs as a function of method and wellhead temperature for a base case 500 gpm (1900 lpm) system. It should be remembered that the estimated system cost includes only mandatory retrofit costs. In the interest of fairness, it is assumed that the owner of each building will pay for that building's additional radiator or conservation retrofit cost. Thus, the present value of the system's energy cost savings must be at least as great as the minimum total discretionary retrofit cost. The minimum total discretionary retrofit cost here is the conservation retrofit cost. As discussed earlier, conservation costs will pay for themselves with gas cost savings and hence could be excluded as a retrofit cost. However, no effort was made to evaluate the cost effectiveness of connection to the geothermal system on a building-by-building basis.

B. Basic Assumptions

Table III-2 presents the primary economic assumptions used in this study. Municipal ownership of the system was assumed for four reasons. First, the city would be a major user of the energy produced. Second, the land on which the production and injection wells will most likely be located is owned by the city. Third, the city already owns the electric power distribution system and the water and sewage system; city ownership of a geothermal heating system would be in keeping with city policy. Finally, and perhaps most importantly, it appears that a privately owned system could be more expensive; DRI has estimated that only 18 person-weeks of effort per year are needed to operate, maintain and administer the 500 gpm system. The system must therefore be a minor interest of

TABLE III-2

BASIC ECONOMIC ASSUMPTIONS

System size = 500 gpm (1900 lpm)/ 18.46×10^9 Btu/yr (1.95×10^{13} joules/yr)

System life = 30 years

Wellhead temperature = 160°F (71°C)

System owned and operated by City of Glenwood Springs

Equity fraction of capital expenditures = 20%

Required real return on investment = 10%

Debt real interest rate = 3%

First year labor cost = \$10/hour

First year electricity cost = \$.04/kwh

First year natural gas cost = \$4.07/mcf (\$5.71/net MM Btu or \$.0195/kwh)

Capital real escalation rate = 0

Labor cost real escalation rate = 0

Electricity cost real escalation rate = 5.5% per year to 1984,
1% per year thereafter

Natural gas cost real escalation rate = 10% per year to 1984,
2% per year thereafter

Insurance cost = \$1.50/\$100 capitalized value

In-lieu-of-taxes charge = 5% of revenues

any private developer, if large, fixed labor and administrative costs are to be avoided. The question of municipal ownership of the system is discussed in more detail in Section V.

City ownership of the utility yields two immediate consequences. Perhaps the most important of these is the fact that the city, as a tax-exempt entity, receives no benefit from the energy investment tax credits granted by Congress in the Crude Oil Windfall Profits Act of 1980 (PL 96-223) and the State of Colorado. However, these credits are usable by private citizens (or firms) if retrofit investments are necessary to join the system.

A second aspect of city ownership is the ability of the city to back construction bonds by the full faith and credit of the city via general obligation bonds. Under certain circumstances, it may be possible for the city to fund the system with little or no equity participation. Revenue bonds may also be used; however, the willingness of the bond market to accept such bonds, under such conditions of risk, is unknown. Financing alternatives are discussed in Section D of this report.

The base case system (500 gpm) is designed to provide 18.46 billion Btu of heat per year. This system is approximately twice as large as is required to meet the needs of the seven public (city, county, federal) buildings in the immediate area. The economic feasibility of smaller (Option A) and larger (Option C) systems is evaluated in Section C of his report.

- Operating costs were estimated by first obtaining current costs and then applying real escalation rates to these costs. Labor costs were estimated by first estimating labor requirements and then assuming that city work crews and office personnel would be responsible for the operation and administration of the system. According to the city engineer, appropriate personnel currently cost the city about \$10 per hour,

including fringe benefits. Wages are assumed to increase at the general rate of inflation; thus, no real increase in labor costs is assumed.

Electric power is primarily used by the circulation and injection pumps in the geothermal system. Electricity consumption was estimated by applying a pump efficiency factor of 75% and a load factor of 50% to those pumps chosen in Section II. After demand charges are taken into account, the current city electric power commercial rate structure yields an approximate rate of \$0.040/kwh, which was then applied to the consumption estimates. Discussions with the Colorado Energy Research Institute (CERI) resulted in an assumption of a real escalation rate of electricity costs of 5.5% per year until 1984 and a 1% per year escalation rate thereafter. It should be noted that these are not "official" CERI estimates; CERI does not provide official estimates.

Natural gas is the primary heating fuel in the large buildings of interest to this study. Natural gas is also the recommended peaking fuel for the geothermal system. Peaking fuel consumption was assumed to be 10% of the annual load. A combustion efficiency of 80% was also assumed. In August 1980, the commercial rate in Glenwood Springs for non-interruptible commercial users approved by the Colorado Public Utilities Commission was \$4.07/mcf (\$.0195 kwh) including the gas price adjustment factor. Discussions with CERI led to an assumption of a real annual increase in the price of natural gas of 10% per year until 1984 and 2% per year thereafter. The effect of alternative gas price escalation scenarios is discussed in Section C of this chapter.

Discussion with a representative of the insurer of the City of Glenwood Springs resulted in an assumed insurance rate of \$1.50 per \$100 of coverage. The entire system cost, including the wells, was included in the coverage.

The city pays neither property tax nor franchise tax on its activities. Instead, an in-lieu-of-tax charge is levied by the city to

compensate it for the loss of these revenues. A rate of 5% of gross revenues has been approved by the Colorado Public Utilities Commission in regards to the city's electric power distribution system; it is felt that such a rate is appropriate for the geothermal system, although the system will not fall under the jurisdiction of the CPUC as long as it remains within the city limits.

Derivations of capital cost estimates were discussed in Chapter II. The cost for replacement equipment (circulation and injection pumps) is assumed to increase at the same rate as general inflation; it is thus assumed to remain constant in real terms. Replacement capital costs are such a small part of the total cost that changes in this assumption would have virtually no effect.

Of more importance to the economic feasibility of the system is the required rate of return on the city's investment and the interest rate on any debt. Following a memorandum issued by the U.S. Department of Energy (DOE) (Ray, 1979), a rate of return of 10% on the city's equity involvement is assumed; it is beyond the scope of this study to enter into the controversial area of selecting appropriate social discount rates. Similarly, a real debt interest rate of 3%, as suggested by DOE, is assumed.

C. Base Case Analysis

Table III-3 presents the levelized costs and percentage distribution of the costs for the base case system. The levelized unit cost of \$5.37/mm Btu compares favorably with the levelized value, \$8.92/mm Btu, of the displaced natural gas. This result may be surprising at first glance; many economic analyses of direct application geothermal projects conclude that the projects are marginally feasible at best. The high economic viability of the system is understandable after it is realized that the project has a number of important points in its favor. First, the resource is reasonably well understood, thus lowering exploration

TABLE III-3

LEVELIZED LIFE CYCLE COSTS FOR BASE CASE SYSTEM (500 gpm)

	<u>Levelized Cost \$ 1980</u>	<u>Levelized Cost \$/mm Btu</u>	<u>Percent of Total</u>
Capital recovery charge	47,660	2.58	48
Operation and maintenance			
Labor	7,200	.39	7
Electricity	11,548	.63	12
Peaking fuel	16,473	.89	17
Insurance	11,385	.62	11
In-lieu-of-tax payments	<u>4,961</u>	<u>.26</u>	<u>5</u>
TOTAL	99,227	5.37	100

Present value of system costs = \$1,635,503

Present value of displaced gas = \$2,715,171

Present value at system savings = \$1,079,668

Estimated discretionary retrofit cost = \$75,200 to \$277,400

and site selection costs. Second, the resource is close (less than 4,000 feet) to users. Third, the users are large, which tends to lower the retrofit and the distribution costs. Fourth, the geothermal wells are relatively shallow (less than 800 feet) and are not expected to encounter highly unfavorable geologic conditions.

Finally, and perhaps most importantly, a high utilization factor is implicit in the design of the system. On an annual basis, the system will meet 90% of the heat load with geothermal energy. The remaining 10% of the demand will be met by a relatively low cost peaking system; it was found that the installation of a geothermal system that does not require a non-geothermal peaking capacity would have doubled the capital cost of the system.

Table III-3 also shows that capital costs account for nearly half of the cost of the system. The largest single operational cost is the charge for peaking fuel which accounts for 17% of the total system levelized cost. Electricity costs amount to 12% of the total. It is interesting to note that the insurance charge is nearly as large as the labor charge and the in-lieu-of-taxes charge combined.

The table also shows the present value of the costs of the geothermal system, the present value of the displaced natural gas and the resultant present value of system savings maximum allowable retrofit cost. The PVSS of \$1 million far exceeds the estimated range of discretionary retrofit costs given in Table III-1 of \$75,200 to \$277,400. The system is clearly economically viable.

As discussed earlier, it is assumed the user will be responsible for meeting any discretionary retrofit costs that are required. Under the Crude Oil Windfall Profits Act of 1980, such investments qualify for a 15% tax credit. In addition, such investments qualify for a 10% tax credit from the State of Colorado. It is not believed that such investments qualify for the standard federal investment tax credit of 10%,

which excludes buildings, since they are part of a building. These tax credits are applicable to retrofit of additional radiator area, replacement radiators, or conservation measures.

Of course, tax credits only have an impact on taxpaying entities. The government organizations that will provide the majority of the system users will not benefit from the credits. However, any taxpaying firm that joins the system will receive a subsidy of 25% of the value of the retrofit investment.

Table III-4 presents the yearly cash flows, in 1980 dollars, for the project. These cash flows, however, include only mandatory retrofit costs. Thus, the apparent savings of \$9,500 in the first year of operation is somewhat misleading. For example, if a retrofit cost of \$75,200 is financed over a five year period, the annual loan payment will be \$16,394; a \$9,500 savings in the first year is, in reality, a \$6,894 operating loss. However, savings during the second year of operation exceed the loan payment (due to the anticipated increase in the cost of natural gas).

The table also shows the result of a high front-end cost, capital intensive project. Since most costs escalate slowly, if at all, the annual system operating cost increases from \$89,421 to \$109,479 (during the 30 year operating life). The value of the displaced natural gas, on the other hand, increases from \$98,907 to \$237,575 over the same period. The information is presented graphically in Figure III-1.

D. Sensitivity Analyses

Sensitivity analyses were performed for the base case system for a number of key, but uncertain or unknown, parameters. These parameters include the system size, capital cost, operating cost, debt ratio and the wellhead temperature.

TABLE III-4

ANNUAL CASH FLOW STATEMENT FOR BASE CASE SYSTEM, 1980 \$

Cost Component	Year															
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Capital Recovery	47,660	47,660	47,660	47,660	47,660	47,660	47,660	47,660	47,660	47,660	47,660	47,660	47,660	47,660	47,660	47,660
Labor	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200
Electricity	8,814	9,299	9,810	10,350	10,919	11,028	11,138	11,250	11,362	11,476	11,591	11,707	11,824	11,942	12,061	12,182
Peaking Fuel	9,891	10,880	11,968	13,164	14,481	14,771	15,066	15,367	15,675	15,988	16,308	16,634	16,967	17,306	17,652	18,005
Insurance	11,385	11,385	11,385	11,385	11,385	11,385	11,385	11,385	11,385	11,385	11,385	11,385	11,385	11,385	11,385	11,385
In-Lieu-of-Tax Charge	4,471	4,549	4,633	4,724	4,823	4,844	4,866	4,887	4,910	4,932	4,955	4,978	5,002	5,026	5,050	5,075
Total Cost	89,421	90,973	92,656	94,483	96,468	96,888	97,315	97,749	98,192	98,641	99,099	99,564	100,038	100,519	101,008	101,507
Value of Displaced Gas System Savings	98,907	108,797	119,677	131,645	144,809	147,706	150,660	153,673	156,746	159,881	163,079	166,340	169,667	173,060	176,522	180,052
	9,486	17,824	27,021	37,162	48,341	47,818	53,345	55,924	58,554	61,240	63,980	66,776	69,629	72,541	75,514	78,545

Cost Component	Year															Present Value (at 4.4%)
	17	18	19	20	21	22	23	24	25	26	27	28	29	30		
Capital Recovery	47,660	47,660	47,660	47,660	47,660	47,660	47,660	47,660	47,660	47,660	47,660	47,660	47,660	47,660	785,545	
Labor	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200	118,672	
Electricity	12,304	12,427	12,551	12,677	12,803	12,931	13,061	13,191	13,323	13,456	13,591	13,727	13,864	14,003	190,343	
Peaking Fuel	18,365	18,733	19,107	19,489	19,879	20,277	20,682	21,096	21,518	21,948	22,387	22,835	23,292	23,757	271,517	
Insurance	11,385	11,385	11,385	11,385	11,385	11,385	11,385	11,385	11,385	11,385	11,385	11,385	11,385	11,385	187,651	
In-Lieu-of-Tax Charge	5,101	5,127	5,153	5,179	5,207	5,234	5,262	5,291	5,320	5,350	5,380	5,411	5,442	5,474	81,775	
Total Cost	102,015	102,532	103,056	103,590	104,134	104,687	105,250	105,823	106,406	106,999	107,603	108,218	108,843	109,479	1,635,503	
Value of Displaced Gas System Savings	183,653	187,326	191,073	194,894	198,792	202,768	206,823	210,960	215,179	219,483	223,872	228,350	232,917	237,575	2,715,171	
	81,638	84,794	88,017	91,304	94,658	98,081	101,573	105,137	108,773	112,484	116,269	120,132	124,074	128,096	1,079,668

Figure III-1

Year After System Startup

COMPARISON OF ANNUAL HEATING COSTS: BASE CASE

The natural gas price escalation rate was varied in all of the above analyses. Scenario 1 is the base case gas price escalation rate: 10% annual price increase to 1984 and 2% annual increase thereafter. In Scenario 2, the gas price is assumed to rise at half the rate in Scenario 1 or 5% annually to 1984 and 1% thereafter. No increase in gas price is forecast in Scenario 3.

For ease of comparison, the sensitivity to each parameter is measured as the present value of system savings. If the PVSS is greater than the appropriate radiator retrofit cost shown in Table III-1, the system is clearly economic. On the other hand, if the PVSS is less than the conservation retrofit cost, the system is clearly uneconomic. If the PVSS is within the range of retrofit costs, the system is considered to be marginally economic.

Sensitivity to System Size. Options A and C (250 gpm and 1,000 gpm, respectively) are intended to examine the impact on economic feasibility of constructing systems larger or smaller than the base size of Option B (500 gpm). Table III-5 shows the present value of system savings as a function of system size and gas price scenario.

The PVSS under Scenario 1 are \$101,482, \$1,079,668 and \$3,053,506 for Options A, B and C, respectively. For Options B and C, the PVSS's far exceed the estimated discretionary retrofit costs shown in Table III-1. However, the upper end of the range estimated for discretionary retrofit costs for Option A (\$138,700) exceeds the system savings (\$101,482). Thus, Option A is marginally economic under the base case assumptions while Options B and C are clearly feasible.

The results of the other gas price scenarios do not appreciably change these conclusions. Option A is clearly uneconomic under Scenarios 2 and 3, while Option C is clearly economic. Option B is economic under Scenario 2 but only marginally economic under Scenario 3.

TABLE III-5

PRESENT VALUE OF SYSTEM SAVINGS (1980 \$) AS
A FUNCTION OF SYSTEM SIZE AND NATURAL
GAS PRICE SCENARIO*

<u>System Size</u>	<u>Price Scenario 1</u>	<u>Price Scenario 2</u>	<u>Price Scenario 3</u>
250 gpm (A)	\$ 101,482	\$ -173,690	\$ -383,937
500 gpm (B)	1,079,668	529,410	108,911
1000 gpm (C)	3,053,506	1,953,050	1,111,926

*Natural gas price scenarios:

Scenario 1 (base case): 10% annual price increase to 1984; 2% annual increase thereafter

Scenario 2: 5% annual price increase to 1984; 1% annual price increase thereafter

Scenario 3: No price increase over life of system

Under all scenarios: 5.5% annual electricity price increase to 1984; 1% annual increase thereafter; no real price increases for labor and insurance.

Sensitivity to Capital Cost. The majority of the capital cost estimates are believed to be accurate to within 20%. However, the well costs form a large part of the total capital cost and are now known with great accuracy. In order to determine the impact of deviations from the estimated capital costs on project feasibility, PVSS's were calculated assuming total capital costs of 50%, 75%, 125% and 150% of the base value, under gas price scenarios 1 and 2. The results are summarized in Table III-6.

As can be seen from the table, the system is economic assuming a 50% capital cost overrun from the base value and assuming gas price Scenario 1. However, the system is marginally economic for a 25% cost overrun under Scenario 2 and is clearly uneconomic for a 50% overrun under Scenario 2.

The sensitivity to capital cost overruns is not as alarming as it might initially seem. Only the well costs are not known within an accuracy of 20%; many other cost estimates are from manufacturers' quotes and consequently are highly accurate. With estimated well costs of \$268,000 and a total system capital cost of \$786,000, actual well costs must be more than double the estimated costs if a 50% cost overrun is incurred, assuming a 20% overrun on non-well costs. Well costs of this magnitude are highly unlikely. Thus, under reasonable variations in capital cost estimates and natural gas pricing scenarios, the geothermal system is considered to be economically feasible.

Sensitivity to Operating Costs. Labor, electricity, peaking fuel (natural gas), insurance costs and in-lieu-of-tax charges are explicitly included in the operating and maintenance costs. Current values of these costs are known to a high degree of accuracy; the rates of change of the costs, however, are not well known. Rather than creating a set of escalation rate scenarios and determining the economic feasibility under these scenarios, a sensitivity analysis approach similar to that used for measuring the sensitivity to capital costs was used. Present

TABLE III-6

PRESENT VALUE OF SYSTEM SAVINGS (1980 \$)
CAPITAL COST AND GAS PRICE SCENARIOS*
FOR OPTION B (500 gpm)

<u>Percentage of Capital Cost</u>	<u>Scenario 1</u>	<u>Scenario 2</u>
50%	1,591,871	1,041,613
75%	1,335,786	785,512
100% (base case)	1,079,668	529,410
125%	823,566	273,292
150%	567,465	17,191

(c.f. estimated range of discretionary retrofit costs: \$75,200 to \$277,400.)

*For definition of scenarios, see footnote, Table III-5.

Scenario 1. However, the system is marginally economic for a 25% cost overrun under Scenario 2 and is clearly uneconomic for a 50% overrun under Scenario 2.

The sensitivity to capital cost overruns is not as alarming as it might initially seem. Only the well costs are not known within an accuracy of 20%; many other cost estimates are from manufacturers' quotes and consequently are highly accurate. With estimated well costs of \$268,000 and a total system capital cost of \$786,000, actual well costs must be more than double the estimated costs if a 50% cost overrun is incurred, assuming a 20% overrun on non-well costs. Well costs of this magnitude are highly unlikely. Thus, under reasonable variations in capital cost estimates and natural gas pricing scenarios, the geothermal system is considered to be economically feasible.

Sensitivity to Operating Costs. Labor, electricity, peaking fuel (natural gas), insurance costs and in-lieu-of-tax charges are explicitly included in the operating and maintenance costs. Current values of these costs are known to a high degree of accuracy; the rates of change of the costs, however, are not well known. Rather than creating a set of escalation rate scenarios and determining the economic feasibility under these scenarios, a sensitivity analysis approach similar to that used for measuring the sensitivity to capital costs was used. Present values of system savings were calculated assuming actual operating costs of 50%, 75%, 125% and 150% of the base case value, using natural gas price Scenarios 1 and 2. The results are summarized on Table III-7.

As in the other cases described thus far, the geothermal system becomes uneconomic only in the worst case: lower than expected increases in the cost of natural gas and a 50% increase in estimated operating costs. The likelihood of both events occurring is rather small. Thus, the system is considered to be economically viable under likely deviations from expected operating costs.

TABLE III-7

PRESENT VALUE OF SYSTEM SAVINGS (1980 \$) AS
 FUNCTION OF OPERATING COSTS AND GAS PRICE
 SCENARIOS* FOR OPTION B (500 gpm)

<u>Percentage of Operating Costs**</u>	<u>Scenario 1</u>	<u>Scenario 2</u>
50%	1,504,655	889,655
75%	1,292,170	677,170
100% (base case)	1,079,668	464,678
125%	867,199	252,199
150%	654,714	39,714

(c.f. estimated range of discretionary retrofit costs: \$75,200 to \$277,400.)

*For definition of gas price scenarios, see Table III-5.

**A decrease in operating cost due to a lower natural gas price was not considered, as this is considered highly unlikely to occur.

values of system savings were calculated assuming actual operating costs of 50%, 75%, 125% and 150% of the base case value, using natural gas price Scenarios 1 and 2. The results are summarized on Table III-7.

As in the other cases described thus far, the geothermal system becomes uneconomic only in the worst case: lower than expected increases in the cost of natural gas and a 50% increase in estimated operating costs. The likelihood of both events occurring is rather small. Thus, the system is considered to be economically viable under likely deviations from expected operating costs.

Sensitivity to the Debt Ratio. Two different costs of capital have been assumed in the analysis thus far. First, equity capital investments are assumed to require a 10% return per year. Second, debt is charged a real interest rate of 3% per year. In the base case, the system is assumed to be financed using 20% equity and 8% debt, which results in a debt ratio of 80% and weighted cost of capital of 4.4%. Present values of system savings, assuming a range of debt ratios, are shown in Table III-8.

Due to the lower cost of debt financing, it is not surprising that as that debt ratio decreases, the economic feasibility of the system also decreases. At a 50% debt ratio, the system is clearly economic. However, at 0% debt (100% equity), the present value of system savings is in the middle of the range of estimated discretionary retrofit costs and is therefore marginally economic. It should be noted that it would be virtually impossible for a city the size of Glenwood Springs to finance the geothermal entirely out of equity. Possible financing structures are discussed in more detail in Part E of this Section.

Sensitivity to Wellhead Temperature. Under the design approach used in this study, changes in wellhead temperature affect primary heat exchanger costs and retrofit costs. Table III-9 shows the PVSS for base case wellhead temperatures between 140°F (60°C) and 180°F (82°C). As can be seen, the PVSS is virtually unaffected by the changes in temperature.

TABLE III-8

PRESENT VALUE OF SYSTEM SAVINGS (1980 \$) AS
A FUNCTION OF THE DEBT RATIO
FOR OPTION B (500 gpm)

<u>Debt Ratio</u>	<u>Scenario 1*</u>
0%	166,112
50%	627,310
80% (base case)	1,079,668
100%	1,797,874

(c.f. estimated range of discretionary retrofit costs: \$75,200 to \$277,400.)

*Scenario 1 (base case): 10% annual increases to 1984; 2% annual increase thereafter.

TABLE III-9

PRESENT VALUE OF SYSTEM SAVINGS (1980 \$) AS
A FUNCTION OF WELLHEAD TEMPERATURE FOR
OPTION B (500 gpm)

<u>Wellhead Temperature, °F</u>	<u>Scenario 1*</u>
140	1,029,364
150	1,075,580
160 (base case)	1,079,668
170	1,083,327
180	1,086,689

(c.f. estimated range of discretionary retrofit costs: \$75,200 to \$277,400.)

*Scenario 1 (base case): 10% annual gas price increase to 1984;
2% annual increase thereafter.

As shown in Table III-1, a radiator retrofit cost of \$420,100 was estimated for a 140°F (60°C) geothermal resource. The PVSS of \$1,029,364 far exceeds the estimated discretionary retrofit cost. Thus, wellhead temperature has only a very small impact on system feasibility.

E. System Financing

The preceding analysis has shown both Option B (500 gpm) and Option C (1,000 gpm) to be economically feasible under a wide range of realistic parameter values. This section identifies various sources of project financing and discusses some issues associated with those sources. Five sources of funding have been identified: the city itself; municipal bonds (either general obligation or revenue); the User-Coupled Confirmation Drilling Program, the Geothermal Loan Guarantee Program and private developers.

One Hundred Percent Equity Financing. One possible source of funds might appear to be the city. However, it is not believed possible for the city to pay approximately \$750,000 out of cash reserves for the installation of the system. In addition, the sensitivity analysis has shown such a scheme to be only marginally economic. Thus, the possibility of 100% equity financing is immediately rejected.

Bond Financing. The most conventional source of funds for a large municipal improvement project is the issuance of bonds. Municipal bonds are considered here to be of two types, general obligation bonds and revenue bonds. Municipal bonds are backed by the full faith and credit of the city. In evaluating such bonds, buyers primarily depend upon the credit rating of the municipality, not on the merits of the project. Glenwood Springs has a good credit rating. The State of Colorado imposes a ceiling on general obligation borrowing by municipalities; the system under consideration will not cause the city to even approach the limit.

An additional limitation on general obligation borrowing is the required approval of the voters. A recent bond election, in November 1978, to provide funds for a municipal complex, failed. No attempt has been made to assess the possibility of voter approval of a bond issue for the purpose of constructing a geothermal heating system.

Use of general obligation bonds has definite advantages. First, little or no equity participation is required of the city. Second, the costs of borrowing will most likely be lower than for other conventional sources of funding. In contrast, revenue bonds are repaid through revenues generated by the affected project. Such bonds are not affected by state imposed credit limitations. However, the project is evaluated by the bond market very carefully. If the risk is believed to be high, the bonds will be bought at a high cost to the city, if they are bought at all. Geothermal projects, particularly geothermal projects for which the first well has yet to be drilled, will be judged to be high risk. However, the possibility of selling the bonds for the subject geothermal system cannot be eliminated. It should also be noted that the interest rate on a revenue bond will generally be higher than the interest rate on a corresponding general obligation bond, due to the increased risk involved.

User-Coupled Confirmation Drilling Program. The Department of Energy has recently begun a program to significantly lower the financial risk involved in exploring for and confirming moderate and low temperature geothermal resources. This program, the User-Coupled Confirmation Drilling Program, allows DOE to pay 90% of the costs of an unsuccessful drilling program. DOE will also pay 20% of the costs of a completely successful drilling program. For wells that are neither completely successful nor completely unsuccessful, DOE may pay a variable amount dependent upon the degree of success and a scale submitted by the proposer and approved by DOE. By decreasing the financial risk of exploration, it is hoped that project financing will be both cheaper and easier to obtain.

DOE has specified four conditions which must be met by the proposer. The proposer must:

- Have a site with hydrothermal potential
- Have an intended end use or have an arrangement with a potential user with an end use
- Have solutions to institutional barriers
- Be able to provide a self-sustaining financial package

The city readily meets the first three conditions; the financial package is the subject of this section. The impact of this program on the ease and terms under which financing can be obtained is unclear. However, should the city decide to pursue the development of the system, the use of the program should be investigated in detail. It should be noted that the program will not significantly lower the cost of a successful system; DOE will pay only \$53,600 of the \$759,000 capital cost. The program, however, may make funds available that otherwise may not have been available. For example, use of this program to drill and test wells may lead to a proven resource. The bond market will be much more receptive to a revenue bond issue if the resource is proven. If 20% equity participation is required and 80% debt financing can be arranged, then the city's equity share to drill and test a well may amount to less than \$40,000.

Geothermal Loan Guarantee Program. A second program operated by DOE is the Geothermal Loan Guarantee Program (GLGP). Under this program, the U.S. Government will guarantee up to 100% of the value of a loan that meets a number of strict criteria. The most important criterion is the economic viability of the project. The loan applicant must also arrange the financing package. However, the government may become involved in the negotiation of the terms. As of June 1980, however, only four loans had been guaranteed since the program was created by Congress in 1974. Steps have been taken to improve the performance of the program.

The most serious drawback to the use of the GLGP by the City of Glenwood Springs is the 25% equity requirement. For the base case system, this amounts to equity participation of \$190,000. It is unlikely that the City of Glenwood Springs can provide funds of that magnitude without resorting to a bond issue. However, discussions with Ken Bromberg of the Geothermal Loan Guaranty Program Office indicate that financing packages can be put together that diminish the importance of the equity criterion.

Private Developers. It has been recommended elsewhere in this report that the system be owned and operated by the City. Arguments for city ownership dealt primarily with operation and maintenance considerations. A variant of this approach, which maintains the advantages of city ownership, is for a private developer to drill the wells and sell the city the hot water at the wellhead. The city is thus responsible for all operation and maintenance costs, except for the wells themselves. Private developers, in turn, may take advantage of the user-coupled Confirmation Drilling Program and the investment tax credits discussed earlier. The small equity investment, combined with a loan guarantee and investment tax credits could be profitable for the private developer, while removing the risk to the city.

Financing Conclusions. Discussion with representatives of the Geothermal Loan Guarantee Program and with municipal bond brokers indicate that a financial package can be created that will provide the funds necessary to construct the system; no insurmountable hurdles have been foreseen. Further, these funds may be provided at a cost lower and at a debt ratio lower than that assumed in the economic analysis. Thus, it is concluded that the financing of the system should not provide any barriers to the development of the system; selection of a particular method of financing system must await a more detailed analysis, should the city desire to install a geothermal heating system.

F. Pricing Issues

Determination of the selling price of the geothermal fluid or energy to non-city users can be very difficult. For example, it is common in district heating systems for the delivered unit energy cost from the geothermal system to be initially higher than corresponding conventional system cost. The advantage of the geothermal system arises from the much lower increase in system costs over time and potential users must be made to understand the advantage.

However, as was shown in Table III-4, the annual system costs are lower than the cost of the displaced gas in all but the first year. By the end of the project, the annual savings climbs to \$128,000. Thus, the economic advantage of joining the system is clear.

One complicating aspect of the problem, the payment of retrofit costs, remains to be solved. As discussed earlier, if the building owners are required to pay for any retrofit work necessary, the owners may "lose" money during the first few years of the project, if the city simply sets rates so as to recover its costs. The city would thus let the owners decide for themselves if the later savings justified the early costs.

The city could instead decide to stimulate investment in geothermal energy and membership in the system by guaranteeing that the delivered unit cost of energy, including retrofit costs, is less than the corresponding conventional cost. DRI believes this approach has a number of drawbacks. First, such an approach would require that individual rates be set for each consumer. The cost of the effort could be high and the legality questioned. Second, the city itself would be forced to pay the subsidy in the early years, intending to recapture those funds in later years. Depending upon the degree to which the city reserves were drawn down to pay for the construction of the system, this may not be possible.

Finally, and perhaps most importantly, it is not believed that such artificial stimulation is necessary. If the cost advantage of participating in the system is sufficiently clear, the subsidy discussed above will not result in any additional users. The city may need to point out the advantages to the affected parties, however.

Another pricing issue is the billing method. Specifically, the decision of whether to bill for energy used or fluid used must be made. It is recommended that billing be done on a flow basis for two basic reasons. First, techniques for measuring water flow are readily available and the equipment to do so is inexpensive. It is not as easy to measure energy consumed, although it is possible.

Secondly, and more importantly from a policy point of view, is that a flow metering method encourages maximum use of geothermal energy; a user is charged the same amount for a given flow volume regardless of whether the temperature drop across his building's heating system is 10°F or 30°F. As an example, consider a building that is not only heated geothermally, but uses geothermal energy to heat potable water. For normal uses, the water leaving the space heating system at a temperature of 130°F (54°C) could serve to heat water to 120°F (48°C). If still hotter water is required, a small amount of the hot water entering the building at 160°F (71°C) could be used to heat already preheated water. The only cost to the building owner would be the capital costs of the plumbing and additional heat transfer equipment required and a small charge for the additional circulation water used to heat the preheated water.

G. Summary and Conclusions

This chapter has investigated three economic issues of direct concern to the construction of a geothermal heating system in the city of Glenwood Springs. These issues are economic feasibility, financing and pricing.

The base case system (Option B, 500 gpm) has been shown to be economically viable under a wide range of realistic values for a number of important parameters. Sensitivity analyses were performed for the system size, capital cost, operating cost, natural gas price escalation rate, debt ratio and wellhead temperature. Due to the economies of scale inherent in the system design, Option C (1,000 gpm) appears to yield lower energy costs than the 500 gpm system. However, the market for a 1,000 gpm system has not been proven.

Construction of the geothermal system can be funded in several different ways. All of these methods require some form of equity participation, although the issuance of general obligation bonds will tend to minimize direct city equity involvement. Also, two federal loan guaranty programs exist which may serve to make bond issues easier and less expensive to sell. However, one of the programs requires a 20% equity involvement and the second requires 25% equity participation. Proper preparation of a finance package will require further work on the part of the City of Glenwood Springs, although no insurmountable barriers to financing the project have been foreseen.

The geothermal energy produced should be priced at the total economic cost of production. However, it is proposed that the city should bill according to water used, rather than energy consumed. Such a billing method will lead to the maximum use of the geothermal resource without requiring the city to subsidize users in the early years of the project.

IV. GEOTHERMAL RESOURCES

A. Resource Assessment

The community of Glenwood Springs is located 150 miles west of Denver, along Interstate 70, and is the county seat for Garfield County with an area population greater than 7000 (Kane, 1975). Glenwood Springs lies at the confluence of the Roaring Fork and Colorado rivers between the foothills of the White River Plateau to the north and the Grand Hogback to the west. This region is known for its abundant energy resources of coal, uranium, and oil shale, and more recently for its potential geothermal energy resources.

Surface expressions of subterranean heat are very prevalent in the Glenwood Springs area where the heat is manifested in up to 31 hot springs (Figure IV-1) with massive basalt flows of recent Quaternary age common throughout the area. Glenwood Springs is named for the many hot springs that lie along the banks of the Colorado River for approximately one mile within town. Of the many hot springs in the area the Yampah Hot Spring has the greatest discharge rate of any hot spring in Colorado (Pearl, 1979) at 2263 gallons per minute (gpm). Other hot springs in the area have varying flow rates from as low as one to two gallons per minute up to 150 gpm. Surface temperatures are uniform throughout the springs in the area ranging from 110° to 125°F (43°-52°C). These hot springs have the highest salinity in Colorado (Pearl, 1972) with total dissolved solids ranging from 17,000 to 20,000 mg/l. The U.S. Bureau of Reclamation (1976) has calculated that the hot springs within a 16 mile region between Glenwood Springs and Dotsero discharge 500,000 tons per year of dissolved solids into the Colorado River.

Geology. The localized geology of the Glenwood Springs region is controlled by the White River Uplift to the north. Glenwood Springs lies on the highly faulted and fractured flanks of this very large domal uplift and the geology at Glenwood Springs is characterized by a Paleozoic

Figure IV-1. Location of hot springs at Glenwood Springs, Colorado. The approximate flow rates of the hot springs are represented by:

150 gpm = ● , 50 - 150 gpm = ⊙ , 50 gpm = *

section primarily composed of marine sandstone, dolomite, limestone, and shale. Overlying these Paleozoics is a thick sequence of Mesozoic shales and sandstones which are capped by Tertiary to Quaternary basalts. Trending east-west through Glenwood Springs (inferred) is the Storm King thrust fault. This low angle thrust fault is projected to trend through the hot springs areas and "may" be a controlling feature of the geothermal resources. Figure IV-2 is a detailed geologic map of the Glenwood Springs vicinity.

The stratigraphy of the sedimentary units and basalt flows is described as follows:

Precambrian - These rocks are exposed to the east of Glenwood Springs at the Rio Grande Railroad tunnel and across the Colorado River at the highway tunnel of Interstate 70. These Precambrian rocks are predominantly metamorphosed schists and greenstones with some granitic and pegmatite intrusions (Bass and Northrop, 1963).

Sawatch Quartzite (Late Cambrian) - This unit consists of regularly bedded sandstone, quartzitic sandstone and quartzite which forms sheer cliffs 400 to 500 feet high. There are a few thinly-bedded dolomites interbedded with light greenish-gray shale. (Koulet and Armstrong, 1978).

Dotsero Formation (Cambrian-Ordovician) - The Dotsero Formation is considered separate from the overlying Manitou formation and includes two members: the Glenwood Canyon Member and the Clinetop Algao Limestone Member. The Dotsero Formation is 96 to 106 feet thick consisting of interbedded flat-pebble limestone and dolomite conglomerate, dolomite and minor amounts of shale. (Koulet and Armstrong, 1978).

Manitou Formation (Early Ordovician) - This unit includes portions of the upper half of the underlying dolomites of the Dotsero Formation as well as two distinct members of its own. The Dead Horse Conglomerate Member consists largely of thin beds of gray flat-pebble limestone conglomerate interbedded with greenish-gray, calcareous shale and some beds of limestone and dolomite. The upper member is the Tie Gulch Dolomite Member of regular and thin-bedded dolomite. The overall thickness of the Manitou Formation is from 80 to 155 feet. (Koulet and Armstrong, 1978).

Qal, Qt - Alluvium and terrace
gravels
Qtr - Travertine
Qtb - Basalt flows
PIPm - Maroon Fm.
IPp - Paradox Fm.

IPbm - Belden & Molas fms.
MI - Leadville Limestone
Dc - Chaffee Fm.
Ocmd - Manitou & Dotsero fms.
Cs - Sawatch Quartzite
pC - Precambrian

Figure IV-2 Geologic map of the Glenwood Springs area, Colorado (Bass and Northrop, 1963). Cross-section A-A' is shown in Figure 3.

Chaffee Formation (Devonian) - The Chaffee Formation unconformably overlies the Manitou Formation and is divided into two members. The lower member (Parting Member) is from 63 to 95 feet thick consisting of interbedded light-green shale, black shale, light-tan glassy quartzite with some dolomite and sandy dolomite. The upper member (Dyer Member) consists of thick units of limestone and dolomite. The overall thickness of the Chaffee Formation is about 246 feet. (Koulet and Armstrong, 1978).

Leadville Limestone (Mississippian) - It is believed the Leadville Limestone may be the reservoir for the shallower geothermal fluids at Glenwood Springs. All of the local hot springs flow from outcrops of Leadville Limestone or from overlying river alluvium or fractures above the Leadville.

The Leadville ranges in thickness from 175 to 225 feet and consists primarily of limestone, interbedded in the lower third with dolomite and dark-gray chert. Bass and Northrop (1963) state that the highly porous and cavernous voids within the Leadville may be filled with steam. (Koulet and Armstrong, 1978).

Molas Formation (Pennsylvanian) - This is a very thin, dull, purplish-red clay unit containing smooth nodules and boulders of chert. The maximum thickness of the Molas Formation is 25 feet. (Koulet and Armstrong, 1978).

Belden Formation (Pennsylvania) - At Glenwood Springs the Belden Formation has a thickness of 600 feet but at other localities in the Glenwood Canyon its thickness is up to 1000 feet. The Belden is characterized by thick sequences of dark-gray shale containing thin beds of fossiliferous limestone interbedded with black shale, micaceous sandstone, and thick beds of gritstone. (Koulet and Armstrong, 1978).

Paradox Formation (Pennsylvania) - The Paradox Formation is most known for its thick layers of gypsum (60 to 160 feet thick) which are interbedded with units of fissil black shale in varying thicknesses. The overall thickness of the Paradox is up to 1580 feet. (Koulet and Armstrong, 1978).

Maroon Formation (Pennsylvanian-Permian) - The Maroon is noted for its thick sequence of redbeds consisting of shale, siltstone, sandstone, and conglomerate. Near the top of this formation is a 400 foot thick unit of gray sandstone overlying the redbeds. The overall thickness of the Maroon Formation is 3350 feet. (Bass and Northrup, 1963).

Volcanics (Tertiary-Quaternary) - Massive and widespread basalt flows occur to the southwest and southeast of Glenwood Springs, extending to the east of Dotsero. These basalts are very young and probably issued from numerous vents.

Travertine (Holocene) - Massive hot spring deposits of travertine (CaCO_3) extend continually for 1.5 miles along the north bank of the Colorado River. These travertine deposits cover 80 acres and are from three to forty feet thick beneath the present municipal golf course just northwest of town.

The dominant structural trend in the Glenwood Springs area is represented by gently sloping sedimentary beds dipping at 40° to the southwest. This regional dip is the result of the White River Uplift which is a broad domal feature centered approximately 20 miles north of Glenwood Springs. The White River Uplift is probably responsible for the large number of high angle normal faults in the Glenwood Springs area (Figure IV-2). These faults generally trend to the northwest with the down-dropped block to the northeast at an average displacement of 50 to 400 feet. The major fault trend in this region is the Storm King thrust fault which trends east-west to within three miles of Glenwood Springs. Bass and Northrop (1963) infer that the Storm King thrust fault trends directly into Glenwood Springs and may directly control fluid discharge at the Yampah Hot Spring as well as controlling all the hot water flow along the Colorado River. The Storm King thrust fault is dipping to the north at a very low angle (possibly as low as 10°) and its probable subsurface relation with other units is projected in Figure IV-3.

In the Glenwood Springs area there are many surface expressions of volcanic activity within the relatively recent past. Miocene to Pleistocene basalt flows as thick as 1000 feet are found throughout the area. Lava flows southwest of town (sections 17 and 28, T.6S., R.89W.) are extremely young as they were extruded after the erosional formation of the Roaring Fork valley. This is shown by basalts extending from a relatively flat plateau down the slopes toward the river (Bass and Northrop, 1963). The lava flows southwest of Glenwood Springs were probably emitted from Sunlight Peak, eight miles southwest of town.

The basalts southeast of Glenwood Springs "may" have originated in the Dotsero area eighteen miles to the northeast. There is postulation that these lavas may be derived from Willow Peak and the Dotsero Crater

Figure IV-3 Proposed geologic cross-section through the Glenwood Springs area, Colorado (modified from Bass and Northrop, 1963). Profile line is shown in Figure

(Bass and Northrop, 1963). The Dotsero Crater probably does contain sufficient latent heat to contribute to an active geothermal system. The lava flows from the Dotsero Crater are superimposed on the existing topography and at one time blocked the Eagle River. The resulting lake sediments and silts overlie preceding Wisconsin glaciation (Landon, 1933) and this dating, combined with the superimposed lava flows, indicates the Dotsero Crater may be the youngest volcanic activity in Colorado and has occurred within the past 9500 years. The relatively confined nature of the basalt flows of the Dotsero Crater (an areal extent of one-half mile by one mile) do not lend evidence that they directly relate to those basalts immediately southeast of Glenwood Springs. Therefore, Bass and Northrop's (1963) theory that the lavas southeast of Glenwood Springs may have been partially derived from the Dotsero Caldera may be invalid.

The alluvial deposits along the Colorado and Roaring Fork river floodplains provide the easiest recoverable groundwater resource in the area. Most wells drilled in these formations range in depth from several feet to 200 feet. The expected yields from these wells range from 0 to 500 gpm. (Fox & Associates, 1975). The Leadville Limestone is also a known ground-water bearing aquifer in the Glenwood Springs region. It appears as if most hot springs in the immediate area discharge either directly from the Leadville Limestone or from fractures and alluvium immediately overlying it. Those groundwaters in the Leadville are generally under artesian pressures and these aquifers contain very large volumes of fluids as shown by the discharge rate of over 2200 gpm from the Yampah Hot Spring in the Leadville. The older sedimentary and igneous formations will yield water only where a fracture is easily available to be tapped. Wells in this category are estimated to produce from 0 to 100 gpm, but generally greater than 150 feet (Fox and Associates, 1975). It is generally believed that groundwater reservoirs in the Glenwood Springs region are recharged by meteoric precipitation and by natural seepage and recharge from the major rivers and streams. Groundwaters occur under water table conditions or under artesian pressures, depending on the immediate structure and stratigraphy.

Geochemistry. There have been numerous investigations and studies of the geochemical properties of the hot springs at Glenwood Springs. The most notable investigations are the ongoing Colorado River Water Quality Improvement Program of the U.S. Bureau of Reclamation (Bureau of Reclamation, 1976), and the geochemical sampling and modeling studies of the Colorado Geological Survey (Barret and Pearl, 1976 and 1978). The Bureau of Reclamation samples the hot springs at Glenwood Springs at eleven sampling points on a schedule of every two weeks. The primary purpose of their investigation is to continually monitor the discharge of dissolved solids and other natural pollutants into the Colorado River. The Colorado Geological Survey sampled nine different hot spring vents, from one to four times each, between 1975 and 1976. The resulting chemical analyses were calculated into the standard geochemical models derived by the USGS (Fournier and Rowe, 1966; Fournier and Truesdell, 1973 and 1974; Fournier and others, 1974) to estimate subsurface geothermal reservoir temperatures.

The results of the hot springs water sampling, and subsequent geochemical modeling by the Colorado Geological Survey calculate geothermal reservoir temperatures at Glenwood Springs to be from 130° to 175°F (54°-79°C). Several different models were used but many were disregarded due to the basic assumptions inherent within the model. The sodium-potassium-calcium geothermometer (alkali geothermometer) calculated reservoir temperatures between 265° and 365°F (129°-185°C). These calculations are probably too high based upon 1) extensive travertine deposits in the area indicating re-equilibration of the hot waters with respect to calcium which subsequently elevates the calculated temperatures, and 2) the extremely high discharge rates of the local springs should yield higher surface temperatures if the geothermal reservoir indeed had temperatures in excess of 300°F. At Glenwood Springs the most accurate reservoir temperature models appear to be those based upon silica solubilities and groundwater mixing (chalcedony-silica mixing model). The close direct correlation between the projected reservoir temperatures and the surface temperatures throughout Glenwood Springs,

combined with the very high spring discharge rates, yields the greatest validity to these geochemical models. The silica and mixing geochemical models calculate the reservoir temperatures from 130° to 175°F and these hot fluids are mixing with up to 46% cold groundwater before they are discharged at the surface (Barrett and Pearl, 1978).

Reported analyses fall within the highly saline water category as defined by the U.S. Geological Survey ($> 10,000 < 35,000$ mg/l Total Dissolved Solids; Robinove et al., 1958). TDS concentrations range from 17,000-20,000 mg/l (calculated). Na^+ and Cl^- constitute 87-89% of the total dissolved solids with Ca^{++} , $\text{SO}_4^{=}$ and HCO_3^- as the only other major ions in solution. The pH's are temperature neutral or near temperature neutral indicating that these waters are well buffered and that dissolved carbonate species probably play an important part in the overall geochemical equilibrium.

All waters are generally at or near saturation with respect to calcite (CaCO_3) and quartz ($\alpha\text{-SiO}_2$). In no case is the solubility of halite (NaCl) ever exceeded despite its high concentration in solution.

Figure IV-4 shows vector plots of the water analyses in Attachment B of Appendix A. These plots graphically describe the relationships between the five ions listed according to the legend in the upper right-hand corner of the figure. The close proximity of the lower endpoints of each vector to the 50%-50% milliequivalent per liter line shows that all analyses have good cation-anion balance closure. The tight grouping of the vectors and their similarity of slope are remarkable for groundwaters which normally show a much wider variance. The close similarity of these vectors dictates a single source for all waters sampled and strongly suggests a single geochemical regime for their production.

$\text{Na}^+ - \text{Cl}^-$ are the major dissolved species in all waters sampled. Work by several researchers has shown that chloride ion in solution remains uncomplexed while some 1-2% of the sodium will complex, forming

Figure IV-4. Vector Plot of Waters from Glenwood Springs

the ion pairs NaSO_4^- , NaHCO_3^0 , and NaCO_3^{-1} . A sample recalculation of the water analyses to a milliequivalent per liter basis is shown as Figure IV-5. Similar recalculations were made for all of the available chemical analyses. A comparison of the meq-ratio of Na^+/Cl^- for all samples shows a fairly consistent proximity to a value of 1.0 (generally between 0.98 and 1.02). This consistency strongly suggests the solution of halite (NaCl) as the source of the Na^+ and Cl^- in these waters. It is, therefore, reasonable to assume that these waters have been in contact with halite at depth before emerging as hot springs in the Glenwood area.

The only reaction of importance to equilibria involving Na^+ and Cl^- will be the solution of halite:

Subordinate reactions may be:

Of these additional reactions, (4) and (5) are pH dependent.

Ca^{++} , $\text{SO}_4^{=}$, HCO_3^- comprise the remainder of the major ions in these solutions. All three of these ions tend to form ion-pairs or complexes at elevated salinities, hence it should be borne in mind that the reported values for these ions in the water analyses represent the total ion concentration and do not necessarily reflect the speciation. Speciations of these ions are estimated in Table IV-1.

Figure IV-5

Glenwood Springs Water Analyses

Title: Big Spring

Temp. °C: 50°

pH 6.3

Ion	(ppm)	(meq/l)
HCO_3^-	387	6.4
SO_4^-	1,100	22.88
F^-	2.3	.12
Cl^-	11,000	310
$(\text{NO}_2^- + \text{NO}_3^-)$	.01	
PO_4^{-4}	.12	.004
Ca^{++}	510	26
Mg^{++}	91	7.5
Na^+	6,900	300
K^+	180	5
Li^+	0.80	.12
SiO_2	32	

$$\frac{\text{meq Na}^+}{\text{meq Cl}^-} = .97$$

$$T_{\text{SiO}_2}^\circ = 87^\circ\text{C}$$

Table IV-1

Species	% Uncomplexed	*Additional Pairs
Ca^{++}	88	CaOH^{+1} , <u>CaSO_4^0</u> , <u>CaHCO_3^{+1}</u> , CaCO_3^0 , CaF^{+1} , CaPO_4^{-1} , CaHOP_4^0 , $\text{CaH}_2\text{PO}_4^{+1}$
$\text{SO}_4^=$	62	MgSO_4^0 , <u>CaSO_4^0</u> , KSO_4^{-1} , HSO_4^{-1} , H_2SO_4^0 , <u>FeSO_4^{+1}</u> , FeSO_4^0 , <u>NaSO_4^{-1}</u>
HCO_3^-	85	$\text{CO}_3^=$, <u>H_2CO_3^0</u> , MgHCO_3^{+1} , MgCO_3^0 , <u>CaHCO_3^{+1}</u> , CaCO_3^0 , <u>NaHCO_3^0</u> , NaCO_3^{-1}

Reactions of importance to the overall geochemistry involving these species are as follows:

$$\log K_{\text{eq}} (50^\circ\text{Ro}) = -4.74^*$$

$$\log K_{\text{eq}} (50^\circ\text{To}) = -8.62$$

$$\log K_d (50^\circ\text{To}) = -6.31$$

$$\log K_d (50^\circ\text{To}) = -10.17$$

$$\log K_{\text{eq}} (50^\circ\text{To}) = -1.70$$

$$\log K_d (50^\circ\text{To}) = -13.27$$

*Predominant complexes underlined

Equation IV-6 and IV-7 represent the solution of gypsum and calcite. Equations IV-8 - IV-11 represent general carbonate equilibria and, as such, control the buffering capacity of these solutions.

It is of some interest to rewrite Equation IV-7 as:

This reaction emphasizes the pH dependency of calcite solubility, showing that calcite becomes increasingly soluble at lower pH's. When considered in conjunction with Equation IV-8 - IV-11 it becomes apparent that under conditions present at Glenwood Springs, these waters will precipitate calcite when allowed to establish equilibrium with the atmosphere. Concentrations of CO_2 in the emerging spring waters are well above the atmospheric partial pressure of CO_2 , therefore, when these solutions are equilibrated with the atmosphere, CO_2 will evolve driving Equation IV-10 to the left. This, in turn drives Equation IV-8 to the left, consuming H^+ . As a result the pH of solution will rise and calcite will precipitate by Equation IV-7a. This chain of reactions is well documented in other geothermal areas. Successful attempts have been made at East Mesa to prevent precipitation of CaCO_3 by maintaining back pressure on the well system, thus preventing the evolution of CO_2 (Booth et al., 1972). Decreased flow rates, however, may result from the use of this method.

Additional methods for controlling the precipitation of calcite including pH adjustment, sulfate addition and phosphate addition have been described (Phillips et al., 1977). The problem of calcite scaling at Glenwood Springs, though not as severe as at many other geothermal areas which are subject to two-phase flow, must nonetheless be addressed since long term buildup of scale is inevitable unless mitigating steps are taken.

*Values for equilibrium and dissociation constants taken from Helgesson (1969).

Sulfate ions present in the Glenwood Springs waters could arise from the solution of gypsum or other soluble salts or from the oxidation of sulfide minerals and subsequent conversion of sulfur to sulfate. The eventual fate of $\text{SO}_4^{=}$ in solution is controlled by the solubility of gypsum, the least soluble of the sulfate salts of concern in these waters. Figure IV-6 shows a log activity plot for the co-precipitation of calcite and gypsum from waters containing the required ions. Representative Glenwood water analyses are plotted against lines representing the saturation limits for both species at the temperature and salinity of the water samples. Although many of the waters reported are oversaturated with respect to calcite, none are oversaturated with gypsum. The precipitation of gypsum from these solution requires that not only sufficient sulfate be present, but also that enough excess calcium remain from the competing calcite precipitation reaction to exceed the gypsum solubility limit.

The minor and trace element composition at a typical Glenwood Springs water is presented in Table IV-2. The concentrations of all species with the exception of boron are well within normal ranges for hot spring waters. While boron concentrations approaching 1000 $\mu\text{g}/\ell$ are somewhat high, thermal wells in New Zealand passing through organic-rich sediments have been shown to contain up to 1200 mg/kg total boron (Ellis and Mahon, 1977).

The total lack of mercury, arsenic and cadmium and low concentrations of zinc is somewhat surprising. Waters from other geothermal areas of comparable temperature and salinity generally have concentrations of these ions upwards of 100 ppm. No explanation for the low concentrations of these ions is apparent at this time.

A minor ion of particular interest in the case of geothermal waters is SiO_2 . Since silica scaling is a common phenomenon in many geothermal areas, the kinetic and equilibrium behavior of forms of SiO_2 has been examined extensively. The most widely accepted model for silica precipitation is that proposed for the Salton Sea Geothermal Field brines.

Minor and Trace Ion Chemistry

Ranges of minor and trace element concentrations in the Glenwood Springs samples are summarized below in Table IV-2.

TABLE IV-2

Minor:	Fluoride	1.9-2.9 mg/l
	Magnesium	15-150 mg/l
	Potassium	150-380 mg/l
	Silica	27-32 mg/l
Trace:	Arsenic	0-1 µg/l
	Boron	760-1000 µg/l
	Cadmium	not detected
	Iron	20-150 µg/l
	Lithium	670-900 µg/l
	Manganese	60-80 µg/l
	Mercury	not detected
	Nitrogen	0.01-0.18 mg/l
	Ortho-phosphate	0.09-0.18 mg/l
	Selenium	not detected
	Zinc	10-30 µg/l

Figure IV-6. Log-Activity Reaction Plot for the Solution of Gypsum and Calcite at Glenwood Springs.

Briefly stated, this model proposes that due to the decrease in temperature and increase in pH (due to the evolution of CO_2) of these solutions as they are brought to the surface, precipitation occurs of fine-grained sulfides which act as nucleation sites for rapidly polymerizing SiO_2 . It is not yet clear whether the Glenwood Springs waters will scale significant amounts of SiO_2 . Although the reported concentrations of SiO_2 are above the solubility limits for all forms of SiO_2 which might precipitate, the kinetics of SiO_2 precipitation tend to be slow. Many forms of treatment have been tried to control silica scaling. These include acidification, addition of base, dilution, magnesium addition, and application of electrical potential. At the present time it is not possible to predict the magnitude of silica scaling at Glenwood Springs. Additional work on scale characterization will be necessary before this can be accomplished.

Several important parameters crucial for design considerations have not yet been investigated in the Glenwood Springs area. These are, most notably, dissolved gas content and oxidation-reduction potential.

Only a single analysis reported any dissolved gases. As previously stated, the equilibration of dissolved CO_2 is a crucial consideration for the prediction of carbonate scaling. Other important gases which may influence the behavior of these waters are H_2S , O_2 , NH_3 , CH_4 and SO_2 . Information regarding the concentrations of these gases would be extremely useful for further geochemical investigations.

Probably the single most important piece of missing information is the oxidation-reduction potential of these waters. Figure IV-7 shows the range of redox potentials for geothermal fluids from several other areas (Baas-Becking et al, 1960). As is apparent from this figure, there is no clear relationship between pH and Eh for geothermal waters, therefore no extrapolation can be made to the Glenwood Springs waters. Since redox potential is the single major controlling factor for corrosion and oxidation, on-site measurement of this parameter is strongly recommended.

Figure IV-7. Known Redox Potentials vs. pH for Geothermal Waters Worldwide.

In addition to the many water chemistry studies at Glenwood Springs, a soil mercury geochemical survey (Klusman and others, 1977) has been conducted in the area specifically to test soil mercury sampling as a geothermal exploration tool. Due to elevated natural heat flow geothermal systems often "leak" anomalous levels of mercury, arsenic and helium which in turn accumulate in the undisturbed surface soils or are dissipated to the atmosphere. The mercury survey at Glenwood Springs only had a minimum of control as the sampling grid covered four square miles at quarter mile (1300 feet) intervals. The soil samples were analyzed for traces of elemental mercury of which the concentrations were then computer filtered to project the calculated residual mercury levels. There are several interference factors (i.e. manganese, organic carbon, soil development, iron, thickness of the A₀ soil horizon, arsenic, pH, and others) which dilute the concentrations of mercury in the soils. When these interference factors are filtered out the resulting mercury residuals show a true mercury anomaly as a function of geothermal activity rather than from secondary influences (Klusman and others, 1977). Figure IV-8 shows the calculated residual mercury concentrations in the soil at Glenwood Springs. The negative mercury anomalies are probably the result of cultural interference due to land improvement, construction and general surface usage. The negative anomaly in the area around the Two Rivers Park site is definitely due to extensive soil reworking, land-fill and stockpiling of solid chemical wastes. Otherwise, this region would probably be within the mercury anomaly resulting from elevated subsurface geothermal activity.

Geophysics. Numerous geophysical surveys have been conducted specifically at Glenwood Springs as have several regional studies which also include the Glenwood Springs region. A state Bouguer gravity map, which includes Glenwood Springs, has been constructed by Behrendt and Bajwa (1974) and a state aeromagnetic map has been constructed by Zeitz and Kirby (1972). A highly sensitive color enhanced thermal infrared remote sensing survey has been flown specifically to locate hot springs within Glenwood Springs (Hansen, 1975). Probably the most valuable geophysical

Figure IV-8. Residual soil mercury map of Glenwood Springs, Colorado (Klusman and others, 1977). Within the hachured area is the region of elevated residual mercury concentrations. Notice the negative anomalies at the Two Rivers Park site and downtown due to cultural interference.

study delineating the geothermal resources at Glenwood Springs were electrical resistivity surveys conducted by the Colorado School of Mines (1977) under contract to the Colorado Geological Survey. The American Association of Petroleum Geologists (1974) constructed several generalized geothermal temperature gradient maps of the United States. One of these maps covers the area around Glenwood Springs.

The most detailed gravity and aeromagnetic data available for the Glenwood Springs region comes from regionalized state maps. The state Bouguer gravity map (Behrendt and Bajwa, 1974) shows the Glenwood Springs area as being within a transitional zone midway between an anomalous gravity high of greater than -230 milligals (White River Uplift 20 miles north) and a region of low gravity (less than -270 milligals) 20 miles to the south in the region of Mt. Sopris. The large-scale state aeromagnetic map of Zeitz and Kirby (1972) is shown in Figure IV-9. This map shows the Glenwood Springs area as lying within a region of rapidly changing magnetics with high's and low's of 4260 to 4000 gammas within three miles of town. The magnetic high northeast of Glenwood Springs is associated with widespread outcropping of the Precambrian basement along No Name and Grizzly creeks. This magnetic anomaly has the highest recorded magnetism within a 20 mile radius of Glenwood Springs. The noticeable magnetic anomalies near Glenwood Springs may be interpreted to result from major lineaments trending to the northwest and northeast as delineated on Figure IV-9 (Geyer, 1980). In the Dotsero area is a slight magnetic nose which is probably the result of extensive basalt to the south of the Colorado and Eagle rivers.

The U.S. Bureau of Reclamation has flown a thermal infrared survey of the Colorado River (Hansen, 1975) from several miles west of Glenwood Springs to the Dotsero area, sixteen miles to the northeast. The purpose of their study was to locate hot springs by use of remote sensing. The survey was flown between 6:00 and 6:30 p.m. on November 20, 1974 and thermal energy was detected on the 8-14 micrometer wavelength region of the spectrum. By taking the black-and-white thermal infrared images and color

Figure IV-9. Aeromagnetic map of the region around Glenwood Springs, Colorado (Zeitz and Kirby, 1972). Geyer (1980) has projected major structural lineaments as defined by magnetics.

enhancing them via a computer, 31 hot springs and vents were located in the immediate Glenwood Springs area. In addition to natural hot springs the color enhanced thermal infrared survey also detected the major overflow and discharges from the Glenwood Hot Springs Lodge and Pool, the sewage treatment plant, and a warm automobile engine block at the local drive-in theater. No attempt was made to quantify the gray scale on the images to measure actual temperatures. In some cases, the temperature extremes were so great that total film saturation occurred, especially due to the hot springs at the Glenwood Hot Springs Lodge and Pool. No attempt was made to field check the zones of hot water discharge but most hot springs recorded in the survey have been previously documented or are included in documented groups of springs.

The Colorado School of Mines conducted both reconnaissance and detailed electrical resistivity surveys at Glenwood Springs under contract to the Colorado Geological Survey (Colorado School of Mines, 1977). In both resistivity surveys an electrical current is induced into the ground and apparent resistivities (ohm-meters) are recorded by receiver electrodes. Electrical resistivity is an inverse function of conductivity which can be the result of fluid salinity. Therefore, low resistivity generally indicates an area of highly saline fluids in the subsurface which can be a function of geothermal resources. At Glenwood Springs a reconnaissance dipole-bipole (roving bipole) survey was conducted over an 80 square mile region centering on the town. The results show high resistivity background measurements of 20 to 40 ohm-meters to the north of the Colorado River and west of the Roaring Fork River. This reconnaissance survey indicates a low resistivity anomaly of 2.0 to 2.5 ohm-meters in the Lookout Mountain vicinity 1.5 miles to the east of Glenwood Springs. Because of complex terrain and the possibility that apparent resistivity can be controlled by terrain (measurements taken near Lookout Mountain were 1600 feet higher in elevation than those at Glenwood Springs), this interpretation must be considered tentative and highly suspect.

The most valuable geophysical data on the geothermal resources at Glenwood Springs is derived from the detailed dipole-dipole electrical resistivity survey. Whereas a roving bipole survey can measure to depths greater than one mile, a dipole-dipole survey records closely spaced data points with penetration depths from 200-400 feet. Resistivity readings were recorded at 62 dipole-dipole stations throughout Glenwood Springs and indicate background resistivity levels of greater than 80 to 100 ohm-meters. As shown on Figure IV-10 two anomalous resistivity lows were measured by the Colorado School of Mines (1977) in the vicinity of the Glenwood Hot Springs Lodge and Pool, and surrounding Gamba Hot Springs and the Two Rivers Park site. The survey shown in Figure IV-10 was conducted with an electrode separation of 800 feet and therefore the depth of penetration was approximately 400 feet. It should be noted that the Colorado School of Mines (1977) also conducted an identical dipole-dipole survey with a penetration depth of 200 feet but the results are so similar it is not necessary to review the shallower survey. Based upon these surveys there are two apparent areas of geothermal activity at Glenwood Springs which are also supported by the location of hot springs (Figure IV-1). From Figure IV-10 it is seen that the eastern resistivity anomaly is slightly less conductive (low of 3.25 ohm-meters) than to the west (9.69 ohm-meters). This may be indicative of slightly greater geothermal activity such as higher temperatures, greater fluid volumes, or more extensive reservoir fracturing. However, since both anomalies are similar in intensity and areal extent it is probable that subsurface conditions are also similar.

The American Association of Petroleum Geologists has constructed several geothermal temperature gradient maps encompassing most of the United States. These maps are a composite of available down-hole temperature data from oil and gas wells. Figure IV-11 shows the calculated temperature gradients for the Glenwood Springs area (American Association of Petroleum Geologists, 1974). There is no data in the immediate Glenwood Springs area as the closest control point is 10.5 miles southwest of town and therefore accuracy and validity of this survey are questionable.

Figure IV-10. Dipole-dipole electrical resistivity survey at Glenwood Springs, Colorado (Colorado School of Mines, 1977). Notice the relationship of the eastern anomaly to the Glenwood Hot Springs Lodge and Pool, and the western anomaly to the Two Rivers Park site.

Figure IV-11. Geothermal temperature gradient map of the region around Glenwood Springs, Colorado (A.A.P.G., 1974). Contour intervals are at 2.0 F/100 feet and are based upon data points from existing oil and gas tests (represented by +). 1 inch = 8 miles

The average geothermal gradient for the western United States is about 2.8°F/100 feet so an interpolated temperature gradient of 1.75°F/100 feet at Glenwood Springs is considerably below average. At this temperature gradient meteoric waters would have to circulate to depths greater than 4500 feet in order to achieve temperatures near 125°F which is the surface temperature of the hot springs. Natural geothermal heat flow in the Glenwood Springs area is not anomalously elevated on a regional basis and therefore more detailed temperature gradient drilling must be conducted.

Previous Geothermal Resource Models. The geothermal resources at Glenwood Springs have been investigated and studied by numerous people and several have constructed resource models and made projections of the reservoir characteristics. Several private consultants and small companies such as J.S. Rinehart (1980), C. Millison (1980), and Chaffee Geothermal, Ltd. (Dick, 1978) have made brief studies. The U.S. Geological Survey (Renner and others, 1975; and Sammel, 1978) and the Colorado Geological Survey (Barrett and Pearl, 1978; and Pearl, 1979) have also proposed preliminary geothermal models and characteristics. Some of these projections are based upon very meticulous research and empirical understanding while others are highly questionable and appear to have no geologic foundation.

Clark Millison (1980) has been a consulting geologist in the Glenwood Springs area for many years and has proposed a questionable geothermal model. He believes that a fault running beneath the Colorado River and trending to the northeast intersects with a northwest trending fault just immediately west of the Roaring Fork River. A fracture reservoir within the Leadville Limestone is then created and traps meteoric waters which are heated by a buried intrusive. The geothermal fluids may be circulating due to natural convection and discharge at the Yampah Hot Springs. Millison also projects that the hot circulating fluids encounter buried evaporite deposits and in turn adsorb sodium chloride, thusly, accounting for the high salinities (17,000 to 20,000

mb/1) of the hot springs. Millison has projected the geothermal reservoir at Glenwood Springs to extend for 2.5 miles along the Colorado River and to be about 1.25 miles wide. He also believes the reservoir to be 1150 feet thick with a porosity of 20%.

The fault zones to which Millison refers could possibly be the Storm King thrust fault (east-west) and a minor northwest trending fault (Figure IV-2). There is no surface evidence of a fault zone trending northeast along the Colorado River. A field check of this area will show that the sedimentary beds on the north and south sides of the river are in apparent alignment with no noticeable offset. If a fault were present it would be of extremely low magnitude. Though there are numerous lava flows in the Glenwood Springs area it is questionable that these are contributing latent heat to the geothermal resources, and there is no evidence to support a buried intrusive (see Figures IV-2 and IV-9). Millison's theory of geothermal fluid interaction with the buried evaporites is probably correct. Electrical resistivity surveys (Colorado School of Mines, 1977) indicate that the areal extent of the local geothermal reservoir is less than that projected by Millison and if geothermal fluids are trapped within the Leadville Limestone the reservoir thickness is considerably less than 1150 feet.

Another consulting geologist, J. S. Rinehart (1980), suggests that two sources of water are contributing to the hot springs in the area. A relatively small source of fluids is circulated to great depths where it is heated and then convected back to the surface. Near the surface these extremely hot geothermal fluids encounter, and thusly heat, a much greater volume of cold groundwaters. Rinehart projects that the Colorado River is directly channeling the huge quantities of cold water (3000 gpm) which mix with the geothermal waters as they ascend permeable fault zones. It is a known fact that 95% of all geothermal systems have some degree of cold groundwater mixing and interference, however, it is highly questionable that the Colorado River is directly contributing massive quantities of cold waters to the hot springs at Glenwood Springs.

If this were the case the geothermal fluids would have to be of extremely high temperature to equilibrate with the large cold water influx.

The U.S.G.S. has undertaken an extensive geothermal resource appraisal of the entire western United States and consequently have published Circular 726 (Renner and others, 1975) and Circular 790 (Sammel, 1978). In both of these resource appraisals a brief review of the hot springs in the western United States is undertaken, but the major deterrent to these assessments is that referencing of source material is inadequate and a relative validity rating for the various resource projections is nonexistent. Circular 726 was published prior to the extensive geochemical modeling by Barrett and Pearl (1978) and therefore did not have the advantage of their detailed work. Circular 726 projects the areal extent of the geothermal reservoir to be about 0.6 square miles with a thickness of 4900 feet. Subsurface temperatures are projected to be from 135° to 375°F with a "best guess" of 285°F. There are no indications of reservoir temperatures over 200°F and definitely not as great as 375°F, and a projected reservoir thickness of 4900 feet is utterly absurd. The data published in Circular 790 is based upon the work by Barrett and Pearl (1978) but the lack of projected resource characteristics in Circular 790 makes this assessment virtually worthless.

The Colorado Geological Survey (Pearl, 1979) projects that the geothermal resources at Glenwood Springs are the result of deeply circulating groundwaters migrating up-dip within the Leadville Limestone. The heat source is merely deep circulation in association with the natural geothermal gradient and the Colorado Geological Survey believes fluid recharge may be to the southwest of Glenwood Springs. It is also feasible that the geothermal resource may be fault controlled due to extensive fracturing as a result of the White River Uplift. If the resource is fault controlled then fluid recharge may be to the north of town. At depth, the geothermal fluids encounter the evaporite deposits of the Maroon Formation (sic) or the Eagle Valley Evaporite, which accounts for the high sulfate content of the hot springs. This model also projects

reservoir temperatures to be similar to the surface temperatures of the hot springs (125°F). These subsurface temperatures are based on the excellent correlation between hot spring temperatures and several of the geochemical models, as well as the relationship of reservoir temperatures with high spring discharge rates.

Dick (1978) has worked with the Glenwood Springs geothermal system for several years and makes several reservoir projections based upon existing geological information, extensive field work at Glenwood Springs and empirical geothermal experience. He projects the reservoir to be confined to the Leadville Limestone with a thickness of 250 feet, at a depth beneath Glenwood Springs of 600 feet. The areal extent may be two square miles with a reservoir temperature of 149°F. At these projected temperatures, thicknesses and areal extent Dick projects that 112 megawatts (thermal) could be used for space heating by Glenwood Springs for approximately 40 years. These projections carry a validity of 30% though it is not clear what this means or is based upon.

Geothermal Resources at Glenwood Springs. By utilizing all geological and geochemical data compiled via this study, a detailed reservoir model (with associated resource characteristics) is projected herein. This model is the most complete review of the geothermal resources at Glenwood Springs that has been done to date. So as to yield greater credibility to reservoir characteristics, all resource projections herein are given a validity rating based upon the potential accuracy of that specific projection. This rating system is as follows:

Validity Rating

- 3 - Very confident in the accuracy of the projected data, greater than 50% validity.
- 2 - Sufficient data to indicate the possibility of these characteristics, approximately 50% validity.
- 1 - Some data to indicate these characteristics; a "best guess" at the accuracy of the projection.

As in the model projected by the Colorado Geological Survey (Pearl, 1979) the geothermal fluids are probably ascending the highly porous, and steeply dipping Leadville Limestone. There are no faults in the area that apparently would be deep-seated enough to allow deep circulation of hot fluids. The geothermal fluids could possibly be ascending the Storm King thrust fault from a heat source to the northeast, but due to its extremely low angle of dip the fault may not penetrate to a sufficient depth to obtain the required heat. As the geothermal waters ascend through the Leadville Limestone they may encounter a highly fractured zone near the surface where the Storm King thrust fault intersects with several other northwest and northeast trending faults (Figure IV-2). This fractured zone may be an area of shallow groundwater mixing similar to that projected by Rinehart (1980) but definitely not in as high of quantities as his projections. A mixing model, such as projected herein, may indicate that hotter fluids could be encountered down-dip in the Leadville Limestone, prior to groundwater interference in the fractured fault zones. The localities of the existing hot springs imply definite controls by the Storm King and other local faults in the area but geophysical surveys limit potential geothermal activity to the area immediately adjacent to the Storm King thrust fault. From the resource model projected herein the hottest geothermal reservoir is probably within the Leadville Limestone southwest of the Storm King thrust fault. Due to the angle of dip in the Leadville Limestone a geothermal well could encounter up to 300 feet of reservoir thickness. The validity resting on this model is a "2".

The areal extent of the geothermal reservoir at Glenwood Springs can most accurately be defined by the localities of hot spring occurrences (Figure IV-1) and the anomalous low resistivities of the dipole-dipole survey (Figure IV-10). The areal extent within the 20 ohm-meter contours of Figure IV-10 only represent 0.3 square miles, however, hot springs discharge for several hundred yards to the northeast of town and for two miles to the west, as shown by thermal infrared photography (Hansen, 1975). The overall geothermal resources at Glenwood Springs may include

an area of 1.5 to 2.0 square miles with the main reservoir limited to less than 0.5 square miles as defined in Figure IV-10 (validity rating: 3).

From the geochemical modeling by the Colorado Geological Survey (Barrett and Peark, 1978), and supported by calculations of Fitzpatrick (1980), the subsurface reservoir temperature may be from 140° to 180°F (validity rating: 3). At an unknown depth the reservoir temperature probably does approach 180°F but not necessarily immediately beneath Glenwood Springs. This higher reservoir temperature is not only supported by Fitzpatrick's detailed silica calculations but also by the Colorado Geological Survey's estimated mixing with up to 40% cold groundwater. If the hotter geothermal fluids are ascending the Leadville Limestone it is feasible that continued drilling through the Leadville, and into the Chaffee Formation, "might" result in cooler temperatures. Deeper drilling does not necessarily mean hotter temperatures.

Assuming the geothermal fluids are migrating up the Leadville Limestone, then a geothermal well drilled to the southwest of Interstate 70 should encounter elevated reservoir temperatures. Due to the steeply dipping strata, as projected by Bass and Northrop (1963) and shown in Figure IV-3, a well drilled near the Colorado River should intersect the Leadville Limestone at a depth near 500 feet (validity rating: 2). Due to the high angle of dip the total well depth required to completely penetrate the Leadville may be up to 800 feet prior to encountering the underlying Chaffee Formation. The further southwest a well is drilled the greater the depth to the top of the Leadville Limestone, but consequently a greater reservoir temperature is feasible. At a natural geothermal temperature gradient of 1.75°F/100 feet, waters must percolate to a depth of greater than 7700 feet to naturally achieve 180°F temperatures, and then begin ascending up-dip. However, it is believed reservoir temperatures of 180°F can be encountered at much shallower depths than 7000 feet. Due to the high discharge rates of the hot springs large flows of warm water (100° to 125°F) may be encountered at shallow depths

prior to encountering the Leadville Limestone. During well design and drilling, and especially prior to setting of surface casing, extreme caution must be undertaken to control and shut-in any unanticipated flows.

The Leadville Limestone is known to be a very porous and cavernous formation with exceptionally good groundwater movement. Hot springs flowing from the Leadville Limestone generally have good flow rates ranging up to 150 gpm with a discharge of greater than 2200 gpm from the Yampah Hot Spring. Providing proper precautions are taken to prevent scaling in the wellbore, it is anticipated that production rates of 1000 gpm, or greater, may be feasible from each of several geothermal wells drilled into the Leadville Limestone (validity rating: 1).

A summary of the various geothermal resource characteristics (with the associated validity rating) as projected herein includes:

Formation:	Leadville Limestone (2)
Reservoir thickness:	300 feet [90 m] (2)
Areal extent:	0.5 to 2.0 square miles (3)
Subsurface temperature:	140° to 180°F [60°-82°C] (3)
Depth to top of reservoir:	500 feet [150 m] (2)
Flow rate per well:	≥ 1000 gpm [3800 lpm] (1)

Resource Assessment Conclusions. From the resource data and information compiled herein it is apparent that there are two specific anomalous areas of geothermal activity at Glenwood Springs. The eastern area, as defined by hot springs and electrical resistivity surveys, centers around the group of hot springs just east of the Glenwood Hot Springs Lodge and Pool. The western anomaly is centered around the Hobo Pool and Gamba Hot Springs (Figures IV-1 and IV-10). It may not be practical to further develop the geothermal resources within the eastern target area due to its proximity to the very profitable resort enterprise at the Glenwood Hot Springs Lodge and Pool, Inc. It has also been reported that the Glenwood Hot Springs Lodge and Pool has bought the water-rights (geothermal-rights...?) to several of the hot springs along the southern

bank of the Colorado River within the eastern target area. Therefore, from the data presented in this report the best location for future geothermal development will be within the western geothermal anomaly.

B. Proposed Geothermal Exploration Program

The existing geothermal resource data is very adequate to model the general characteristics of the geothermal system at Glenwood Springs but it is insufficient to base a future drilling program upon. More detailed data and information is mandatory to target a specific drilling site for a future exploration well to ultimately be used for a municipal geothermal heating district. Based on the existing geothermal resource data, Chaffee Geothermal proposes that three exploration surveys be conducted to further delineate a specific drilling target:

detailed gravity measurements
hammer seismic
detailed geologic mapping

A fourth optional survey may be conducted depending upon the results and interpretations of the above. The drilling of 1 or 2 slim hole mineral cores would further characterize any existing fault and/or fracture zones and thus aid in the final selection of a drill site. The mineral cores would be drilled at an angle toward the suspected fault/fracture zone, to minimize the total footage required.

A close-grid, surface gravity survey should be conducted in the immediate Glenwood Springs area to further detail the geologic structure of the vicinity. This survey will aid in delineation of faults and fractures as well as in modeling the subsurface geology. A two man crew can conduct this survey within one week using a portable gravimeter to take surface readings at the 37 stations outlined in Figure IV-12. A second week will be required for data reduction and interpretation. There are no permitting or environmental impact requirements for a gravity survey as measurements have absolutely no impact on the site.

Not shown on map: G1, G2, G6, G7, G8, G10, G11, G12, & G14

Figure IV-12. Locations of 37 surface gravity measuring stations at Glenwood Springs, Colorado. The two geothermal target areas are also outlined.

It may be advisable to conduct the gravity survey at Glenwood Springs between midnight and six a.m. due to cultural noise and interference. A gravimeter is extremely sensitive to vibrations at the earth's surface and therefore prolonged vehicle movements, trains and general cultural disturbances can interfere with data readings. Since this survey will be conducted in the immediate proximity of the town of Glenwood Springs it is felt that less background interference will occur during the nighttime hours.

It was originally thought that a magnetotelluric/Schlumberger electrical resistivity depth sounding survey may lend evidence to the depths of the geothermal fluids. ⁽¹¹⁻¹²⁾ Magnetotelluric/Schlumberger surveys are conducted by inducing an electrical current (DC) into the earth and measuring the strata's resistivity as a function of depth. Those zones with low resistivity (high conductivity) may be indicative of highly saline geothermal fluids. However, further investigations show that physical logistics and cultural interference make this approach impractical. An electrical survey to evaluate the subsurface to a depth of 1000 ft would require a 2000 ft separation of electrodes. In the Glenwood Springs area the only acceptable location for this would be along the freeway median. Even using this area, the data would have interference from overpasses and steel railroad tracks. Therefore, it seems that further electrical resistivity work would be of little or no value.

After interpretation of the gravity data a hammer seismic survey should be conducted. In these seismic surveys an induced shock is sent into the ground and receivers record the transit time for the sound waves to return to the surface. The speed of sound in subsurface formations is dependent upon the porosity, permeability, and types of fluids and compaction present. The more compacted the formation the less readily it will transmit the soundwaves and will instead reflect them back. These reflected waves are received by the equipment on the surface and travel times calculated. The purpose of conducting this survey in the immediate area is to obtain the depth to bedrock. This information will be valuable in planning the drilling and casing programs.

Figure IV-13. Locations of the three previously proposed magnetotelluric/Schlumberger electrical resistivity depth sounding stations as they relate to the projected geothermal resources at Glenwood Springs, Colorado.

Also important in the exploration program is the detailed geologic mapping of the target areas (Figure IV-13⁴). This work is to confirm studies done in the past and to concentrate on the Hot Springs area. This mapping could reveal any surface expressions of faults and/or fractures in the region and thus aid in the location of the exploration well. It would also be significant to establish the contact between the unconsolidated surface gravels and the Leadville Limestone. Again this would be helpful in planning the drilling and casing programs as well as selecting a final drilling location.

Interpretation of the data obtained from these three surveys could indicate the need for a fourth technique to select the specific drilling site. If the above surveys indicate the existence of a fault and/or fracture system the drilling of one or two (NX-BX) slim hole mineral cores may be warranted. The purpose of this is to ascertain the existence, angle, and permeabilities of these fault zones. This would further delineate their influence on the ascending geothermal fluids, and help to pinpoint the exploration drilling site.

Several problems could be encountered with this technique which need to be discussed. First the occurrence of both geothermal and formation fluids could cause difficulties in drilling and plugging these core holes. This would be dependent upon the porosities and permeabilities of the formation encountered and the faults or fractures themselves. Also the angle and dip direction of the fault itself would determine the depth to penetration. The steeper the dip of the fault the longer the mineral cores will be to intersect it. Also the actual dip direction of the fault must be accurately established to avoid drilling unnecessary footage in the mineral cores.

The overall value of this survey warrants the risk and expenditure because it will give firsthand knowledge of the faults and subsurface geology. Also, the knowledge of what will be encountered in the first several hundred feet of drilling is extremely valuable for future well and casing design. Decision to drill the angled mineral core slim holes

Figure IV-14. Geothermal target areas for detailed geologic mapping. Exploration is limited to the western geothermal target area only.

would be based on the validity attributed to the other geologic data describing the features of the proposed drill site.

As an alternative to the angled mineral cores, a slim hole drilled to the Leadville Limestone (the suspected reservoir formation) should also be considered. This would establish the stratigraphy in the target drilling area for the production well and more importantly, permit the determination of production fluid temperatures. Of course, this assumes that the slim hole intersects the geothermal resource. An additional benefit to the slim hole would be its use as a monitor well during flow testing of a future production well. This would provide data which may be useful in determining the separation distance needed between production and reinjection, if disposal in the Leadville is selected.

Upon completion of these surveys a reasonably precise target can be projected for the drilling of an exploration test well. Combined interpretation and modeling from the pre-existing dipole-dipole electrical resistivity survey (Fig. IV-10) and the new gravity, hammer seismic, and mineral core surveys will all aid in defining the areal extent of the Glenwood Springs geothermal resource.

Though a geothermal exploration program will warrant a maximum expenditure of less than \$50,000 over a five to six month period, it will give mandatory information on the specific site location for drilling a full scale exploration well. It is economically of greater feasibility to invest in an exploration program rather than drilling a \$100,000 to \$200,000 "dry hole".

C. Drilling and Reservoir Engineering

The best location for exploratory geothermal drilling in Glenwood Springs is within the limits of the western geothermal anomaly as shown in Figure IV-15. The city owns the acreage at the Two Rivers Park site and therefore this location has been selected as the proposed drilling site. As shown in Figure IV-3 a well drilled at this location would

Figure IV-15. Anomalous geothermal resource areas in Glenwood Springs, Colorado. The dashed lines outline geophysical target areas. Also shown are the locations of hot springs with approximate flow rates represented by:

> 150 gpm = ● , 50 - 150 gpm = ○ , < 50 gpm = *

have a total depth of 800 feet if it was drilled through the projected geothermal reservoir in the Leadville Limestone. A well drilled on this site would be cased to the top of the production zone (500 foot depth) and produce from the entire thickness of the Leadville Limestone. It is anticipated the well may produce at rates of 1000 gpm with resource temperatures greater than 140°F.

Well Design and Drilling Program. Due to anticipated high production rates of 1000 gpm or greater the exploratory well is designed with a large production bore to not restrict artesian flow. Also, the bore is large enough to accommodate downhole impellers or a submersible pump if the need arises. A well profile is shown in Figure IV-16.

The first exploration well for this project is herein numbered "GS 9-1" because it is in Glenwood Springs and is the first geothermal well drilled within Section 9 (T.6S., R.89W.). As shown in Figure IV-16, a 20 inch conductor pipe (grade: F-25, weight: 90 pounds/foot) will be set to a depth of 40 feet or through the surface gravels and river boulders and into the shales of the Belden Formation. Then 13-3/8 inch surface casing (grade: F-25, weight: 48 pounds/foot) will be set into the Belden Formation to a depth of approximately 150 feet. It is very important that the surface casing be set prior to encountering any large volume flow rates because blowout prevention equipment will be placed on this casing during final drilling. Prior to beginning the well, all existing wells in the immediate vicinity will be checked to approximate the true depths to flowing aquifers. It is very feasible that the surface casing could be set as shallow as 100 feet if the shales of the Belden Formation prove sufficiently competent to hold a shallow surface casing.

Production casing of 9-5/8 inches (grade: H-40, weight: 32.3 pounds/foot) will then be run from the surface to a depth of 505 feet and anchored into the upper portion of the Leadville Limestone. Since the Leadville is the anticipated production horizon, it will be completed through its total thickness with an 8-3/4 inch open hole. This 8-3/4 inch bore will be drilled until it penetrates the upper limestone sequences

FIGURE IV-16: GS 9-1 Well Profile

in the underlying Chaffee Formation. This will give a proposed total depth for GS 9-1 of near 805 feet. Should the Leadville Limestone not prove sufficiently competent to maintain an open hole through the production zone, then the well can be re-entered, cleaned, and a 7 inch slotted liner can be hung from the 500 level of the production casing and through the entire producing aquifer.

The general procedure for drilling a geothermal well to the specifications as described herein is as follows:

1. Level a drilling pad of approximately 100' by 50' and excavate a 10' by 20' mud pit (8' deep). Also excavate a drilling cellar of 5' by 5' (3' deep) and a flow line to the Colorado River (pending Colorado Health Department and U.S. Bureau of Reclamation approval) or to a settling pond (also to be excavated if needed). A plan of the drilling site is shown in Figure IV-17. The total area to be impacted is less than one-half acre.
2. Cement line the drilling cellar and install drains. Cover the drilling cellar with steel grating.
3. Move in cable-tool drilling rig and rig-up over the drilling cellar.
4. Drill a 26" bore to a depth of 40' or through the surface gravels and river boulders.
5. Set and cement the 20" conductor pipe to a depth of 40'. Use ready-mix and wait on the cement to set for 8 hours.
6. Rig-down and move off cable-tool rig.
7. Move in and rig-up rotary drilling rig. Begin mixing drilling mud.
8. Spud-in and begin drilling a 6-3/4" pilot bore to 150' or to whatever depth the surface casing is to be set.
9. Ream hole to 150' with a 6-3/4" pilot and 12 1/4" cutter bit.
Ream hole to 150' with 12 1/4" pilot and 17 1/2" cutter bit.
10. Run 13-3/8" casing to 150'. Thread guide shoe on bottom threads and place an insert fill-up valve at the first collar. Weld a centralizer in the middle of the first joint (depth 135') and place centralizers at the bottom collar (depth 120') and the top collar (depth 40').

Figure IV-17. Proposed plan-view of the geothermal drilling site at Glenwood Springs, Colorado.

11. Set and cement 150' of 13-3/8" casing with approximately 125 sacks, or until adequate returns are obtained at the surface, of Class "G" cement with 2% CaCl additive. If returns are not obtained at the surface then grout annulus from the surface with Class "G" cement minus CaCl (if possible). Wait on the cement to set for 12 hours.
12. Pressurize casing to 100 psi and hold for 10 minutes. This will check the threaded connections on the collars.
13. Re-enter the hole to the top of the cement (about 120' or at the insert fill-up valve) and drill-out the insert fill-up valve, cement, guide shoe and 5' of formation with the 12 1/4" bit.
14. Test the casing seat with 100 psi for one hour. Observe the pressure gauge for leak off. If pressure bleeds off rig-up to squeeze.
 - Pick up RTTS packer and go to 145' and set packer. Pump 20 sacks of Class "G" cement plus 2% CaCl and squeeze casing shoe. Do not exceed 250 psi pressure during squeeze. Keep the bore pressurized and wait on the cement to set for 12 hours.
15. Retrieve RTTS packer and re-enter the hole with the 12 1/4" bit and drill-out the squeezed cement. Retest casing seat to 100 psi. Resqueeze if pressure bleeds off.
16. Thread (weld) casinghead flange on to the 13-3/8" surface casing and nipple-up drilling stack (Figure IV-18).
17. Enter bore with 6-3/4" pilot bit and begin drilling to 505', or into the Leadville Limestone. This drilling will take place with normal weight mud (9-10 pounds/gallon) even if large flows are encountered. Drilling will continue through flowing zones with normal weight mud which will lift cuttings up the bore to be flushed out by the producing formation.
 - Should mud returns not occur at the surface then the blowout preventer (pipe rams) will be set and lost circulation materials, plus mica flakes, will be pumped into the lost circulation zone until shut-in pressures increase. Then the blowout preventer (BOP) will be opened and mud returns will occur at the surface.
18. Trip out of the hole with the 6-3/4" pilot bit and reamout the bore to a depth of 505' with a 6-3/4" pilot and 12 1/4" cutter bit.
19. If large flows are encountered while the 12 1/4" bit is in the hole, shut pipe rams (BOP) and begin mixing 14-16 pound/gallon mud (barite additive) or whatever weight is required to kill the flows. When the mud is up to weight open the pipe rams (BOP) and circulate and until flow is killed.

FIGURE IV-18: GS 9-1 Drilling Stack

20. Trip out of hole and tear down the drilling stack.
21. Run 9-5/8" production casing to the bottom of the hole. An insert fill-up valve will be placed at the first collar and a guide shoe threaded to the bottom of the casing. Centralizers will be placed on the bottom joint (depth 490') and then at 440', 320', 200' and 80' of depth.
22. Cement the production casing with 200 sacks, or until returns occur at the surface, of Class "G" cement plus 2% CaCl (3% CaCl if major flows were encountered). Cement weight must be 16 pounds/gallon (depending on pressure of producing zones) and pumped very slowly at 2 barrels/minute. If returns are not obtained at the surface then grout annulus from the surface. No flushing plug of fresh water should be run ahead of the cement. Wait on the cement to set for 12 hours.
23. Repeat steps 12 through 15.
24. Cut off casinghead flange from 13-3/8" surface casing and thread on (weld) permanent casinghead flange to 9-5/8" production casing. Nipple-up master valve, banjo box and rotating head.
25. Enter bore with 8-3/4" bit and begin drilling in the Leadville Limestone by using both pumped and produced water as the drilling fluid. Drill through the Leadville or to a depth of approximately 805'. Flow rates during drilling can be measured at the blooie line via an orifice plate and manometer tube.
26. Trip-out of well and shut-in master valve while retrieving 8-3/4" bit through rotating head.
27. Reclose rotating head and open master valve and allow the production zone to produce and clean itself by flowing through the blooie line.
28. Shut-in well, rig-down and move all rotary and support equipment off site.
29. Conduct 24 hour and long term reservoir tests by flowing production zone through banjo box and blooie line.
30. After reservoir tests, shut-in master valve and unbolt banjo box and rotating head and dismantle mud line and kill line. Bolt on second master valve (if desired for safety) and weld neck flange and connect pipeline to wellhead (Figure IV-19).

A projected chronologic log of drilling times is as follows:

Day 1: (12 hours) Move in and rig-up cable-tool rig. Begin drilling 26" bore.

FIGURE IV-19: GS 9-1 Wellhead Completion Assembly

Day 2: (12 hours) Drill 26" bore.

Day 3: (12 hours) Drill 26" bore.

Day 4: (12 hours) Drill 26" bore.

Day 5: (12 hours) Set and cement 20" conductor pipe to 40'.
Rig-down and move off cable-tool rig.

Day 6: (all days are 24 hours from here on) Move in and rig-up rotary rig. Drill 6-3/4" pilot bore to 150'.

Day 7: Ream hole to 17 1/2".

Day 8: Set and cement 150' of 13-3/8" surface casing. Nipple-up drilling stack.

Day 9: Drill 6-3/4" pilot bore to 505'.

Day 10: Ream bore to 12 1/4".

Day 11: Ream bore to 12 1/4". Mud-up and kill flows.

Day 12: Set and cement 9-5/7" production casing. Nipple-up drilling stack.

Day 13: Begin drilling 8-3/4" bore in the Leadville Limestone.

Day 14: Complete 8-3/4" bore in Leadville Limestone to a depth of 806'. Rig-down and move off site.

Well Costs. Contained herein are the itemized well costs to drill a geothermal exploration well at Glenwood Springs, Colorado. These costs are based on the well specifications and drilling procedures outlined in this report.

1) Site preparation	
Excavation of settling ponds included.	\$10,000
2) Mobilization	5,000
3) Drilling time	
Cable-tool, \$80/hour, 5 days (12 hours @	4,800
Rotary, \$175/hour, 9 days (24 hours @)	<u>37,800</u>
	\$42,600

4) Casing	
20" conductor, \$30/foot	1,200
13-3/8" surface, \$20/foot	3,000
9-5/8" production, \$13/foot	<u>6,565</u>
	\$10,765
5) Cement	
400 sacks Class "G" + 2% CaCl	2,512
Pump charges	1,350
Trip charges	320
Service charges	2,000
Valves, plugs, miscellaneous	<u>1,500</u>
	\$7,682
6) Mud	
150 sacks Gel	900
800 sacks Barite	4,800
50 sacks LCM and mica	<u>300</u>
	\$6,000
7) Wellhead	
Master valve - 10"	\$8,000
Safety valve (if needed)	2,000
Weld neck flange	1,500
Misc. fittings, valves and flanges	<u>3,500</u>
	\$15,000
8) Wireline services	
Flat rate	3,000
Logging surveys	7,000
Mileage	<u>180</u>
	\$10,180
9) Contingencies	
25% of well costs	\$26,807

Site preparation	\$10,000
Mobilization	5,000
Drilling	42,600
Casing	10,765
Cement	7,682
Mud	6,000
Wellhead	15,000
Wireline	<u>10,180</u>
	\$107,227
Contingencies	<u>26,807</u>
TOTAL WELL COSTS:	\$134,034

It may prove more economical to initially drill a much smaller exploration well with a conductor pipe of 10-3/4", a surface casing of 8-5/8" and a production casing of 4 1/2". This would cut costs down to approximately \$108,000 but flow rates may prove insufficient to supply the entire community. However, once construction has begun on a municipal heating district, and it is known what initial production demands are required, it may then prove most economical to drill a full bore (9-5/8" production) geothermal well. This rationale lowers the financial risk of the first exploration well and would also decrease the debt service on a well which initially is larger than is needed.

Reservoir Engineering. The purpose of conducting reservoir testing on the first exploration well (and subsequent production and disposal wells) is to primarily determine:

Optimum reservoir production rates
Impact to surrounding wells and springs (both hot and cold)
Reservoir longevity

Though there are no geothermal wells in Glenwood Springs to be used as observation wells during reservoir testing, there are numerous hot spring vents which can be monitored. Any water wells within a 1000 foot radius of the test well will also be monitored.

Wellhead equipment on the test well (GS 9-1) will be set-up as shown in Figure IV-20. A 10 inch weld neck flange will be bolted onto the master valve and an 8 inch flow line (bloop line) will be welded/threaded to the flange. A pressure transducer will be tapped into the line upstream from an 8 inch gate valve which will be used to regulate flow. At the discharge end of the flow line will be placed interchangeable orifice plates of various sizes which will create uniform back-pressures on the flow that can be monitored by a manometer.

Select cold water wells within 1000 feet of GS 9-1 will have pressure transducers attached to them and during testing it will be requested that these wells remain static and shut-in. Knowledge as to the depths

Figure IV-20. Sketch of test well GS 9-1 showing pressure monitoring system and wellhead equipment for controlling and measuring flow.

of these wells is important to determine which aquifers are impacted (if any) by high production rates from GS 9-1. The only adjudicated water well within this region is the Simillian Well located approximately 990 feet southeast of the proposed GS 9-1 drilling site. This well is only 40 feet deep and produces at 15 gpm. The best reservoir data will be derived by monitoring flow rates of several hot springs in the vicinity. Recommended hot springs to be monitored (Figure IV-15) include:

Glen 76/Glen 78 (combined)
Gamba
Yampah (Glenwood Hot Spring Lodge and Pool, Inc.)
CGS-B

At each hot spring vent a 90° V-notch weir or Parshall flume will be installed. During flow testing water levels and flow rates at each hot spring will be monitored to determine which hot springs (if any) are impacted by production from the test well.

Prior to long term flow testing, "pulse" tests will be run on the test well to determine the optimum flow rate for the 24-hour constant-discharge test. If initial unrestricted flow rates of GS 9-1 are in the order of 800 to 1000 gpm then one-hour pulses of 300, 500, 700 and 1000 gpm should be flowed while monitoring pressure and flow fluctuations on observation wells and springs. Between each pulse a one-hour recovery should be allotted so as to minimize influences between tests.

After determining the maximum flow rate which will hold constant for 24-hours a constant-discharge test will be conducted. To conduct the 24-hour constant-discharge test, well GS 9-1 will be opened to the pre-determined flow rate and all observation wells and springs will have their pressure/flow rates recorded simultaneously. Readings should be recorded at the following intervals: 5, 10, 15, 20, 30 and 45 seconds from the start; 1 minute, 90 seconds, 2 minutes, 150 seconds and continue at 30 second intervals to 10 minutes; 1 minute intervals to 20 minutes; 10 minute intervals to 1 hour; and every 2 hours until the termination

of the 24-hour constant-discharge test. At 24-hours the test well will be shut-in and pressure/flow rates will be recorded at the same time intervals as during flow, or until the observation wells undergo 100% recovery.

After flow testing and the recovery period, reservoir data is recorded, compiled and reduced to a workable format. The data will be plotted and analyzed using several analytical methods to obtain estimates of reservoir transmissivity and storage coefficients (Table IV-4). This data, combined with geological and hydrological modeling of the Glenwood Springs geothermal resource, will allow calculated projections of reservoir production rates, pressure fluctuations and longevity.

D. ReInjection of Geothermal Fluids

After geothermal fluids have been put to beneficial use in a municipal heating district at Glenwood Springs, they must be disposed of or recirculated. When a large volume of fluids are being utilized, in the order of 500 to 1000 gallons per minute (gpm), the only feasible disposal methods are direct surface discharge or reinjection. Due to government control of high salinity discharge into the Colorado River, and Colorado geothermal and water law regarding adjudication of consumptive water-rights, it is impractical to use surface discharge as a disposal method of geothermal fluids at Glenwood Springs.

Reinjection is the most viable method for disposal of spent geothermal fluids at Glenwood Springs. The primary purposes of reinjection are:

- disposal of utilized geothermal fluids
- reduce the bureaucratic "red tape" of consumptive water-rights
- increase reservoir longevity by maintaining formation pressures
- improve recoverable heat-reserves
- prevent subsidence

Table IV-3

Recommended analytical methods to estimate geothermal reservoir characteristics at Glenwood Springs, Colorado.
(Hydrosciences, Inc., 1979)

Four different analytical methods can be used to estimate the reservoir characteristics of the geothermal reservoir within the cone of depression in the pressure surface created during the 24-hour flow test of well GS 9-1.

- 1) The Theis non-equilibrium method: Values of drawdown versus time after pumping starts are plotted on logarithmic paper and matched with a time-drawdown type curve. A match point is chosen and the reservoir characteristics calculated using the following equation:

$$s = \frac{114.6 Q W(u)}{T} \quad \text{where: } u = \frac{1.87 r^2 S}{T t}$$

- 2) The Jacob modified non-equilibrium method: Values of pressure reduction (i.e. drawdown) versus time are plotted on semi-logarithmic paper and a straight line is drawn through late time data. This method can only be used when the value of (u) becomes small (i.e. less than 0.01). The reservoir characteristics can be calculated using the following equations:

$$T = 264Q\Delta p \quad S = 0.3Tt_0/r^2$$

- 3) The residual drawdown method: Values of residual pressure or drawdown are plotted on semi-logarithmic paper against the ratio (t/t'). A straight line is drawn through late time data and the transmissivity is calculated using the following equation. Storage coefficient cannot be determined by this method.

$$T = 264Q/\Delta p$$

- 4) Pressure drawdown and buildup method: Values of pressure drawdown vs. time during the flow test and shut-in pressure buildup vs. (t+t)/t during the recovery test is each plotted on semi-logarithmic paper and straight-line drawn through late time data. The reservoir characteristic Kh, which is the equivalent to transmissivity in oil industry nomenclature, can be calculated using the following equation:

$$Kh = \frac{162.6quB}{m}$$

Key to the symbols:

Q = discharge, in gpm
s = drawdown in feet
r = distance from test well to observation point, in feet
t = time after flowing started, in days
T = transmissivity, in gpd/ft.
S = coefficient of storage, fraction
 Δp = the change in pressure per $\log_{10}$ cycle
q = production rate in B/D
u = viscosity, $\mu = 0.5468$ centipoise at 50°C
B = formation value factor; assumed = 1.0 for water reservoir
m = change in pressure per $\log_{10}$ cycle

It is desirable to reinject fluids into compatible formations which will allow ultimate migration of the fluids back into the geothermal reservoir to be reheated and produced again. Due to the complex geological structure at Glenwood Springs, it would be very difficult to determine where to reinject fluids for recirculation without an extensive and costly drilling and testing program. Therefore, this report recommends reinjection at Glenwood Springs primarily as a disposal method rather than for recirculation. Total discharge from all hot springs in the Glenwood Springs area is approximately 3000 gpm and a planned municipal heating district would have a production capacity of 1000 gpm. Therefore it is unlikely that disposal of geothermal fluids, rather than recirculation, would have significant impact on reservoir longevity.

Reinjection can result in some problems primarily due to large volumes of injection fluids and the thermodynamic instability of hot geothermal brines. Some of these problems include increased reservoir pressures, scaling and corrosion of the well bore, plugging and impeding slotted liners in the injection zone, and reducing formation permeability and injectivity due to scaling and suspended solids. Though some of these problems are possible at Glenwood Springs they are not anticipated and can be abated. By comparing the potential impact of reinjection at Glenwood Springs to other geothermal systems we see that reinjection wells at The Geysers, California inject several thousand gpm of geothermal fluids. In the Imperial Valley, California reinjection wells handle fluids with a TDS of 200,000 mg/l. At the Mahiao reservoir in the Phillipines 350°F fluids are being reinjected which contain 1000 mg/l of SiO_2 . After twelve months of testing the reservoir injectivity has increased with no SiO_2 scaling problems. At Glenwood Springs the maximum reinjection rate would be less than 1000 gpm of 100° to 125°F fluids, with a TDS of less than 20,000 mg/l at an SiO_2 content of less than 32 mg/l. Moreover, there are numerous methods of handling potential reinjection problems.

Site Location for a ReInjection Well. Much more hydrological and reservoir information is necessary in order to choose the optimum site for a reinjection well. However, sufficient information is readily available to select a feasible reinjection well site and develop a drilling and testing program.

At Glenwood Springs, there are two geologic regimes (formations) with potential to accept disposal of geothermal fluids. Numerous faults and fractures exist which possibly could be ideal for accepting fluids, and/or permeable sandstone formations are present which are hydrologically separated from the Leadville Limestone. Faults are attractive due to generally higher permeabilities, however, faults may be interconnected with shallow fresh water aquifers, or the primary producing geothermal reservoir, and may allow "short circuiting" of the natural thermal regime. Due to the complex fault zones at Glenwood Springs disposal into faults is very risky. A potential disposal horizon is a 100 foot thick sandstone lense within the Sawatch Quartzite (Cambrian) which lies 700 feet below the Leadville Limestone. From this study there are no data pertaining to porosity, permeability, transmissivity or other pertinent hydrogeologic properties of this formation. For overall planning purposes the assumption will be made that the sandstone horizon within the Sawatch Quartzite is competent for a reinjection aquifer.

The reinjection well site must be located where the disposal of cooler used geothermal fluids will not "short circuit" the thermal regime producing from geothermal production wells or waters flowing from hot springs throughout Glenwood Springs. The anticipated production reservoir is from the Leadville Limestone at a depth from 500 to 800 feet. If the projected sandstone horizon in the Sawatch Quartzite is used for reinjection, its depth is from 1500 to 1600 feet. It is unlikely that disposal into the Sawatch Quartzite will impact the hot waters in the Leadville Limestone because the two formations are isolated from one another by 250 feet of quartzite and 450 feet of confining shales,

limestones and dolomites. The only known faults and fractures in the vicinity of the proposed production and reinjection wells which could (but not necessarily) be connecting the two zones is the low angle Storm King thrust fault. If disposed geothermal fluids migrated up-dip in the Sawatch Quartzite, then ascended the Storm King thrust fault (see Figure IV-3), it is feasible they may be reheated during migration and recharge the geothermal reservoir in the Leadville Limestone.

Critical factors in the siting of reinjection wells are proximities to other wells, users, and costs. Due to high salinities the municipal heating district will use heat exchangers and a fresh water circulating fluid. Since the Leadville Limestone and Sawatch Quartzite apparently are not in communication with each other, it is viable to site the reinjection well immediately at the same location as the geothermal production well and the proposed heat exchanger and boiler building. Figure IV-21 shows the location of the Two Rivers Park site which will be the location of the proposed geothermal production well (GS 9-1), the reinjection/disposal well (GS 9-2R), and the heat exchanger/boiler building.

However, reinjection of the geothermal fluids into the Sawatch Quartzite poses some problems. The continuity of the sandstone layers within the formation would have to be established so the fluids would have a permeable zone to enter. Also, reinjection of the fluids into a formation other than the Leadville would be considered a consumptive use of the geothermal waters, which would require adjudication of the resource water rights.

An alternative disposal method is to reinject the geothermal fluids back into the Leadville Limestone. This reinjection well would be to a depth of 500 to 800 feet (same as the production depth). To prevent impact on the hot waters of the Leadville Limestone, this reinjection well must be located at least 1000-2000 feet upstrike of the proposed production well.

Figure IV-21. Location of Two Rivers Park site. This location is where the geothermal exploration/production well (GS 9-1) and the reinjection well (GS 9-2R) will be drilled.

The advantage to reinjecting into the Leadville is that returning spent fluid to the same reservoir would be considered non-consumptive use. The Leadville Limestone is also known to be porous and permeable and thus should pose no problem in receiving the fluids. The major disadvantage to this method is that due to the high permeability, the reinjection well would have to be located some distance from the producer. This would necessitate preparation of another site and a pipeline connecting the two wellheads.

Well Design and Drilling. The overall well design and drilling procedures for a reinjection well at Glenwood Springs are very similar to those for the geothermal production well, GS 9-1. If the Leadville is used as a reinjection reservoir the well design would be identical to the production well. However, use of the sandstones in the Sawatch as the reinjection reservoir would necessitate smaller bore sizes in the reinjection well and a different completion design throughout the reinjection horizon to keep costs at a minimum. The initial geothermal production well is designed with a production casing of 9-5/8" so as to be large enough to not impede a natural flow of 1000 gpm at land surface. To reduce well costs for the reinjection well (GS9-2R), and since pumping is anticipated for the injection fluids, the overall size of the production casing (that casing down which fluids are reinjected) will only be 4½". Since the first phase of the municipal heating district at Glenwood Springs will not be operating at its full capacity of 1000 gpm it is recommended that the first reinjection well be of a smaller bore than is required for the complete disposal of 1000 gpm. The advantages of a smaller injection well include decreased drilling costs and more rapid drilling times. A smaller well allows for more thorough testing and monitoring of the disposal system prior to a full-scale reinjection program.

The well profile for the small bore reinjection well is shown in Figure IV-22. a 12¼" bore will be drilled to a depth of 40 feet, or through the river gravels and alluvium into the competent Belden shales.

FIGURE IV-22: GS 9-2R Well Profile

Conductor pipe of 10-3/4" (O.D.) will then be set through the gravels and a local redimix supplier can undertake the cement job. Next, a 9-7/8" bore will be drilled to a depth of 200 feet, or shallower if producing zones of water are encountered in GS 9-1. Within the 9-7/8" bore, 8-5/8" surface casing will be set and cemented with 75 sacks of Class "G" cement with 2% CaCl additive. A 7-7/8" bore will then be drilled from the top of the cement plug within the 8-5/8" surface casing, through the following formations:

Belden Formation (shale)
Molas Formation (chert)
Leadville Limestone (limestone)
Chaffee Formation (shale, limestone)
Manitou Formation (limestone, dolomite)
Dotsero Formation (limestone, dolomite)

and approximately 250 feet into the Sawatch Quartzite where the top of the sandstone horizon should be encountered at approximately 1500 feet. Drilling will continue through the sandstone lense with the 7-7/8" bit for 100 feet, or until very hard quartzites are again encountered. Sixteen hundred feet of 4 1/2" casing will be set within the 7-7/8" bore with the bottom 100 feet being slotted casing throughout the reinjection zone. This casing will be set with 400 sacks of Class "G" cement plus 2% CaCl. To prevent cementing of the slotted casing and reinjection zone a "D.V. tool" will be threaded into the casing string above the reinjection horizon. A DV tool is specifically designed to cement casing above the tool without allowing cement to penetrate below the tool. This allows use of slotted casing without hanging slotted liner through the reinjection zone. A liner would create a telescoping effect within the completed well which would in turn cause a pressure increase and require greater pumping demands to dispose of fluids.

It is anticipated that pumping will be required in order to reinject spent geothermal fluids into the disposal horizon. Since disposal is not anticipated to be back into the producing horizon, the benefit of natural convection cycles is not available. It is feasible that the

pressure head created by 1500 vertical feet of water within a $4\frac{1}{2}$ " casing may be sufficient to force fluids into the disposal zone. To describe the flow characteristics of a fluid from a reinjection well into a porous medium, Darcy's Law (Equation IV-12) can be used. This equation can be integrated as:

$$\frac{Q}{A} = \frac{k}{\mu} \frac{dp}{dr} \quad (\text{Equation IV-12})$$

and is applicable to any fluid flowing through a porous material so long as conditions of flow are viscous (Calhoun, 1953). Equation IV-13 is the resulting integral assuming radial flow:

$$P_e - P_w = \frac{Q \mu \ln(r_e/r_w)}{2\pi k h} \quad (\text{Equation IV-13})$$

where:

- Q = volumetric flow rate
- k = permeability
- h = slotted height of the reinjection pipe
- P_e = pressure at the limit of the well's drainage area
- P_w = pressure in the well
- μ = viscosity
- r_e = radius of the well's drainage area
- r_w = radius of the well

Figure IV-23 shows two sets of curves pertaining to the rate of injection and the required height of slotted casing. The dashed lines on Figure IV-23 show a plot of h versus Q using Equation IV-13 for different pipe diameters and fixed values of k (1.0 darcy), P_e-P_w (300 feet of head), μ (0.284 cp) and r_e (2640 feet). For well GS 9-2R the pressure head (P_e-P_w) would equal 1500 feet. The height, h, is the height of slotted casing needed such that the reinjection fluid will flow into the formation without requiring external pumping. The temperature constant for the graphs in Figure IV-23 is 212°F where reinjection temperatures at Glenwood Springs will be nearer 100°F, but the results are only slightly

dependant on temperature. The solid lines on Figure IV-23 show the vertical amount (height) of slotted casing needed for a given flow rate at various formation permeabilities. The casing diameter was fixed at 0.5 feet.

The drilling procedures for well GS 9-2R are nearly identical to those for the full-bore production well, GS 9-1, with the two main differences being a possible smaller bore and greater depths in the reinjection well. Another difference in well GS 9-2R is its completion and cementing in the reinjection zone. Since the sands in the reinjection zone may not be sufficiently competent to keep from sluffing, a slotted casing will be set through this zone to keep the well open. When setting the production casing a "DV tool" will be threaded into the string at the sixth joint (assuming 20 foot strings) from the bottom. When all the casing is set the "DV tool" will be immediately above the reinjection zone at a depth of approximately 1480 feet. A DV tool is technically named a "differential valve packer collar" and it does not allow cement to be pumped downhole below the depth of the tool. The DV tool plugs the casing bore and when cement is pumped downhole it encounters the DV tool and is turned back up the annulus between the casing and the wall of the wellbore. The DV tool allows for cementing casing above the production zone without impacting that zone or requiring the installation of hangers or liners.

Overall drilling costs will be very similar to those for the geothermal production well, GS 9-1. Drilling times should be comparable to the shallower production well since the reinjection well is of a much smaller bore size. The smaller the bore diameter the more rapid the penetration rate. An approximate overall drilling cost for either option of the reinjection well (GS 9-2R) is estimated at \$134,000.

Testing Program. After the reinjection well (GS 9-2R) has been drilled the next major step is a testing program to determine the reservoir's ability to accept disposed geothermal fluids on a long-term basis.

Figure IV-23. Slotted height for various flow rates and permeabilities with no extra pumping (Kauffman and Houghton, 1980).

The reinjection testing program is very similar to the flow testing program designed for the geothermal production well, GS 9-1. Instead of measuring pressure drawdown as the reservoir is being produced, reinjection testing monitors pressure buildup as the reservoir accepts fluids.

The first phase of this program is to record all information and data on any existing wells (either hot or cold) within a 1000 foot radius of the test well (GS 9-2R). On each well it is desirable to determine that well's depth, temperature, casing program and shut-in pressure or static water level. An initial survey of the immediate Glenwood Springs area found no wells with depths greater than 100 feet within a distance of 1000 feet from GS 9-2R. An on-site field survey must be undertaken to locate all existing wells since state and local records do not list all existing wells.

It is imperative to have a monitoring point directly within the disposal formation and since there are apparently no wells in Glenwood Springs drilled to depths of the disposal formations, a slim-hole observation well must be drilled. Ideally, two to three observation wells should be drilled at 50, 100 and 150 foot intervals from GS 9-2R, at 120° angles to one another. Due to cost restraints it is recommended that only one observation well be drilled approximately 100 feet forth-east of GS 9-2R. An observation well at this location would probably be 85 feet shallower than GS 9-2R and would penetrate the disposal horizon. To keep well costs to a minimum the observation well should be between a 4½ to 5-7/8" slim-hole and cased with 2 to 3" PVC pipe which is slotted or screened through the reinjection horizon. The observation well can be drilled while the drilling rig is on location for GS 9-2R and this will keep costs down to a minimum. Prior to casing both the observation well and GS 9-2R it is recommended to run resistivity, bulk density and neutron logs of the reinjection horizon to assist in calculating formation characteristics. Water quality samples should also be taken from the disposal zone in both wells after casing and PVC pipe have been set to isolate the injection horizon.

As in the flow testing program, several shallow water wells and hot springs in the immediate vicinity of GS 9-2R will be monitored for temperature, pressure and water level fluctuations during reinjection tests. Pressure transducers will be attached to several water wells to record pressure increases under static well conditions. Parshall flumes and/or "V-notch" weirs will be installed at select hot spring vents to monitor increased or unaffected flow rates during reinjection tests. Thermistors will be placed down wells and at hot spring vents to record temperature changes.

During initial reinjection tests it is preferable to use fresh water with low TDS concentrations as the reinjection fluid. At Glenwood Springs there are no fresh water sources near GS 9-2R, other than the Colorado River and use of this supply of "fresh" water is not recommended. If fresh water were trucked to the site it would take 30,000 gallons of water to conduct a one hour injection test at 500 gpm. It would take more than three full-size tractor-trailer tankers to supply the water for one test. The most feasible water source would be treated water from the geothermal production well, GS 9-1.

Chemical analyses will be conducted on the produced geothermal fluids to ascertain TDS, suspended solids and potential scaling and formation plugging problems. From these analyses the optimum pre-treatment program can be designed. The produced geothermal fluids may first be routed to a mechanical clarifier where the majority of the suspended solids and silts will be removed. Then the fluids "may" pass through evaporators or settling ponds to precipitate and settle dissolved solids and lastly (if required) the fluids could be treated with acids and/or chemical additives to further remove undesirable constituents. At this point the geothermal fluids are ready for reinjection.

"Pump-in" tests are conducted very similarly to flow tests by using various pulse rates of injection. The treated geothermal fluids from well GS 9-1 will be pumped into well GS 9-2R at rates of 200, 300 and

500 gpm for one hour at each rate. Immediately upon beginning the pump-in tests all observation wells and hot springs will have pressure and water levels recorded at the following time intervals:

<u>Test Duration</u>	<u>Recording Frequency</u>
0 seconds to 1 minute -	every 5 seconds
1 minute to 3 minutes -	every 10 seconds
3 minutes to 10 minutes -	every 30 seconds
10 minutes to 30 minutes -	every 1 minute
30 minutes to 1 hour -	every 5 minutes

Temperature will be recorded at five minute intervals throughout the one hour pulse tests. Between pulse tests the injection reservoir is allowed to recover to its static level and this is determined by monitoring the observation wells and hot springs. Immediately upon completion of each pulse test, temperature, pressure and flow measurements are recorded during the recovery stages at the same time intervals as during pump-in tests. By using standard analytical methods the data from the pump-in pulse tests are used to derive the optimum pumping rate for the longterm reinjection test.

The long-term pump-in test is conducted in the same manner as the pulse tests. Fluids are pumped into well GS 9-2R for 12 to 24 hours at a constant rate determined from the pulse tests. Pressure, temperature, and water level readings are recorded at the observation wells and hot springs at the same intervals discussed herein. After the first hour of testing, the wells can be monitored at one and two hour intervals. From the compiled data of the long-term injection tests, standard analytical methods can be used to calculate values of reservoir characteristics (i.e. permeability, transmissivity and storage coefficient). In addition a computer model could be developed to simulate pressure build-up in the reservoir as a function of time using various injection rates. From these models the long-term pressure build-up effects can be simulated and the optimum long-term injection rate can be calculated so as to have the least negative impact on the disposal reservoir and adjacent water bearing formations. By constantly monitoring temperature changes (if

any) in the wells and hot springs, it can be determined if reinjection will have any thermal impact on the hydrologic system. After the 12 to 24 tests is analyzed, the reservoir engineers will determine if a longer injection test (i.e. 3 to 7 days) is necessary.

It is anticipated that a reinjection program such as discussed herein will have no impact, or at the most minimal impact, on the potable and irrigation water supplies and the natural thermal regimes of the hot springs at Glenwood Springs, Colorado. Some of the aspects that would mitigate the impacts due to reinjection include the absence of water wells deeper than 100 feet in the vicinity of the proposed drilling sites and the fact that the disposal depth is greater than 500 feet and possibly separated from the producing hot water reservoir by 700 feet of confining shales and limestones.

V. INSTITUTIONAL

A. Operating Entity

Broadly speaking, there are two types of possible organizational arrangements capable of constructing and operating the geothermal system: municipal organizations and private organizations. As discussed earlier, a municipal form of ownership is recommended for several reasons. First, the city would be, at least initially, one of the major users of the energy produced. Second, the land on which the wells will most likely be located is owned by the city. Third, the city already owns the electric power distribution system and the water and sewage systems. City ownership of the geothermal system would not only maintain this trend but would also make use of city personnel and equipment already used on somewhat related tasks.

Perhaps the most important reason for city ownership is the small labor cost involved in its operation and maintenance. DRI has estimated that only 18 person-weeks of labor per year are needed to operate, maintain and administer the system. If large, non-productive labor and administrative charges are to be avoided, overall operation of the geothermal system must be a minor interest of any operator. In the case of Glenwood Springs, no other organizations with the capability, trained manpower and equipment to operate the system are known; the city already owns and operates all the related utilities (water, sewage, electricity) other than the natural gas distribution network owned by Rocky Mountain Natural Gas Company (RMNG). DRI does not believe RMNG to be an appropriate owner/operator of the geothermal system due to the fact that the geothermal system will primarily serve to displace natural gas. The potential for conflict-of-interest problems is too great.

A municipally owned and operated system may take a number of different forms. For example, the utility might be operated as either a department of the city government or as a city owned corporation. The

choice of form is beyond the scope of this study. However, the decision must weigh such factors as the legal authority of the city to establish such an organization and the bonding authority of the resulting organization. For example, the city would need to determine whether general obligation bonds or revenue bonds or both could be issued to finance the project.

B. Institutional Aspects

Regulations. In Colorado, and most of the West, there was an historic need to allocate scarce water resources among the many interested parties. Colorado long ago adopted the appropriation doctrine, e.g., he who is first in time is first in right. An individual acquires this priority by adjudicating his rights in court. These rights are protected by law and, in the permitting process, new users must demonstrate no injury to prior rights. Uncertainty as to the exact nature of geothermal resources in Colorado (water or mineral?) is reflected in the state's ambivalent approach to regulations (Vranesh and Musick, 1977). The Colorado Geothermal Resources Act (CRS 34-70-101) cites vested authority in the Oil and Gas Conservation Commission because of the similarity to oil and gas for development of geothermal resources. The Act preserves existing water laws and rights and these are fully applicable to geothermal resources.

The primary role of the Commission is the issuance of well drilling permits and the assurance that their regulations are being followed. A copy of the well permit application (Appendix C) is forwarded to the State Engineer and the Water Resources Commission to determine that there is unappropriated water available for withdrawal by the proposed well and that the vested water rights of others will not be materially injured (CRS 37-90-137). If subsurface disposal is part of the application, then the Oil and Gas Commission will forward a copy to the State Health Department for issuance of a subsurface disposal permit.

The State Engineer will determine any consumptive use of the water. If the water is reinjected into the same formation, there is no consumptive use. If the water is reinjected into a different formation, then the State Engineer must determine: (1) what is this doing to the source? and (2) what is this doing to other aquifers? This latter question is a difficult one for Colorado to handle. There has been an assumption in Colorado that all waters are tributary (geothermal and ground/surface waters are linked); however, recent legislation (State Senate Bill 213) has identified the likelihood of nontributary water, that is, having no impact on surface streams. It is expected that over the next few years, new water doctrines will be developed that consider this "213 water" (State Engineer, 1980).

The Act also preserves the authority of the Water Quality Control Commission in dealing with the spent fluids (Oil and Gas Conservation Commission, Rules of Practice, Rule G.325). The subject of environmental effects is treated later in this section.

Colorado, through its priority system of water appropriation, e.g., "first in time-first in right," grants priorities by court adjudication. New use of water must not cause injury to other water users. It appears somewhat unclear exactly what injury implies. The verbal opinion of the District Water Referee was that decrease in flow of adjudicated rights, presumably caused by a new user, constituted injury. It was further stated that a temperature decrease of 5°F (3°C) in adjudicated flow constituted injury, whereas a decrease of 1 or 2°F (1°C) would not (Cole, 1980). The "injury" caused by a temperature decrease apparently has no documented basis. The water referee has the authority to rule on determinations of water rights and the amount and priority (CRS 37-92-301). (In general, all rules and regulations have as their objective the optimum use of water consistent with preservation of the priority system of water rights [CRS 37-92-501].)

In August 1980, the Hot Springs Lodge Corporation board met to discuss reparation of any injury resulting from the City of Glenwood

Springs proposed geothermal well. The concept considered was for the city to make up from well production any "lost" flow from the adjudicated amount. While the board was ready to state that no injury was expected, they were not ready to commit to any reparation.

Ownership. In 1962, the Glenwood Hot Springs Company conveyed a quit claim deed to Mr. Robert L. Nicholas stating, ". . . all of the medicinal or mineral water, and the springs thereof in, under and issuing out of all the land, and every part thereof within the outermost bounds of the Town of Glenwood Springs. . . ." While this claim has never been tested in court, it is only important for long range development of geothermal in Glenwood Springs since the expected drilling site laid outside the city boundaries in 1962.

The proposed well site (Two Rivers Park) was deeded to the City of Glenwood Springs by the Denver and Rio Grande Western Railroad and was annexed by the city in 1974. While geothermal resources can be specifically excluded from a deed transfer, in this case it was not. The railroad did, however, exclude mineral rights. In a recent court finding, geothermal resources are to be considered as "minerals", consequently Glenwood Springs should request a permit from the railroad to produce geothermal energy from the specific site (Vranesh, 1980).

The following indicates current ownership and adjudicated water rights in the immediate area of the proposed site:

<u>Name of Source</u>	<u>Owner</u>	<u>Adjudicated Flow</u>
● Mammoth Yampa	Hot Springs Lodge	5.0 cubic feet per second
● Drinking Springs	Hot Springs Lodge	Not adjudicated
● Nicholas-Hot Spring #1	Hot Springs Lodge	3.52 cubic feet per second
● Nicholas-Hot Spring #2	Hot Springs Lodge	0.07 cubic feet per second
● Vapor Caves	McFadden	0.1 cubic feet per second
● Gamba Mineral Spring Graves Bath House or Health Spa	Redstone Corp.	?
● Hobo Spring	Redstone Corp.	?

It is the opinion of the Division Water Referee that both the Gamba and Hobo Springs have been adjudicated, but no record of these has been found in the files.

Because court adjudication will protect the rights of the City of Glenwood Springs, the city should file for adjudication on the well. The application for filing should include that flow measured on pumping. Natural (artesian) flow is not necessary (Vranesh, 1980).

Environmental Requirements. The environmental requirements for the development of geothermal energy in the city of Glenwood Springs, Colorado are imposed by both the state and federal governments. There are incremental requirements as the project status progresses from exploratory drilling to full-scale production which are dependent upon the impact on the environment.

The Council on Environmental Quality, Executive Office of the President, has issued regulations for implementing the procedural provisions of the National Environmental Policy Act (NEPA). These regulations reflect the Environmental Quality Improvement Act of 1970, the Clean Air Act and Executive Order 11514, Protection and Enhancement of Environmental Quality. NEPA is the basic national charter for protection of the environment. The purpose of NEPA is to inform federal agencies of the criteria to comply with the procedures and achieve the goals of the 1970 Act. Each federal agency issues its own proposed guidelines for compliance with NEPA. Those issued by the Department of Energy (DOE) were published in the Federal Register, July 18, 1979, pages 42136-42143. Each agency is mandated to utilize a systematic, interdisciplinary approach which will insure the integrated use of the natural and social sciences and the environmental design arts in planning and in decision making which may have an impact on man's environment. For any project with U.S. government support, a federal agency shall be designated as a lead agency and, according to their agency compliance regulations, shall supervise the preparation of an environmental impact statement, if required.

Based on the assumptions of (1) economic feasibility of the project and (2) funding participation by the DOE, the following represents requirements for the City of Glenwood Springs with DOE as the lead agency.

1. The applicant for DOE financial assistance should consult with DOE as early as possible in their planning processes to obtain guidance with respect to the appropriate level and scope of any studies or environmental information which DOE may require to be submitted as part or in support of their application. In 1978, a preliminary environmental report was prepared for the Colorado Geological Survey, State of Colorado, by Kim G. Koulet and James A. Armstrong of the Denver Research Institute on the Drilling and Production Testing of an Exploratory Geothermal Well in the Glenwood Springs, Colorado, which would provide an excellent base for the preliminary submission report to DOE. Copies are available through the Colorado Department of Natural Resources. The document is not site specific but data in the general categories such as ecological environment and socioeconomic environment are applicable.

If funding is secured through the DOE User-Coupled Confirmation Drilling Program (see Section III) a guideline workbook is being generated specifically for Environmental Reports on these projects. These guidelines provide information generic to all projects in this program. The information required by individual contractors is reduced to certain site specific details needed to develop the initial Environmental Report.

2. DOE will at the earliest possible time determine whether an environmental assessment (EA) or an environmental impact statement (EIS) is required. General guidelines for the decision are stated in Section D of the DOE regulations published in the Federal Register.

3. The applicant will conduct studies which are deemed necessary and appropriate by DOE to determine the impact of the proposed action on the human environment.

4. The applicant is required to consult with appropriate federal, regional, state and local agencies and other potentially interested parties during the preliminary factors including permitting requirements are identified. The permits required by the State of Colorado are a drilling permit, a subsurface disposal permit and possibly a water discharge permit which are discussed in more detail later in this section.

5. The applicant will submit applications for all required federal, regional, state and local permits or approvals as early as possible. The Colorado State required permits are stated earlier; the drilling permit application is shown in Appendix , and a copy of the procedure for permit application under "Rules for Subsurface Disposal Systems" is also included there.

6. The applicant is required to notify DOE as early as possible of other federal, regional, state, local and Indian tribe actions required for project completion in order that DOE may coordinate the federal environmental review.

7. The applicant will notify DOE of private persons and organizations interested in the proposed undertaking, in order that DOE can consult, as appropriate, with these parties.

8. DOE will, upon receipt of an application, or earlier if possible, initiate and coordinate any requisite environmental analysis. DOE normally shall use its own funds. The lead agency shall, to the extent available funds permit, fund those major activities or analyses it requests from cooperating agencies. Further specifics will be defined as the system develops and decisions relevant to the impact on the environment are reached.

If the city does not seek federal funding, the environmental impact requirements are vested in the Colorado Department of Health. The Water Quality Control Commission and the Air Pollution Control Commission

are the agencies within the State Department of Health concerned with the environmental issues pertaining to geothermal development. The Air Pollution regulations apply if there is surface discharge of effluents. Utilizing reinjection, contaminants of concern would not be exposed to the atmosphere, thereby eliminating environmental impact from the air pollution standpoint.

The Water Quality Control Division of the State Department of Health determines the standards for discharge to all waters within the state. If the system design were to utilize the Colorado River for discharge of the liquid geothermal effluent, a permit "National Pollution Discharge Elimination System Application for Permit to Discharge Short Form - Sanitary, Industrial," would be required from this agency. The Colorado River Basin area which would be affected by the project is classified by the Colorado Department of Health as B₁. Due to the standards set, feasibility of long-term discharge into the river appears quite remote. As an example, the limit of chloride (mg/l) in discharged waters is 250 for a B₁ classification. Preliminary testing of the thermal waters of Glenwood Springs indicates a chloride content of 11,000 (mg/l). Permission for temporary discharge into the Colorado River for flow test of an exploratory well may be obtained through a letter of intent to the Water Quality Control Division of the State Health Department (attention: Mr. Arden Wallum).

Utilizing reinjection as the system disposal method, it will be necessary to obtain a subsurface disposal permit from the State Water Quality Control Commission. This procedure is initiated simultaneously with the drilling permit application to the Oil and Gas Commission. Although the drilling permit is not dependent upon environmental issues, these are of concern for the disposal permit, as stated in "Rules for Subsurface Disposal Systems," 16 August 1977. However, referencing prior reports will be sufficient as redundancy of the EIS requirement is not intended. The disposal permit process takes approximately 90 days as adopted by the Colorado Department of Health, indicated by the flow

chart contained in Appendix C. A copy of these rules may be obtained from the Underground Injection Control Section of the Water Quality Control Division.

C. Glenwood Geothermal Task Force

The formation of the Glenwood Springs Geothermal Task Force was seen as a method to incorporate the input of local residents into the blueprint for geothermal development. This group was seen as being composed of municipal and state representatives, business, industry and private citizens. The members of this group are:

Gregory Durrett (Environmentalist)	Bill Bowden (Colorado Mountain College)
Ross Jeffery (Developer)	Jerry Gamba (City Councilman)
Gene Allen (City Administrator)	Georgia Bowlby (Chamber of Commerce)
Ray Baldwin (County Administrator)	Diane Richardson (High School Student)
Anna Dubicki (Private Citizen)	Nick Massaoro (Private Citizen)
Henry Bosco (Hot Springs Lodge Owner)	Roy Stachnik (Private Industry/Architect)
Stuart Hirsch (BLM)	

Two general meetings were held with the Task Force: one in October 1979 and the second in February 1980. A brief introduction to geothermal energy was prepared and distributed to the members to increase their awareness of geothermal energy. The major concern of the Task Force was the effect that development might have on the Glenwood Hot Springs swimming pool which is fed by the Mammoth Yampa Spring. This concern played an important role in the overall conduct of the program.

Both meetings concentrated on three issues: first, a status report of the project, second, public attitude towards commercialization of geothermal energy and, third, potential users of geothermal.

The public attitude issue was approached by referring the Task Force to the Nannen, Kreith and West (1975) report. Nannen, et al conducted a survey in 1975 of 227 residents. The questionnaire and results are reproduced in Figure V-1. A few members of the Task Force have reported that the results of this earlier survey are still generally valid.

Recommendations. The City of Glenwood Springs, in order to develop geothermal energy, must progress along the following steps:

1. Obtain permission from the Denver and Rio Grande Western Railroad to produce geothermal energy.
2. File a "Designation of Agent" with the Commission (Appendix C).
3. File an Application for Permit to Drill (Appendix C). The requirements for this application are reproduced here to illustrate the scope of requirements for the permit process.
4. Bonding Requirements (Appendix C) - the owner is required to produce a good and sufficient bond (not less than \$10,000). It is expected that the bond requirements for Glenwood Springs will be waived.
5. After well completion and flow measurements, file for adjudication on pumped flow.

The Rules and Regulations of the Oil and Gas Conservation Commission require some 13 more forms (originally set up for oil and gas drilling permits), but only the Designation of Agent, Drilling Permit Application, and Bonding Requirement forms are currently used.

D. Expansion Potential

The installation of the first geothermal heating system in Glenwood Springs may well set off a rush to add other buildings to the network. The community is well aware of the potential that the resource holds in addition to its present value as a basis for the spa and a source of

Figure V-1

QUESTIONNAIRE AND RESULTS

		Yes	No	No Opinion
1)	Have you ever thought about using hot springs water to heat your home or business?	% 71	28	1
2)	Many homes and businesses in Glenwood Springs are currently heated by natural gas. Are you satisfied with this heating source?	% 45	41	14
3)	One alternative to gas heating is using hot water from wells. This is called "geothermal heating." Would you consider geothermal heating a <u>better</u> alternative if:			
	a) it proved to be less expensive	% 40		
	b) it proved to be about the same in cost	% 53		2
	c) it proved to be more expensive	% 5		
4)	Are you in favor of the present system of city ownership and operation of utilities in Glenwood Springs?	% 53	32	15
5)	If there were a geothermal system, would you prefer that:			
	a) the city own and operate it	% 26		
	b) private industry own and operate it	% 20		6
	c) users co-op own and operate it	% 48		
6)	If a geothermal system were installed in Glenwood Springs and proved to be no more expensive than other systems, new industry might be attracted to this area. Would you be in favor of geothermal energy if it attracted industrial growth to the Glenwood area?	% 49	46	5
7)	A geothermal heating system is innovative and might therefore attract more tourism to Glenwood Springs. Would you be in favor of this?	% 56	33	11
8)	Would you approve of the city floating a bond issue to make the initial investment necessary to build a geothermal heating system?	% 51	43	6
9)	Would you accept an increase in taxes to finance a geothermal heating system if it meant lower heating bills?	% 52	42	6
10)	Do you feel that there are higher priorities for spending tax money than construction of a geothermal heating system? If so, what?			
11)	Assuming that a geothermal system were found to be cheaper than the present one, are there any risks that would concern you about this type of system? If so, what?			
12)	Do you believe there are other advantages in using the geothermal resource for heating?			
What is your age? Under 30 ☐ Sex M ☐ Occupation <input type="text"/>				
30-50 ☐ F ☐ <input type="text"/>				
Over 50 ☐ <input type="text"/>				
How long have you lived in Glenwood Springs? Under 1 year ☐				
1-10 years ☐				
Over 10 years ☐				

Taken from Nannen, et al, 1975.

much tourist income (see survey, Figure V-1). This attitude was anticipated in the conduct of the feasibility study. It is a prime reason for the consideration of the options for system size (capacity for 2 and 4 times the heat load of the 7 public buildings examined in detail) and also influenced the selection and specification of system components.

A second reason for the early consideration of system expansion is the economies of scale shown in the economic analysis (Section III). The system option designated as base case will supply twice the peak demand of the seven buildings included in this study; it shows about 10 times the present value systems savings of the option which supplies only those seven. This is because the cost of the production and reinjection wells is a substantial part of the total system capital cost and was assumed not to change with system size. Since there are no existing wells, a conservative approach would be to drill an exploratory well of sufficient size to provide the needed production at a possible low reservoir pressure. Rig time and some of the other drilling costs are somewhat independent of well diameter, so the savings with smaller diameter wells represent a diminishing return. It only makes economic sense, then, to maximize the output of the wells in order to amortize the cost over the greatest quantity of delivered energy. This reasoning, however, assumes there is a ready market for the additional energy available at the larger system flowrates.

Since the distribution piping for the system will be routed through the downtown area, it would be a simple matter to add other buildings, up to the peak supply capacity of the system. Downtown businesses hold the advantage of relatively large demand per user; in addition, private enterprise can utilize available tax credit incentives to defray part of any discretionary or mandatory retrofit costs that may be incurred.

The Glenwood Springs Public Schools present a very significant potential peak demand of 10 million Btu per hour (3 MW) which could be satisfied with geothermal energy. The old elementary school and Junior

and Senior high schools all use low pressure steam heat, and the new addition to the elementary school has hot water heat; both types are easily converted to geothermal supply, although some discretionary retrofit would be needed. Interest in the results of the study has been expressed on behalf of the school district; however no commitments have been made.

The area of the city north of the Colorado River includes a commercial district along West Sixth Street leading to West Glenwood Springs. This region would also provide an ideal load for an expansion of a geothermal heating system that could possibly be supplied by a second well. There has been no analysis of use in this area, but it is speculated that because of its proximity to Two Rivers Park and the well site proposed here, the economics for such an expansion would be quite favorable.

Several local private developers are investigating the utilization of Glenwoods Springs' geothermal resource. The Redstone Corporation, owner of the Hobo Pool and Gamba Hot Springs, is known to be planning to use the energy from those springs, although no public announcement of the scope of this project has been made. The Rosell Development and Construction Company has requested assistance from the U.S. Department of Energy to evaluate the use of geothermal heat in a new office building planned for the corner of Ninth and Grand Avenues in downtown Glenwood Springs. Others with interests in the hot springs in the area are also said to be contemplating further development of the geothermal resource.

APPENDIX A

DISPOSAL OF SPENT GEOTHERMAL FLUIDS
BY DISCHARGE TO MUNICIPAL SEWAGE
TREATMENT PLANTS

CH₂M Hill
Rocky Mountain Regional Office
P.O. Box 22508
Denver, Colorado 80222

APPENDIX A

DISPOSAL OF SPENT GEOTHERMAL FLUIDS BY DISCHARGE TO MUNICIPAL SEWAGE TREATMENT PLANTS

With the present thrust for safe alternate energy sources, geothermal energy is becoming increasingly attractive as an inexpensive, clean source of heat for both space heating and the production of electricity.

After the desired amount of heat is extracted from the geothermal fluid, it must be disposed of. One alternative is to recover its low-quality heat by adding it to the municipal sewage treatment plant to increase the temperature of the process, thereby increasing the plant's efficiency.

The quality of the geothermal sources varies widely. Sources located in the same geographical area tend to have the same principal chemical constituents, although the concentrations of these primary chemicals were not necessarily similar. A tabulation of the chemistries of several geothermal sources from the draft report Utilization of Geothermal Effluents to Create Waterfowl Wetlands by CH2M HILL, for the U.S. Fish and Wildlife Department, is presented in Attachment I.

The total dissolved solids (TDS) of the geothermal fluid is typically in the 1,000 to 2,000 mg/l range with a pH of approximately 8.0 ± 0.5 (with a range from 2.0 to 9.9). The principal chemical constituents of the listed sites are sodium, sulfate, carbonate, chloride and silica. The presence of heavy metals varied widely between sites.

All geothermal sources having a temperature below 64°C were excluded from Attachment I because these sources do not have enough thermal energy for probable commercial development. The majority of the listed

sites have temperatures under 100°C and will probably be used for space heat. The few sites whose temperatures reach over 150°C could be used for electrical generation.

After the desired amount of heat is extracted, the fluid must be disposed of. The low-quality heat which remains can be recovered by adding the spent fluid to the municipal sewage treatment plant influent to increase the plant's efficiency.

With an increase in temperature, the density of the water will decrease causing a greater difference in densities between the water and the suspended solids. This, according to Stoke's Law, results in a greater terminal settling velocity for the solids and, consequently, an increased solid-liquid separation efficiency. However, the free settling velocity for a particle with a specific gravity of 2.65 would increase by only 0.01% with a temperature increase from 10°C to 20°C.

For anaerobic digestion, less energy will be required for heating, since the influent to the digesters will be warmer.

Keefer (1) has shown that the BOD_5 and suspended solids removal efficiency of the activated sludge process are both increased with increasing temperature. Lin and Heinke (5) ran a regression analysis to determine the relative importance of 10 different individual variables. They found that for both percent BOD removed and percent suspended solids removed, the initial concentration of the particular constituent in the raw wastewater ranks first, and the raw wastewater temperature ranks second; mixed liquor suspended solids third, and detention time in the aeration tank fourth. They suggested that if low temperatures are expected, the aeration tank volume should be increased. This would imply that with an increased temperature, the aeration tank volume could be decreased.

Dougherty and McNary (2), treating a citrus waste by activated sludge, found that temperatures as high as 36°C produce no deleterious effects on the degree of treatment attained. Hussman and Malz (3) determined in their bench-scale laboratory experiments that optimum efficiencies were achieved at 30°C and the poorest at 45°C. Ludzack, Schaffer and Ettinger (4) also found that BOD and COD removals were greater at 30°C than at 5°C, that the accumulation of solids was substantially greater at 5°C than at 30°C and that flocculation was inferior at 5°C.

Autotrol Company, a major manufacturer of rotating biological contractors (RBC), has determined that BOD₅ removal decreases with decreasing temperature below a threshold of 13°C. From 13 to 29°C, temperature has no effect on BOD₅ removal. Nitrification is enhanced with increasing temperature up to at least 18°C. The Autotrol RBC units experience structural problems at elevated temperatures; therefore, Autotrol has not pursued establishing design criteria for temperatures above 29°C.

Wastewater chlorination is also enhanced with increasing temperature. The effect of temperature on the kill rate by chlorine can be described by a form of the van't Hoff-Arrhenius equation (6). The time required to achieve a given kill would be reduced by approximately 45% by raising the temperature from 10°C to 20°C.

With the addition of geothermal fluids to the sewage, not only will the temperature be increased, but because of the high TDS typically associated with geothermal fluids, the TDS will also be increased.

If, by the addition of high TDS geothermal fluids to the sewage, the TDS of the combined stream becomes too great, biological activity may be inhibited. Ludzack and Noran (8) demonstrated that there were no detectable changes observed in the sustained performance of their

bench-scale activated sludge units below chloride concentrations of 5,000 to 8,000 mg/l. Operation at higher chloride concentrations was characterized by poor flocculation, higher effluent solids and about a 10% loss in oxygen demand removal efficiency. Poon and Mikucki (8), using an RBC pilot plant to determine the effect of salinity on BOD_5 removal between the controlled waste stream and a similar waste stream with a 11,540 mg/l chloride concentration, found the effect of the chloride concentration is negligible.

If the geothermal fluid has a sulfide concentration greater than approximately 0.3 mg/l, it may stimulate the growth of filamentous organisms in an activated sludge system which causes a bulking sludge.

When the geothermal fluid is blended with the sewage, a new chemical equilibrium will be established, possibly resulting in a precipitate or scale being formed. Kessick and Manchen (11) observed a 40% increase in total suspended solids and an 11% increase in volatile suspended solids when 39.1 g/l of sea salts were added to primary treated domestic wastewater to synthesize a seawater waste stream. The soluble COD values before and after the addition of sea salts were 85 and 92 mg/l respectively. It was concluded that the addition of sea salts caused a small increase in the soluble organic fraction, possibly as a result of cell lysis, but the majority of the increase in suspended solids was attributed to insoluble organic material with carbonates contributing to the increase in the volatile fraction.

Silica appears to be saturated in several of the geothermal sources. Silica's solubility decreases with decreasing temperature; therefore, as the heat is extracted from the fluid, a scale may form, either as an amorphous silica or as a calcium, a magnesium, or a calcium-magnesium silicate. These are extremely hard scales and are difficult to remove. If the scale forms inside a pipe, it will reduce the effective cross-sectional area resulting in either a reduced flow-rate or a higher pumping cost. If the scale should form in a heat

exchanger, it would act as an insulator and reduce the efficiency of the exchanger. This precipitation could also occur in the sewage treatment plant, depending on the chemistries of the sewage and the geothermal fluid.

The geothermal fluids may contain heavy metals in concentrations large enough to inhibit biological activity. Concentrations of chromium, copper, nickel and zinc either singly or in combinations of up to 10 mg/l would produce at most a 5% reduction in treatment efficiency in an activated sludge plant (10).

Barth et al (12) reported that 50% to 60% of the metals were removed by completely mixed, activated sludge systems. Cheng, Patterson and Minear (9) found that high molecular weight exocellular polymers of the biofloc in a sewage treatment plant provide many functional groupings that may act as binding sites for metals. They found that metal uptake by the biomass under aerobic conditions is characterized by a rapid phase of 3 to 10 minutes followed by a long-term, slow-uptake phase.

The metals will accumulate in the sludge which may preclude land application as a sludge disposal alternative depending on the concentration of the metals in the sludge and the utilization of the land application area.

Any reduced compound in the geothermal fluid, e.g., hydrogen sulfide, ferrous iron or ammonia, will be either oxidized or stripped in sewage treatment plant. This will also increase the oxygen demand of the waste stream.

The addition of geothermal fluids will increase the hydraulic load to the sewage treatment plant, which could overload the clarifiers and any other unit processes that are hydraulically limited. The pumping power requirement cost will also be increased.

The City of Glenwood Springs, Colorado, has several geothermal springs which could be used for space heating municipal buildings. Analytical data for the Springs is presented in Attachment II.

The municipal sewage treatment plant consists of primary sedimentation, rotating biological contractors, secondary sedimentation, chlorination and anaerobic digestion.

The Glenwood Springs Sewage Treatment Plant discharges to the Roaring Fork River and has the following discharge limitations:

- 30 mg/l BOD₅
- 30 mg/l suspended solids
- Less than 21°C
- Less than 570 mg/l TDS

The sewage treatment plant receives approximately 1 mgd of raw sewage at 10°C, with a TDS of 300 mg/l and a BOD₅ of 250 mg/l.

The TDS discharge limitation is the most restrictive. The amount of geothermal fluid which can be discharged to the city sewage treatment without violating its discharge permit ranges from 10 gpm for the present loading to 20 gpm when the facility is at its design capacity. The Water Quality Control Commission can grant a variance for an increased discharge of TDS. Assuming this variance could be obtained, the most restrictive limitation would then be temperature. Assuming the temperature to be 35°C, the spent geothermal fluid could be added at a rate of up to 100% of the flowrate of the sewage without exceeding the temperature limitation.

A reasonable rate of addition which would not severely reduce the hydraulic capacity of the system would be 10% of the total sewage flowrate. At this addition rate, the temperature of the process stream would be raised to 12°C, resulting in a 0.01% increase in the free

settling rate of a particle with a density of 2.65 and an associated increase in the solid/liquid separation process of a similar magnitude. The RBC's BOD removal efficiency would increase by approximately 9% and because of the higher digester influent temperature, a 3,000,000 Btu/day energy savings, which translates to approximately \$2,000 per year, would be realized.

The plant would lose 10% of its hydraulic capacity which could be interpreted to mean a cost of 10% of the plant's total capital cost of \$2,000,000 or \$200,000. This indicates that the benefits derived from the addition of geothermal fluids are relatively insignificant when compared to the loss in capacity in the case of Glenwood Springs.

Although the effects of both salinity and temperature on sewage treatment plant processes have been independently documented, no studies concerning a warm and saline waste, as would be the case at Glenwood Springs, were found. Since geothermal fluids vary so widely in quality, experimentation would be required on a case-by-case basis.

In conclusion, the disposal of spent geothermal fluids in a sewage treatment plant is site specific. For Glenwood Springs, this is a feasible alternative; however, the benefits derived from increasing the temperature of the process are not sufficient to warrant petitioning the Water Quality Control Commission for a variance of the TDS and temperature discharge limitations. Other disposal alternatives which should be investigated include direct discharge and returning the spent fluid to its original stratum.

References

1. Keefer, C.E., "Temperature and Efficiency of the Activated Sludge Process." Journal WPCF, 34, 1186 (November 1962).
2. Dougherty, M.H. and McNary, R.R., "Elevated Temperature Effect on Citrus Waste Activated Sludge." Sewage and Industrial Wastes, 20, 10, 1263 (October 1958).

3. Hussman, W. and Malz, F., "Untersuchungen zur Biologischen Abwasserreinigung auf aerober thermophiler Grundlage." Gas. u. Wasserfach, 100, 8, 189 (February 1959).
4. Ludzack, F.J., Schaffer, R.B. and Ettinger, M.B., "Temperature and Feed as Variables in Activated Sludge Performance." Journal WPCF, 33, 141 (February 1961).
5. Lin, Kwan-Chow and Heinke, G.W., "Plant Data Analysis of Temperature Significance in the Activated Sludge Process." Journal WPCF, 47, 286 (February 1977).
6. Metcalf and Eddy, Inc., Wastewater Engineering. New York, McGraw Hill.
7. Ludzack, F.J. and Noran, D.K., "Tolerance of High Salinities by Conventional Wastewater Treatment Processes." Journal WPCF, 37, 1404 (October 1965).
8. Poon, C.P.C. and Mickucki, W.J., "Rotating Biological Contactors Treat Islands Sailing Sewage." Water and Sewage Works, 62 (February 1978).
9. Cheng, M.H., Patterson, J.W. and Minear, R.A., "Heavy Metals Uptake by Activated Sludge." Journal WPCF, 47, 362 (February 1975).
10. U.S. Department of Health, Education and Welfare, "Interaction of Heavy Metals and Biological Sewage Treatment Processes." Pub. Health Serv. Publ. No. 999-WP-22 (1965).
11. Kessick, M.A. and Manchen, K.L., "Saltwater Domestic Waste Treatment." Journal WPCF, 48, 2131 (September 1976).
12. Barth, E. et al, "Summary Report on the Effects of Heavy Metals on Biological Treatment Processes." Journal WPCF, 37, 86 (1965).

ATTACHMENT I

**Table A-1 State of Idaho.
Hydrothermal Source Chemical Data**

Area	Site No.	County	Location (Twn, Rg, Sec)	Water Source	Temp. (°C)	Flow (gpm)	TDS (ppm)	Sp. Cond. (μmhos/cm)	pH	Al ppm	As ppm	B ppm	Ba ppm	Ca ppm
A ^a .	1	Ada	3N, 2E, 11	W ^b .	76	<1	295	420	8.5		0.007			6
	2	Ada	3N, 2E	W	75				7.3					2
	3	Ada	3N, 2E	W	80		290		9.0	tr*	<0.05	0.14	<0.20	2
	4	Madison	6N, 40E	W										
B.	5	Adams	16N, 2E	SC ^c .	65				7.6					39
C.	6 ^a .	Blaine	4N, 17E, 15	S	70.5				8.0					3
	7 ^a .	Camas	4N, 18E	S	81				7.3					2
D.	8	Boise	8N, 5E, 6	S	80	20			8.1					5
E.	9	Camas	1N, 13E, 29	S	66				8.0					1
	10	Camas	1S, 13E, 34	S	70	25			7.3					4
F.	11	Cassia	15S, 26E, 23	S	96				7.7					130
	12	Cassia	15S, 26E, 31	W	146	650								51
	13	Cassia	15S, 26E, 23	W	143	800	2,000							38
	14	Cassia	15S, 26E, 25	W	147	800								193
G.	15	Elmore	4S, 10E	W	68	500			8.5					1
	16	Gooding	4S, 13E, 31	S	65	1,200			7.5					1
H.	17	Franklin	13S, 42E	S	76				7.3					89
I.	18	Franklin	15S, 41E	S	77				7.0					160
J.	19	Valley	14N, 3E	S	70.5	20			7.7					2
K.	20	Wash.	15N, 1W	S	70				7.8					17
L.	21	Custer	11N, 15E, 11	S	76	1,691	119	413	8.5			0		2
M.	22	Elmore	1N, 10E, 5	S	74									
N.	23 ^a .	Wash.	11N, 6W, 21											
	24	Wash.												

a. Site or unspecified sites in the area are developed.

b. Well.

c. Spring.

*tr - trace amount

Cl ppm	CO ₃ ppm	Cr ppm	Cu ppm	F ppm	HCO ₃ ppm	H ₂ S ppm	Hg ppm	I ppm	K ppm	Li ppm	Mg ppm	Na ppm	NH ₄ ppm	NO ₃ ppm	P ppm	PO ₄ ppm	SiO ₂ ppm	SO ₄ ppm	Sr ppm
3	19			17	120				1.4	0.05		89				0.01	80	21	
9					141				1.3			75					78	23	
10	4	tr*	0.08	14	70	tr*	<0.02		1.6	0.05	0.05	90					160	23	<0.01
					71				17.0			420					110	660	
11					51				2.1			84					86	72	
5					51				1.9			69					96	35	
34					160				4.8			130					120	79	
					51				3.0			54					73	12	
15					226				2.5			99					77	13	
900					36				35			1,110					97	61	
605				5	71				25		1.9	359					91		
661				8	42				35		0.1	389					170		
2,001				4	53			0.24	91	3.10		1,156	0.47		0.25		67	32	6.40
5					74				0.80			87					86	14	
66					141				1.6			91					97	15	
630					491				110			490					55	260	
5,400					699				660			3,100					80	50	
									1.9			100					78		
140					24				3.8			200					72	200	
12	0			15	119				2.4		0	85		0.06		0.07	91	54	

**Table A-2 State of Montana.
Hydrothermal Source Chemical Data**

Area	Site No.	County	Location (Twn, Rg, Sec)	Water Source	Temp. (° C)	Flow (gpm)	TDS (ppm)	Sp. Cond. (μmhos/cm)	pH	Al ppm	As ppm	B ppm	Br ppm	Ca ppm	Cl ppm
A.	1	Lewis & Clark	12N, 6W, 32	W ^b .	97		680	950	7.9			0.1		8	51
	2 ^a .	Jefferson	8N, 3W, 16	S ^c .	57	10	660	929	7.2			0.24		18	10
	3	Jefferson	5N, 4W, 10	S	76	582	420	523	8.5			0.56		2	19
	4 ^a .	Lewis & Clark	10N, 4W, 28	S	62	13	600	796	8.5			0.80		11	33
B.	5 ^a .	Madison	5S, 1W, 28	S	83	21	1,030		7.7		0.025	0.61		6	120
	6	Madison	10S, 1E, 9	S	68	53	363	659	8.6	0.039	0.007	0.04	0.1	0.2	23
	7 ^a .	Madison	4S, 7W, 28	S	53	26	1,860	2,160	6.8			0.92		290	46
	8 ^a .	Madison	3S, 2W, 6	S	50	53	333	471	8.6			0.02		10	6
	9 ^a .	Madison	3S, 1W, 14	S	56.5	88	646	903	7.6			0.10		17	23
	10 ^a .	Madison	2S, 6W, 1	S	72	60	610	808	8.2			0.25		9	31
C.	11	Park	8S, 8E, 32	S	65	132	2,080	2,460	6.5			0.46		320	45
	12 ^a .	Meagher	9N, 7E, 18	W	46	397	1,530	2,220	6.5			9.10		44	180
	13 ^a .	Gallatin	2S, 4E, 14	S	50-55	60	430	624	8.6			0.20		9	46
D.	14 ^a .	Deer Lodge	5N, 10W, 24	S	77	159	1,250	1,510	6.5			0.10		220	
	15 ^a .	Deer Lodge	3N, 10W, 2	S	70	264	560	701	8.4			0.30		4	
E.	16 ^a .	Sanders	21N, 24W, 3	S	45	53	330	376	9.4			0.34		1	8
	17 ^a .	Sanders	18N, 25W, 32	S	43	18	190	205	8.9					4	3
F.	18 ^a .	Beaverhead	4S, 12W, 29	S	49	29	180	209	8.9			0.04		2	2
	19 ^a .	Beaverhead	5S, 15W, 25	S	58	264	670	972	6.8			0.83		10.0	8

a. Site is developed.

b. Well.

c. Spring

CO ₃ ppm	F ppm	Fe ppm	HCO ₃ ppm	H ₂ S ppm	I ppm	K ppm	Li ppm	Mg ppm	Na ppm	NO ₃ ppm	Pb ppm	PO ₄ ppm	SiO ₂ ppm	SO ₄ ppm	Sr ppm	U ppm	Zn ppm
	20.0	0.02	260			10.0	2.00	0.5	210	1.00			69	180	0.07		
1	8.4	0.02	480	0.5		9.5	0.32	3.5	220		0.1	0.02	66	89			0.06
4	11.0	0.02	161			3.8	0.24	0.1	120		0.1		100	74			0.01
5	9.4	0.70	210	0.5		5.8	0.48	0.9	160		0.1		98	170			0.02
	11.0	0.02	442			17.0	0.26	0.6	340			0.06	96	220	0.18		
9	18.0		157		0.01	1.9	0.08	0.8	120	0.28	0.003		55	53	0.07	0.0006	
1	3.3	0.10	230	1.1		24.0	0.18	73.0	160		0.1		46	1,100			0.08
2	6.2	0.02	63	0.5		1.6	0.05	0.1	91		0.1		46	140			0.01
1	7.4	0.02	380	1.0		10.0	0.09	3.2	180		0.1		88	130			0.04
2	8.7	0.02	170	1.0		6.4	0.34	0.3	170		0.1		110	190			0.01
1	3.6	0.16	297	1.0		23.0	0.24	58.0	230				49	1,200			0.01
0.1	7.4	0.11	830	0.7		20.0	1.30	12.0	480		0.1		51	310			0.02
3	9.2	0.02	132	0.6		2.8	0.04	2.7	120		0.1		66	110			0.01
1		0.05	258	0.7		26.0	0.36	22.0	120		0.1		56	670			0.11
		0.02		1.6		3.9	0.64	0.1	170		0.1		85				0.10
	5.6		189	7.4		1.7	0.04	0.1	85				70	38			0.01
0	2.1		71			1.5	0.01	0.2	39				77	29			
4	2.6	0.02	77	0.9		0.7	0.05	0.1	48		0.1		55	27			0.01
1	2.0	0.02	610	0.6		10.0	0.32	3.7	240		0.1		52	45			0.12

Table A-3 State of Nevada.
Hydrothermal Source Chemical Data

Area	Site No.	County	Location (Twp., Rg., Sec)	Water Source	Temp. (°C)	Flow (gpm)	TDS (ppm)	Sp. Cond. (umhos/cm)	pH	Ag ppm	Al ppm	As ppm	B ppm	Ba ppm	Be ppm	Bi ppm	Br ppm	Ca ppm	Cd ppm	Cl ppm	CO ₂ ppm	Cr ppm	Cs ppm	Cu ppm	F ppm	Fe ppm	HCO ₃ ppm	
A	1	Churchill	19N, 31E	W ^b	96			6,910					15					108		2,200	<1				5		90	
	2	Churchill	19N, 31E	W	100			7,420	7.5									91		2,080	0						104	
B	3	Elko	33N, 52E, 33	S ^c	79			625	7.6									60		12							335	
C	4	Elko	34N, 55E	S	87																							
	5	Elko	34N, 55E	S	88																							
D ^a	6	Eureka	31N, 48E, 8	S	98	26		1,020	9.0			2.1						1		69	32				17		321	
	7	Eureka	31N, 48E, 17	S	88						0.5			0.05		0.01	0.14	1		56		0.20				<0.07		
	8	Eureka	31N, 48E, 17	S	78						0.01			0.19			0.12	3		42		0.12				0.07		
	9	Eureka	31N, 48E, 17	S	84		964	1,006	9.7 <0.02		0.002			0.04	<0.005	0.01		9	0.010	67	152	<0.02	1.04	<0.01	19	0.9	0	
	10	Eureka	31N, 48E, 17	S	96		1,100		9.5			2.2						<1		44	161					148		
	11	Eureka	31N, 48E, 17	S	77						0	7						2		47	173			11	tr [*]	129		
	12	Eureka	31N, 48E, 17	S	96				9.5		0	2					0.4	0.8		30	149			15	0.04	116		
	13	Eureka	31N, 48E, 17	W	100		1,256	1,211	9.9 <0.004		0.02			0.10	<0.005	<0.1		10	<0.002	62	288	<0.04	1.02	<0.004	16	0.05	0	
	14	Eureka	31N, 48E, 17	W	100		1,200	1,130	9.7	0.66	0	2.4					0	0.8		49	224			15	0	39		
	15	Nye	11N, 43E, 7	S	88	450	367	472	8.7	0.1		0.3						1.2		12	24				15	0.05	112	
	16	Nye	11N, 43E, 7	S	92	150	382											31	13	15						tr [*]	102	
	17	Nye	11N, 43E, 8	S	95	92		479	8.3			0.2						1.3		12	3			14			146	
	18	Nye	11N, 43E, 8	W	94	79		499	8.3			0.2						1.4		12	3			15			165	
	19	Nye	11N, 43E, 8	W	100	25	390	488	9.3 <0.004		0.0001			0.0001	<0.005	<0.1		9	<0.002	15	44	<0.04	0.32	<0.004	16	0.06	76	
F	20	Humboldt	36N, 40E, 29	S	74	198		810	6.5			1.1						33		18	<1			2		429		
G	21	Lyon	15N, 25E, 16	W	97	400	1,130	1,580	8.3			1						39		46	2			8	0.02	68		
	22	Lyon	15N, 25E, 16	W	97			1,550	8.5									38		46							70	
	23	Lyon	15N, 25E, 16	S	94			1,610	8.1			10						39		55				8		74		
	24	Lyon	15N, 25E, 16	W	105	25	1,090	1,490	8.0									37		45				8	0.01	80		
	25	Lyon	15N, 25E, 16	W	108			1,279										37		52	6			9	0.02	73		
	26	Lyon	15N, 25E, 15	W	100		1,250	1,656	8.6 <0.02		0.001			0.14	0.007	<0.1		46	<0.010	54	12	<0.02	0.001	<0.01	9	0.41	49	
	27	Lyon	15N, 25E, 15	W	97	400	1,210	1,630	8.6			1						40		49	12			8	0.06	52		
H	28	Pershing	28N, 32E, 33	W	66		5,040	10,200	7.9			5.4						115		2,580	0			4	0.40	186		
I	29	Washoe	32N, 23E, 10	S	97				7.7									73		2,150	0						84	
	30	Washoe	32N, 23E, 10	S	64				7.7			10						80		2,430	0			5			83	
	31	Washoe	32N, 23E, 10	S	75				7.6									73		2,100	0						90	
	32	Washoe	32N, 23E, 10	S	98				7.4									95		2,100	0							
	33	Washoe	32N, 23E, 10	S	93		7,800		7.6									73		2,880	0						66	
	34	Washoe	32N, 23E, 10	S	63				7.8									75		2,180	0						82	
	35	Washoe	32N, 23E, 10	S	96			7,620	7.1									68		2,190	0						156	
	36	Washoe	32N, 23E, 15	S	63				7.6									74		1,915	0						74	
	37	Washoe	32N, 23E, 15	S	86			7,610	7.2			9.9						68		2,200	<1			4			83	
	38	Washoe	32N, 23E, 15	S	84		4,596	7,830	8.1 <0.02		0.003			<0.04	<0.005	<0.1		89	0.01	2,238	0	<0.02	4.76	<0.01	5	0.09	91	
	39	Washoe	32N, 23E, 15	S	65				7.8									70		2,340	0							
	40	Washoe	32N, 23E, 15	S	84			7,600	7.7			10						96		2,350	0			5			83	
	41	Washoe	32N, 23E, 15	S	78				7.0									73		2,130	0							
	42	Washoe	32N, 23E, 16	S	65				8.2									75		2,100	0							
	43	Washoe	32N, 23E, 16	S	74				7.2									174		2,075	0							
	44	Washoe	32N, 23E, 16	S	85				7.0									73		2,130	0							
	45	Washoe	32N, 23E, 16	S	67			6,800	7.9									66		2,100	400						0	
	46	Washoe	32N, 23E, 16	S	67													66		100	400							
	47	Washoe	32N, 23E, 15	S	100		4,486			tr [*]								5		2,146	0					tr [*]	97	
J	48	Washoe	26N, 20E, 12	W	82		4,615	7,100	7.4									163		1,950	0						50	
	49	Washoe	26N, 21E, 6	W	67	50	3,676	6,072	8.1 <0.01		<0.001			0.005	<0.005	<0.1		282	0.006	1,841	0	<0.02	4.17	<0.01	3	0.02	11	
	50	Washoe	26N, 21E, 6	W	66		4,225	6,500	8.4			6.1						260		1,880	0			3			22	
	51	Washoe	26N, 21E, 6	S	66		4,680	7,200	7.6									315		1,850	0						100	
K ^a	52	Washoe	19N, 19E, 25	W	64		780	1,035	8.1	2.0		1.4						16		33	0			4			131	
	53	Washoe	19N, 19E, 25	S	38-93		661											21		34				2.00			126	
	54	Washoe	19N, 19E, 26	W	78		1,057	1,320	8.2			1.2						25		53				6			101	
	55	Washoe	19N, 19E, 26	W	85		1,012	1,430	7.8			2.1						22		53				5			99	
	56	Washoe	19N, 19E, 26	W	85		984	1,423	8.4			2						14		54				5			97	
	57	Washoe	19N, 19E, 26	W	85		1,033	1,454	8.3			2.1						13		54				5			108	
	58	Washoe	19N, 19E, 26	W	90		975	1,367	8.3			2.0						23		50				5			86	
	59	Washoe	19N, 19E, 26	W	90		918	1,185	7.7			1.8						29		42				5			146	
	60	Washoe	19N, 19E, 26	W	82		980	1,327	7.9									33		52					tr [*]	tr [*]		
	61	Washoe	19N, 19E, 26	W	80		959	1,070	7.5		tr [*]		1.7					20		53				5			95	
	62	Washoe	19N, 19E, 26	W	85		969	1,345	8.0			1.9																

H ₂ S ppm	Hg ppm	I ppm	K ppm	Li ppm	Mg ppm	Mn ppm	Mo ppm	Na ppm	Nb ppm	NH ₄ ppm	NI ppm	NO ₃ ppm	Pb ppm	PO ₄ ppm	Ra μg/g	Rb ppm	Sb ppm	Sc ppm	Se ppm	SiO ₂ ppm	Sn ppm	SO ₄ ppm	Sr ppm	S ₂ O ₃ ppm	Ta ppm	U ppm	W ppm	Zn ppm	
			42	1.9	1.7			1.480												170		190							
					1.0			1.400														190							
			16		15.0			45												70		52							
			16	1.3	<0.1			230												320		130							
			8			<0.003	0.02	210									0.15	0.01	<0.00002		330						<0.0002	0.15	
			31			0.12	0.003	250									0.2	0.005	0.00007	0.001	300						0.001		
<0.0005			14	2.6	0.8	0.01		229		0.5	0.05	<0.1	0.06	<0.1			0.27	0.10		345	0.05	128	0.02						2.32
			29		<1.0			241												444		78							
			33		0			239		4.0										449		97			1.0				
0			16	1.3	0	0		230		0.5		0.4								373		89	0						
5.5			31	3.2	0	<0.01		263	10.0	0.9	0.03	<0.1	<0.02	<0.1			0.63	0.20		458	<0.20	127	0.04		5.0				0.01
<0.0002			0		0.2			332		0.4		0		0.06					<0.001	534		90	0.21						
			2		0	0		104				0		0.1	0.2					105		40					0.10		
					3			80											0		88		60						
			3	0.3	0.1			110													98		53						
			3		0.1			110	10.0												105		55			5.0			
0.0004			3	0.7	0.02	0.01		111		<0.1	0.02	<0.1	0.02	0.9			0.06	0.20		<0.001	105	<0.02	49	0.04					0.03
			22	0.4	6.8			130													66		56						
			12		0			291				0								99		596							
			15		0.2			277												115		580							
			14		0.1			300												110		620							
			12		8.7			276				0								100		556							
<0.0005			14	0.3	0.1	0.04		332		0.5	0.08	<0.1	0.07	0.2			0.15	0.10		<0.001	100	0.05	658	0.25					1.03
			13		1.0			313				0								109		642							
			120		19.0			1,700				42.0									76		282						
			121		2.2			1,440													184		386						
			130		2.3			1,800													186								
			110		2.0			1,560													178								
			140		1.0			1,610													174								
			135		2.0			1,590													172		360						
			148		2.2			1,590													176								
			134		2.4			1,560													172		410						
			130		1.0			1,380													182		356						
0.0007			130		1.2			1,400													165		400						
			113	3.5	1.0	0.0002		1,548		0.6	0.05	0.7	0.06	0.2			1.73	0.30		<0.001	170	0.05	385	0.40					0.14
			133		2.2			1,420													192								
			136		2.3			1,360													172		400						
			140		2.3			1,600													180		360						
			135		2.8			1,530													172								
			134		2.5			1,540													172								
			143		2.4			1,470													165		290						
			126		8.1			1,510																					
					8.1			510													199		363						
								1,576																					
0																													
<0.0001			120		0.1			1,040													117		335						
			31	0.8	0.1	<0.0001		1,080		<0.1	0.02	<0.1	<0.02	<0.1			0.80	<0.10		<0.001	95	<0.02	338	4.20			0.008		0.02
0			160		0.1			1,100													110		340						
2			280		0.4			1,150													82		330						
			5.5	0.14	0.4			189					0.11							93		305							
					2.0			167													97		264						
			8		0.3			293					0.2								103		465						
			7	0.8	0.8			259					0.11								92		478						
			8	0.2	0.2			243													111		448						
			8	0.2	0.2			226					0.06								114		463						
			7	0.2	0.2			243					0.19								102		457						
			7	0.2	0.8			203					0.04								135		348						
			9		0.9			241													95		478						
			7	0.2	0.3			248					0.09								104		419						
			8	0.2	0.1			236					0.11								106		455						
			7		0.4			89													5		2						
			56	6.0	0.5			605													222		105						
					11.0			630														130							
			71	7.6	0.8			653													293		100						
			66	7.5	0.7			680													270		73						
5			75	7.0	0.5			707													317		129						
0.1			71	7.6	0.8	0.0005		653													293		100	0.05					
					3.0			390														26							
					8.8			5.8														72							
					18.0			18														72							
			63		1.0			667													245		122						
			66		1.4			728													245		128						
			64	7.6	1.0			640																					

**Table A-4 State of New Mexico.
Hydrothermal Source Chemical Data**

Area	Site No.	County	Location (Twn, Rg, Sec)	Water Source	Temp. (° C)	Flow (gpm)	TDS (ppm)	Sp. Cond. (μmhos/cm)	pH	Al ppm	As ppm
A.	1	Hidalgo	25S, 19W, 7	W ^b .	99		1,057	1,560	9.1		
	2	Hidalgo	25S, 19W, 7	W	96		1,110	1,510	7.6		
	3	Hidalgo	25S, 19W, 7	W	102						
	4	Hidalgo	25S, 19W, 7	W	75		620	835			
	5	Hidalgo	26S, 20W	W	99						
B.	6 ^a .	Dona Ana	23S, 2E, 34	W	25-45		1,000	1,460	8.1	0.04	0.01
C.	7 ^a .	Grant	13S, 13W, 10	S ^c .	52	10	335	390	8.4	0.08	0.004
	8 ^a .	Grant	13S, 13W, 5	S	64			620	7.5	0.03	
	9	Grant	12S, 13W, 31	S	65	47	508	460	7.2		
D.	10 ^a .	Catron	5S, 19W, 35	S	37	6	223	242	9.2	0.23	0.007
E.	11 ^a .	Taos	24N, 8E, 24	S	37-45	350		3,900	6.6	0.03	
	12 ^a .	Sandoval	20N, 3E, 29	S	49	323	150	122	7.7		0.003
	13 ^a .	Sandoval	18N, 2E, 23	S	76	1	1,960	3,460	7.1		0.78
	14	Sandoval	19N, 3E, 4	S	70		4,240	17,300	2.0		
	15	Sandoval	20N, 3E, 35	W	135-285		2,970	2,225	8.0		
	16 ^a .	Sandoval	18N, 2E	S	66				7.2		
	17	Sandoval	19N, 2E, 13	W	197		2,500	2,920	7.4		
F	18 ^a .	Socorro	3S, 1W, 22	S	33	292	220	550	8.4		0.05

a. Site is developed.

b. Well.

c. Spring.

B ppm	Br ppm	Ca ppm	Cl ppm	CO ₃ ppm	F ppm	Fe ppm	HCO ₃ ppm	I ppm	K ppm	Li ppm	Mg ppm	Mn ppm	Na ppm	NO ₂ ppm	NO ₃ ppm	PO ₄ ppm	Se ppm	SiO ₂ ppm	SO ₄ ppm
0.45		18	89	23	12	0.05	32		16	0.66	0.1	0.16	302	0.01	0.20	0.02		103	490
		22	80	0	13		153				1.5				0.20			135	459
		20				0.63			24	0.80	0.1		347						
		28	42				228		8		11.0		150						169
		22	82				159		21				324					154	475
0.35	1.11	17	580	0	3	1.50	242	0.03	32	0.25	12.3	1.50	275	0.003		0.01	0	49	
1.72	0.67	10	67	1	3	0	101	0.01	2	0.13	0.1	0.04	105	0.005			0	58	
	0.85	20	106	21	9	0.05	104	0.14	3	0.32	0.1	0.10	148					53	97
0.12		16	108	0	10	0	128		4	0.20	0.1	0	177					80	84
0.037	0.76	3	12	19	2	0.08	97	0	0.15	0.10	0.1	0	69	0.12		0.05	0.005	40	
1.00	0.66	29	237	0	13	0.06	2,073		31	4.30	8.5	0.15	980	0	0.12			55	149
0.04	0.06	5	2	0	1	0.16	61		2		0.3	0	23			0.21		76	9
7.40	3.00	160	700	0	4	0.45	773		63	7.80	6.6	0.30	510	0	0	0.30		71	43
0.10		72	20	0	1	76.00			34	0.02	18.0	1.30	25		0.40			185	4,520
		0.28	121		24	12.60	623		27		0	0.50	83		0				335
		138	795				735		70				572					93	49
		78	400		3		1,300				42.0		550					115	200
		22	13	0.4	0.22	0.25	157		3		3.1	0.05	52		0.96		0.014		29

**Table A-5 Northern California.
Hydrothermal Source Chemical Data**

Area	Site No.	County	Location (Twn, Rg, Sec)	Water Source	Temp. (°C)	Flow (gpm)	TDS (ppm)	Sp. Cond. (μmhos/cm)	pH	Al ppm	B ppm
A.	1	Lake	13N, 7W	S ^b .	99				8.1		828
	2	Lake	13N, 7W	WC.	186						
B.	3	Lassen	28N, 15E, 8	S	95	132	879	2,860	8.4		4.0
	4	Lassen	28N, 16E, 5	W	107						
	5 ^a .	Lassen	29N, 15E, 23	S	96						
C.	6	Modoc	38N, 7E, 12	S	79	53	820	2,300	8.5		2.5
	7	Modoc	42N, 10E, 29	S	110						
	8	Modoc	42N, 17E, 6	W	98	79		2,700	8.4		5.7
	9	Modoc	38N, 8E, 15	S	78	4	880	2,600	8.6		3.2
	10	Modoc	42N, 10E	S	95	325					
	11	Modoc	42N, 10E, 29	S	95						
	12	Modoc	42N, 10E, 29	S	91	331	899	2,800	8.1		3.8
	13	Modoc	39N, 5E, 9	S	75	79	941	2,500	7.6		3.9
	14	Modoc	44N, 15E, 23	W	160						
	15	Modoc	43N, 16E, 12	S	85	132	1,110	3,300	7.7		7.6
	16	Modoc	45N, 16E	S	86	<1.0					
	17	Modoc	39N, 14E, 29	W	77	3	1,220	3,000	7.8		4.5
	18	Modoc	44N, 16E, 24	S	96	0	1,210	3,740	7.4		6.3
D.	19 ^a .	Mono	5N, 25E, 34	S	69	13			6.7	0.004	9.9
E.	20	Napa	9N, 6W	S	98	520			9.0		9.2
	21	Napa	9N, 7W, 26	W	137						
F.	22	Plumas	22N, 14E, 13	S	73	26	1,370	3,870	8.2		7.4
	23	Plumas	22N, 14E, 13	S	70	21	1,360	3,740	7.9		7.3
	24	Plumas	21N, 14E, 32	W	94	13.2	1,570	4,720	7.9		8.8

Ca ppm	Cl ppm	CO ₃ ppm	Cs ppm	Cu ppm	F ppm	Fe ppm	HCO ₃ ppm	H ₂ S ppm	Hg ppm	K ppm	Li ppm	Mg ppm	Mn ppm	Na ppm	Rb ppm	SiO ₂ ppm	SO ₄ ppm	Zn ppm
26	900				1.4		2,600			44	6.4	23		1,340		203	680	
14	160	2			4.4		44			5	0.08	<0.1		250	0.02	95	300	0.005
30	93	1			2.0		30			3	0.1	0.1	0.01	220	0.01	68	370	
16	200	2			5.1		57			5	0.1	0.1	0.01	280	0.03	100	320	0.014
30	110	2			2.6		31			6	0.12	0.1	0.01	240	0.02	85	370	
29										6.4				231		127		
20	160	1			2.1		45			6	0.15	0.1	0.01	250	0.02	110	300	
44	120				1.9		49			5	0.17	0.2	0.01	230	0.02	87	400	
28	220				5.4		63			9	0.15	0.1	0.01	300	0.04	110	370	0.005
11							124			16				343		182	330	
19	150				4.0		63			11	0.4	0.1	0.012	330	0.06	130	510	
7.7	220	0			7.6		112			15	0.24	0.1	0.01	320	0.08	200	320	0.005
64	200		0.4	0.02	4.5	0.05	1,880	0.5	0.0001	55	2.5	18	0.02	1,110	0.4	100	920	0.18
4.5	215				12.0		0.5			9	2.1	0		193		139	12	
37	460	0	0.2		2.2	0.06	41			7	0.42	0.1	0.022	410	0.06	60	340	
38	460	1	0.2		2.2	0.06	51			7	0.40	0.1	0.03	400	0.06	62	330	
39	540	1	0.2		2.6	0.06	50			13	0.65	0.1	0.01	450	0.11	98	370	

**Table A-6 State of Oregon.
Hydrothermal Source Chemical Data**

Area	Site No.	County	Location (Twn, Rg, Sec)	Water Source	Temp. (°C)	Flow (gpm)	TDS (ppm)	Sp. Cond. (μmhos/cm)	pH	Al ppm	As ppm	B ppm	Ba ppm	Br ppm	Ca ppm	Cl ppm
A ^a .	1	Lake	39S, 20E, 27	S ^b .	88	200		1,370	7.8	0.01	0.07	11.2	0.1	1.0	9	170
	2	Lake	39S, 20E, 27	S	85	189	905	1,320	7.3			9.9			9	146
	3	Lake	38S, 24E, 27	S	78	200		1,490	7.3	0.02	0.46	13.6	0.1	0.4	16	240
	4	Lake	38S, 24E, 34	W ^c .	99	3,785	1,130	1,580	8.7	0.65		18.0		0.9	10	263
	5	Lake	38S, 25E, 10	S	68	70		513	7.9	0.01	0.10	2.2		0.4	8	56
	6	Lake	39S, 20E, 4	S	96	2,300		1,120	7.8	0.03	0.06	6.9	0.1	0.4	13	120
	7	Lake	39S, 20E, 4	S	86	19	821	1,140	8.4			7.1			8	120
	8	Lake	39S, 20E, 4	S	98	19		1,110	8.3			7.2			12	116
	9	Lake	39S, 20E, 27	S	69	186	531	813	7.7			7.0			15	99
	10	Lake	38S, 45E, 20	W	88			1,460	8.1			13.0				248
B ^a .	11	Malheur	18S, 45E, 20	S	73			1,530	7.5	0.02		9.4	0.1		19	360
C	12	Harney	37S, 33E, 15	S	74	29	1,440	2,050	7.6			12.0			15	255
	13	Harney	37S, 33E, 15	S	79		1,520	2,160	8.1			14.0			14	270
D ^a .	14	Klamath	38S, 9E, 28	W	73	151	881	1,230	8.7			0.9			25	56
	15	Klamath	40S, 9E, 34	W	93	17,034		1,030	8.9			0.7			15	59
	16	Klamath	38S, 9E, 33	W	71		812	1,100	8.5			0.7			22	50
	17	Klamath	38S, 9E, 28	W	81		833	1,160	8.8			1.0			23	54
	18	Klamath	40S, 9E, 27	W	90	1,703		920	9.5		0.01	0.8			15	56
	19	Klamath	38S, 9E, 28	W	89		816	1,000	8.6	0.03	0.02				25	48
	20	Klamath	38S, 9E, 20	W	88	946		1,050	8.2			1.0			24	58
	21	Klamath	38S, 9E, 33	W	89	38		1,200	8.3			1.0			27	54
E ^a .	22	Union	3S, 38E													

a. Site or unspecified sites in the area are developed.

b. Spring.

c. Well

CO ₃ ppm	Cs ppm	Cu ppm	F ppm	Fe ppm	HCO ₃ ppm	H ₂ S ppm	Hg ppm	I ppm	K ppm	Li ppm	Mg ppm	Mn ppm	Na ppm	NH ₄ ppm	NO ₃ ppm	Pb ppm	PO ₄ ppm	Rb ppm	Sb ppm	SiO ₂ ppm	SO ₄ ppm	Sr ppm
2	0.1	0.01	5.4	0.02	232		0.0017	0.10	9.0	0.15	0.10	0.02	280	1.80		0.06	0.18	0.04	0.2	130	240	0.17
			6.9	0.02	208				8.8		1.40		268		0.30					140	223	
1	0.1	0.01	4.9	0.02	153		0.0004	0.10	11.0	0.40	0.20	0.03	280	0.60		0.06	0.58	0.07	0.2	180	200	0.12
36			5.2	0.15	70	0.3		0.10	12.0	0.39	0.50		298		1.00		1.4			169	209	0.31
1	0.1	0.01	3.5	0.02	105		0.0001	0.03	7.9	0.04	1.00	0.02	92	0.18		0.06	0.18	0.02	0.2	77	59	0.05
1	0.1	0.01	4.4	0.02	79		0.0004	0.08	8.5	0.15	0.10	0.02	210	0.31		0.06	0.25	0.04	0.2	140	260	0.32
5			4.5	0.01	64				10.0		2.40		208		0.30					140	258	
6					62				9.5	0.20			209		7.20					146	265	0.50
			3.1	0.06	84				2.2		0.40		152		0.20					66	152	
									10.0	0.33			281									
	0.1	0.01	6.1	0.02					16.0	0.28	0.80	0.04	310	1.00		0.06		0.09	0.2	130	100	
			7.0		382				27.0	1.50			430		1.20					119	319	
			7.0		414				30.0	1.50	0.30		456		1.30					173	339	
8			1.6		32				4.4				221							87	431	
2			1.5		48				4.0	0.08	0.10		200							90	360	
4			1.4		43				3.8				207		0.20					83	393	
8			1.2	0.04	32				4.2				213							81	403	
9			1.5	0.26	37				4.1				190							90	270	
16			1.1	0.03	22				3.5		1.04	0.02	331	0.54	0.01					73	384	
			1.4		44				3.9		0.01		195							31	400	
			1.2	0.03	46				3.0		0.20	0.03	370							78	462	

**Table A-7 State of Utah.
Hydrothermal Source Chemical Data**

Area	Site No.	County	Location (Twn, Rg, Sec)	Water Source	Temp. (°C)	Flow (gpm)	TDS (ppm)	Sp. Cond. (μmhos/cm)	pH	B ppm	Ca ppm	Cl ppm	F ppm	Fe ppm	HCO ₃ ppm	Li ppm	K ppm	Mg ppm	Na ppm	K ppm	NO ₃ ppm	SiO ₂ ppm
A.	1	Beaver	26S, 9W, 34	W ^b .	85	1	7,040	11,500				19	3,810	7	158		420	3.3	2,080	1.9	405	65
	2	Beaver	30S, 12W, 21	W	85	11	1,500	2,120	8.1		83	210	14	0.13	384		49	9.7	360	1.0	110	480
	3	Beaver	30S, 12W, 28	W	77	19	1,490	2,170	7.8		72	220	7	0.05	360		61	9.8	360	0.1	120	470
	4 ^a .	Millard	25S, 7W	W	77																	
	5 ^a .	Beaver	27S, 9W, 3	W	133																	
	6 ^a .	Beaver	27S, 9W, 3	W	205		7,067		6.3	25	8	4,090	5		180	20	448	0.01	2,437	0.1	560	59
	7 ^a .	Beaver	27S, 9W, 3	W	260		6,442		6.5	29	10	3,400	5		200	19	410	0.24	2,000	tr*	560	54
B.	8	Box Elder	9N, 3W, 27	W	74	40	3,350	5,300			56	1,100			1,620		110	62	1,000			14
	9 ^a .	Box Elder	10N, 2W	S ^c .	105	5	85,000															
C.	10	Sevier	25S, 4W	S	64	100	4,970	7,520	6.6		264	1,690	6		412		45	44	1,380	0	84	1,250
D.	11 ^a .	Sevier	25S, 3W	S	76	40	2,700	4,100	7.6		282	630	3	0.07	354		63	34	562	0	54	898
	12 ^a .	Sevier	25S, 3W	S	77	40	2,600	4,100	7.8		200	665	3		159		66	34	597	0.3	51	928
E.	13	Sevier	22S, 1W	W	66																	
F.	14	Iron	36S, 15W, 18	W	149	1,000		4,000														
G.	15 ^a .	Salt Lake	4S, 1W	W																		
	16 ^a .	Salt Lake	3S, 1W	W																		

a. Site is developed.

b. Well

c. Spring

*tr — trace amount.

ATTACHMENT II

Table 1. Physical Properties and Chemical Analysis of Thermal Waters in Colorado.

Glenwood Springs Area: Vapor Caves, Mens Hot Spring

Location: 39°32'59"N. Latitude; 107°19'17"W. Longitude; T. 6 S., R. 89 W., Sec. 9 ad, 6th. P.M., Garfield County

	Date Sampled
	9/75
Arsenic (As), (UG/L):	1
Boron (B), (UG/L):	870
Cadium (Cd), (UG/L):	0
Calcium (Ca), (MG/L):	440
Chloride (Cl), (MG/L):	9,600
Fluoride (F), (MG/L):	1.9
Iron (Fe), (UG/L):	80
Lithium (Li), (UG/L):	670
Magnesium (Mg), (MG/L):	40
Manganese (Mn), (UG/L):	70
Mercury (Hg), (UG/L):	0
Nitrogen (N), (MG/L):	0.01
Phosphate (PO ₄)	
Ortho diss. as P, (MG/L):	0.03
Ortho, (MG/L):	0.09
Potassium (K), (MG/L):	150
Selenium (Se), (UG/L):	0
Silica (SiO ₂), (MG/L):	28
Sodium (Na), (MG/L):	6,300
Sulfate (SO ₄), (MG/L):	1,100
Zinc (Zn), (UG/L):	20
Alkalinity	
As Calcium Carbonate, (MG/L):	610
As Bicarbonate, (MG/L):	744
Hardness	
Noncarbonate, (MG/L):	650
Total, (MG/L):	1,300
Specific conductance (Micromohs):	31,000
Total dissolved solids (TDS), (MG/L):	18,000
pH, Field	6.7
Discharge (gpm):	5E
Temperature (°C):	50

Remarks: Located on north side of Colorado River

Table 1. Physical Properties and Chemical Analysis of Thermal Waters in Colorado.

Glenwood Springs Area: Spring C

Location: $39^{\circ}32'02''$ N. Latitude; $107^{\circ}19'02''$ W. Longitude; T. 6 S., R. 89 W., Sec. 10 cb, 6th P.M., Garfield County

Temperature: 46° C

Discharge: 2-3 gpm

Specific conductance:--

Remarks: Located 170 feet east of siphon pipe on south side of Colorado River.

Table 1. Physical Properties and Chemical Analysis of Thermal Waters in Colorado.

Glenwood Springs Area: Railroad Spring*

Location: 39°33'16"N. Latitude; 107°18'51"W. Longitude; T. 6 S., R. 88 W., Sec. 10 bab, 6th. P.M., Garfield County

	Date Sampled	
	1/76	4/76
Arsenic (As), (UG/L):	-	-
Boron (B), (UG/L):	850	890
Cadium (Cd), (UG/L):	-	-
Calcium (Ca), (MG/L):	460	460
Chloride (Cl), (MG/L):	10,000	10,000
Fluoride (F), (MG/L):	2.4	2.1
Iron (Fe), (UG/L):	20	40
Lithium (Li), (UG/L):	-	-
Magnesium (Mg), (MG/L):	80	86
Manganese (Mn), (UG/L):	70	80
Mercury (Hg), (UG/L):	-	-
Nitrogen (N), (MG/L):	0.01	0.01
Phosphate (PO ₄)		
Ortho diss. as P, (MG/L):	0.04	0.04
Ortho, (MG/L):	0.12	0.12
Potassium (K), (MG/L):	200	180
Selenium (Se), (UG/L):	-	-
Silica (SiO ₂), (MG/L):	29	29
Sodium (Na), (MG/L):	6,100	6,200
Sulfate (SO ₄), (MG/L):	1,100	880
Zinc (Zn), (UG/L):	-	-
Alkalinity		
As Calcium Carbonate, (MG/L):	636	627
As Bicarbonate, (MG/L):	775	764
Hardness		
Noncarbonate, (MG/L):	840	880
Total, (MG/L):	1,500	1,500
Specific conductance (Micromohs):	30,500	29,900
Total dissolved solids (TDS), (MG/L):	18,400	18,200
pH, Field	7.1	6.5
Discharge (gpm):	75	75
Temperature (°C):	51	51

* Remarks: Located on south side of Colorado River west of railroad tunnel.

Table 1. Physical Properties and Chemical Analysis of Thermal Waters in Colorado.

Wenwood Springs Area: Spring A*

Location: 39°32'58"N. Latitude; 107°19'10"W. Longitude; T. 6 S., R. 89 W., Sec. 9 bb, 6th. P.M., Garfield County

	Date Sampled	
	7/75	
Arsenic (As), (UG/L):	0	
Boron (B), (UG/L):	800	
Cadmium (Cd), (UG/L):	0	
Calcium (Ca), (MG/L):	410	
Chloride (Cl), (MG/L):	9,600	
Fluoride (F), (MG/L):	2.2	
Iron (Fe), (UG/L):	40	
Lithium (Li), (UG/L):	730	
Magnesium (Mg), (MG/L):	88	
Manganese (Mn), (UG/L):	70	
Mercury (Hg), (UG/L):	0	
Nitrogen (N), (MG/L):	0.01	
Phosphate (PO ₄)		
Ortho diss. as P, (MG/L):	0.03	
Ortho, (MG/L):	0.09	
Potassium (K), (MG/L):	160	
Selenium (Se), (UG/L):	0	
Silica (SiO ₂), (MG/L):	30	
Sodium (Na), (MG/L):	6,000	
Sulfate (SO ₄), (MG/L):	980	
Zinc (Zn), (UG/L):	20	
Alkalinity		
As Calcium Carbonate, (MG/L):	604	
As Bicarbonate, (MG/L):	736	
Hardness		
Noncarbonate, (MG/L):	780	
Total, (MG/L):	1,400	
Specific conductance (Micromohs):	31,000	
Total dissolved solids (TDS), (MG/L):	17,600	
pH, Field	6.3	
Discharge (gpm):	2-3E	*Remarks: Located on south side of Colorado River 27 feet west of siphon.
Temperature (°C):	44	

Table 1. Physical Properties and Chemical Analysis of Thermal Waters in Colorado.

Glenwood Springs Area: Spring B *

Location: 39°33'02"N. Latitude; 107°19'04"W. Longitude; T. 6 S., R. 89 W., Sec. 10 cb, 6th. P.M., Garfield County

	Date Sampled			
	7/75	10/75	1/76	4/76
Arsenic (As), (UG/L):	0	1	-	-
Boron (B), (UG/L):	760	830	840	840
Cadium (Cd), (UG/L):	0	0	-	-
Calcium (Ca), (MG/L):	450	490	49	360
Chloride (Cl), (MG/L):	9,900	9,800	9,500	9,500
Fluoride (F), (MG/L):	2.1	2.3	2.1	2.1
Iron (Fe), (UG/L):	30	60	30	40
Lithium (Li), (UG/L):	800	860	-	-
Magnesium (Mg), (MG/L):	86	79	76	86
Manganese (Mn), (UG/L):	70	70	70	60
Mercury (Hg), (UG/L):	0	0	-	-
Nitrogen (N), (MG/L):	0.02	0.18	0.01	0
Phosphate (PO ₄)				
Ortho diss. as P, (MG/L):	0.01	0.03	0.04	0.04
Ortho, (MG/L):	0.03	0.09	0.12	0.12
Potassium (K), (MG/L):	170	160	190	170
Selenium (Se), (UG/L):	0	0	-	-
Silica (SiO ₂), (MG/L):	30	27	28	28
Sodium (Na), (MG/L):	6,300	6,400	6,500	6,300
Sulfate (SO ₄), (MG/L):	1,000	1,100	1,000	990
Zinc (Zn), (UG/L):	20	20	-	-
Alkalinity				
As Calcium Carbonate, (MG/L):	613	617	614	612
As Bicarbonate, (MG/L):	747	752	749	746
Hardness				
Noncarbonate, (MG/L):	870	930	0	640
Total, (MG/L):	1,500	1,600	440	1,300
Specific conductance (Micromohs):	35,000	31,000	29,100	29,700
Total dissolved solids (TDS), (MG/L):	18,300	18,400	17,700	17,800
pH, Field	6.5	7.0	6.7	7.0
Discharge (gpm):	75	75	100	110
Temperature (°C):	51	50	51	51

* Remarks: Located on south side of Colorado River 27 feet west of siphon.

Table 1. Physical Properties and Chemical Analysis of Thermal Waters in Colorado.

Glenwood Springs Area: Spring D*

Location: 39°33'05"N Latitude; 107°19'00"W. Longitude; T. 6 S., R. 89 W., Sec. 10 cb, 6th. P.M., Garfield County

	Date Sampled	
	7/75	
Arsenic (As), (UG/L):	0	
Boron (B), (UG/L):	810	
Cadium (Cd), (UG/L):	0	
Calcium (Ca), (MG/L):	450	
Chloride (Cl ⁻), (MG/L):	9,800	
Fluoride (F), (MG/L):	2.1	
Iron (Fe), (UG/L):	30	
Lithium (Li), (UG/L):	800	
Magnesium (Mg), (MG/L):	82	
Manganese (Mn), (UG/L):	70	
Mercury (Hg), (UG/L):	0	
Nitrogen (N), (MG/L):	0.01	
Phosphate (PO ₄)		
Ortho diss. as P, (MG/L):	0.03	
Ortho, (MG/L):	0.09	
Potassium (K), (MG/L):	160	
Selenium (Se), (UG/L):	0	
Silica (SiO ₂), (MG/L):	30	
Sodium (Na), (MG/L):	89	
Sulfate (SO ₄), (MG/L):	1,000	
Zinc (Zn), (UG/L):	10	
Alkalinity		
As Calcium Carbonate, (MG/L):	611	
As Bicarbonate, (MG/L):	745	
Hardness		
Noncarbonate, (MG/L):	850	
Total, (MG/L):	1,500	
Specific conductance (Micromohs):~	36,000	
Total dissolved solids (TDS), (MG/L):	18,000	
pH, Field	6.4	
Discharge (gpm):	74	*Remarks: Located on south side of Colorado River 225 feet east of siphon.
Temperature (°C):	50	

Table 1. Physical Properties and Chemical Analysis of Thermal Waters in Colorado.

Glenwood Springs Area: Graves Spring

Location: 39°33'14"N. Latitude; 107°20'08"W. Longitude; T. 6 S., R. 89 W., Sec. 9 bb, 6th. P.M., Garfield County

	Date Sampled
	9/75
Arsenic (As), (UG/L):	0
Boron (B), (UG/L):	1,000
Cadium (Cd), (UG/L):	0
Calcium (Ca), (MG/L):	770
Chloride (Cl), (MG/L):	11,000
Fluoride (F), (MG/L):	2.9
Iron (Fe), (UG/L):	70
Lithium (Li), (UG/L):	690
Magnesium (Mg), (MG/L):	150
Manganese (Mn), (UG/L):	50
Mercury (Hg), (UG/L):	0
Nitrogen (N), (MG/L):	0.04
Phosphate (PO ₄)	
Ortho diss. as P, (MG/L):	0.05
Ortho, (MG/L):	0.15
Potassium (K), (MG/L):	180
Selenium (Se), (UG/L):	0
Silica (SiO ₂), (MG/L):	32
Sodium (Na), (MG/L):	7,000
Sulfate (SO ₄), (MG/L):	2,000
Zinc (Zn), (UG/L):	20
Alkalinity	
As Calcium Carbonate, (MG/L):	610
As Bicarbonate, (MG/L):	744
Hardness	
Noncarbonate, (MG/L):	1,900
Total, (MG/L):	2,500
Specific conductance (Micromohs):	33,500
Total dissolved solids (TDS), (MG/L):	21,500
pH, Field	7.0
Discharge (gpm):	5
Temperature (°C):	46
Remarks: Located at 0281 164 Road in Glenwood Springs.	

Table 1. Physical Properties and Chemical Analysis of Thermal Waters in Colorado.

Glenwood Springs Area: Drinking Spring

Location: 39°32'59"N. Latitude; 107°19'19"W. Longitude; T. 6 S., R. 89 W., Sec. 9 ad, 6th P.M., Garfield County

	Date Sampled			
	7/75	10/75	1/76	4/76
Arsenic (As), (UG/L):	1	1	-	-
Boron (B), (UG/L):	910	880	920	870
Cadium (Cd), (UG/L):	0	0	-	-
Calcium (Ca), (MG/L):	510	530	500	480
Chloride (Cl), (MG/L):	11,000	11,000	11,000	10,000
Fluoride (F), (MG/L):	2.3	2.0	2.7	2.2
Iron (Fe), (UG/L):	20	150	20	40
Lithium (Li), (UG/L):	810	900	-	-
Magnesium (Mg), (MG/L):	90	88	82	15
Manganese (Mn), (UG/L):	80	90	70	60
Mercury (Hg), (UG/L):	0	0	-	-
Nitrogen (N), (MG/L):	0.01	0	0.01	0.01
Phosphate (PO ₄)				
Ortho diss. as P, (MG/L):	0.03	0.05	0.06	0.05
Ortho, (MG/L):	0.09	0.15	0.18	0.15
Potassium (K), (MG/L):	180	170	380	180
Selenium (Se), (UG/L):	0	0	-	-
Silica (SiO ₂), (MG/L):	32	29	30	30
Sodium (Na), (MG/L):	7,000	6,900	7,000	6,600
Sulfate (SO ₄), (MG/L):	1,100	1,100	1,100	1,100
Zinc (Zn), (UG/L):	20	10	-	-
Alkalinity				
As Calcium Carbonate, (MG/L):	638	637	634	633
As Bicarbonate, (MG/L):	778	777	773	772
Hardness				
Noncarbonate, (MG/L):	1,000	1,000	950	630
Total, (MG/L):	1,600	1,700	1,600	1,300
Specific conductance (Micromohs):	36,800	30,100	31,100	30,000
Total dissolved solids (TDS), (MG/L):	20,300	20,200	20,500	18,800
pH, Field	6.3	6.5	6.4	6.4
Discharge (gpm):	-	-	161	140
Temperature (°C):	50	50	51	51

Remarks: Located approx. 100 feet east of pool.

Table 1. Physical Properties and Chemical Analysis of Thermal Waters in Colorado.

Glenwood Springs Area: Big Spring (feeds swimming pool)

Location: 39°32'59"N. Latitude; 107°19'18"W. Longitude; T. 6 S., R. 89 W., Sec. 9 ad, 6th. P.M., Garfield County

	Date Sampled
	7/75
Arsenic (As), (UG/L):	0
Boron (B), (UG/L):	890
Cadium (Cd), (UG/L):	0
Calcium (Ca), (MG/L):	510
Chloride (Cl), (MG/L):	11,000
Fluoride (F), (MG/L):	2.3
Iron (Fe), (UG/L):	60
Lithium (Li), (UG/L):	800
Magnesium (Mg), (MG/L):	91
Manganese (Mn), (UG/L):	80
Mercury (Hg), (UG/L):	0
Nitrogen (N), (MG/L):	0.01
Phosphate (PO ₄)	
Ortho diss. as P, (MG/L):	0.04
Ortho, (MG/L):	0.12
Potassium (K), (MG/L):	180
Selenium (Se), (UG/L):	0
Silica (SiO ₂), (MG/L):	32
Sodium (Na), (MG/L):	6,900
Sulfate (SO ₄), (MG/L):	1,100
Zinc (Zn), (UG/L):	30
Alkalinity	
As Calcium Carbonate, (MG/L):	634
As Bicarbonate, (MG/L):	773
Hardness	
Noncarbonate, (MG/L):	1,000
Total, (MG/L):	1,600
Specific conductance (Micromohs):	36,800
Total dissolved solids (TDS), (MG/L):	20,200
pH, Field	6.3
Discharge (gpm):	2,263
Temperature (°C):	50

Remarks: Located on north side of Colorado River.

Appendix B

Influence of Temperature and T.D.S.
Upon An Aquaculture System for Sew-
age Treatment Combined with Geother-
mal Water at Glenwood Springs, Colorado.

for the

University of Denver

by the

Applied Aquatic Resources Institute

P.O. Box 815

Encinitas, CA 92024

(714) 436-2911

I. Introduction

A system for enhanced sewage treatment using an aquaculture system at elevated temperature has been suggested for the municipality of Glenwood Springs, Colorado. The system is to derive heat from spent geothermal water that is mixed with sewage prior to introduction into aquaculture cells. The effluent from the aquaculture cells is to be of a quality suitable for discharge into surface water or shallow aquifers.

The nature of geothermal water is such that its addition to an aquaculture system will create impacts from the temperature, dissolved solids content and volume flow rate from the geothermal source. The purpose of this report is to discuss these impacts, specifically the effects of dilution, temperature, and dissolved substances upon the aquaculture system to be used for wastewater treatment and conversely the effect of an aquaculture system on temperature and dissolved substances related to meeting discharge criteria.

II. Nature of Geothermal Water

The composition of geothermal water is governed by its temperature, the lithology of the rock with which it has had contact, and the extent to which it is mixed with meteoric water or geothermal waters of distinctly different initial composition (Fournier et al, 1980).

Water in contact with igneous rocks is nearly saturated with silica at reservoir temperature because of its equilibrium with quartz. Also, temperature dependent equilibria involving feldspars, micas and accessory minerals govern the Na, K, and Ca concentrations in geothermal water. If a geothermal reservoir is known to involve a simple igneous or metamorphic lithology the silica content and Na, K, and Ca concentrations can be used to estimate reservoir temperature because the relationships between concentration and temperature is predictable from considerations

of chemical equilibrium (Fournier, 1979). However, if the reservoir lithology is complex (e.g., includes limestones or evaporites as well as igneous rocks) or if meteoric water bearing dissolved CO_2 mixes with geothermal water of deeper origin, the relationship between temperature and concentrations of dissolved ions is not readily estimated; high TDS content can exist in relatively cool geothermal water in such cases. Some examples of the effect of lithology upon the concentration of dissolved ions in geothermal water of nearly the same temperatures are shown in the attached Table. Only major ionic constituents are presented in the Table as these are most representative of the total dissolved salt (TDS) content of the water.

The ionic composition of the geothermal water at Glenwood Springs, Colorado, seems to resemble that of a slightly diluted sea water (see attached Table). Its composition is more similar to water from the California and Mexico sedimentary rock province than to water from igneous provinces. It is characterized by low temperature ($60^\circ\text{--}82^\circ\text{C}$) and high TDS (20,000 mg/l) particularly contributed by monovalent ions. Further, it is relatively low in silica and high in boron. For study purposes the discharge of this geothermal water is estimated to be from 1900-5700 liters/min or $2.7\text{--}8.1 \times 10^3 \text{ m}^3/\text{d}$ (500-1500 gpm 0.7 to 2 mgd).

III. Nature Of Wastewater

The composition of municipal wastewater (sewage) is influenced by the original composition of water from the municipal supply (Pound and Crites, 1973). In the U.S.A., the TDS content of water supply ranges from 10 to over 1000 mg/l but most values are below 500. TDS values in Southern California are about 700 mg/l where the Colorado River serves as a major water supply (Durfor and Becker, 1965).

Passage of municipal water through the sewage system imparts added TDS (mostly from water softeners) suspended solids, nutrients (N and P), microorganisms and organic compounds that exert a biochemical oxygen demand, industrial chemicals and heavy metals in varying amounts depending upon demography.

In Glenwood Springs, the TDS of municipal sewage is approximately 350 to 450 mg/l. In most municipalities, raw sewage contains enough nutrients to permit the application of biological wastewater treatment techniques such as aquaculture. Concentrations of other constituents in the sewage are seldom at levels toxic to biological systems except for short episodes.

The temperature of municipal wastewater varies according to the nature of sewage treatment. Usually, it is not far removed from an average of 10°C (50°F). The temperature of the influent wastewater at Glenwood Springs is reported to range from 10°C (47°F) in the winter to 13°C (55°F) in the summer. However, during the summer the wastewater stream picks up heat from the environment and approaches the thermal discharge limit of 21°C (70°F).

The current discharge of wastewater is about 3406 m³/d (0.9 mgd) with a projected ultimate increase to 7570 m³/d (2 mgd).

IV. Aquaculture Treatment Alternatives

Numerous kinds of aquaculture systems can be used in conjunction with a combined geothermal and municipal wastewater stream for treatment. Recent reviews by Duffer & Moyer (1978), Tortell (1978), and Alsten (1979) enumerates these systems and their current operational and research status.

Aquaculture systems for wastewater treatment can be divided up into; natural and artificial wetland processes (marshes, etc.), finfish systems, macrophyte systems, invertebrates systems and integrated systems. All can theoretically be designed to handle a mixture of sewage and geothermal water. However the large land area required by finfish and to a certain extent wetland systems, approximately 3.2 ha/1000 m³ (30 acres/MGD) to meet secondary treatment standards with its concomitant large thermal loss, may negate a great deal of the possible thermal enhancement due to the geothermal contribution. At the same

time, certain salt marsh species (discussed later) tolerate and even take up high levels of T.D.S., a major concern and impediment to the discharge of wastewater diluted geothermal effluent. A compact, highly controlled artificial wetland such as that reported on by Small (1976) might be effective if the T.D.S. uptake could be enhanced significantly so that discharge criteria could be met.

Macrophytic systems, especially those using the tropical plant water hyacinth (Eichornia crassipes), use substantially smaller land areas, approximately 1.28 ha/1000 m³/d (12 acres/MGD), however, water hyacinths cannot sustain salinities greater than about 2500 mg/l T.D.S. (Haller, et al, 1974). Although duckweed (Lemna spp.) and other aquatic plants can withstand elevated salinities and temperatures, they have not been shown to be as effective as water hyacinths to date for wastewater treatment.

Several interesting pilot systems intentionally using invertebrates for wastewater treatment (as any good oxidation pond will have invertebrates as well as algae) have been studied (Dinges 1976, McLarney & Sherman, 1976). The most significant work regarding this potential application is Goldman and Ryther's (1976) system, mixing sewage in seawater and culturing various organisms including shellfish. There is little doubt that appropriate food chain organisms can be found to effectively treat the wastewater - geothermal mixture but invertebrate culture systems are generally unstable and none have yet been scaled up to operational systems (Duffer & Moyer, 1978).

Integrated systems overcome many of the instability problems by creating dynamic interrelationships between different organisms and trophic levels involved in the wastewater treatment process. One good example of this is the Solar AquaCell system where plastic artificial physical substrate is submerged in a multicell lagoon system (Serfling & Alsten, 1978, Stewart & Serfling, 1979). This becomes the site of bacterial and algae growth (akin to a submerged trickling filter) to ab- and absorb nutrients and suspended solids. Rotifers, ciliates and

a grazing population of invertebrates, amphipods, snails, etc., control the biomass of the bacterial community.

Macrophytes, usually both water hyacinths and duckweed, cover the lagoon surface. The extended root mass of Eichhornia also serves as a physical substrate for invertebrate detritivores which are harvested out with the macrophytes. This lagoon system requires approximately .1 ha/1000 m³ (one acre/MGD) to reach secondary treatment levels in southern latitudes when covered with a greenhouse to enhance heat absorption and retention. Since process temperature is already considered sufficiently significant to justify the cost of a greenhouse cover, this system may be applicable to a geothermally enhanced wastewater treatment system.

Trickling filters have been used effectively in tropical areas with seawater flush systems and appropriate detritivores (ostracods gastropods, etc.) can be used in the saline environment resulting from the combining of geothermal and municipal wastewaters. The replacement of water hyacinths with more salt tolerant Lemna spp. or sea macrophytes such as Ulva or Gracilaria could make this a good candidate system for Glenwood Springs.

It should be noted that although geothermal heat is being used to enhance aquacultural production in a few instances, no applications of geothermally enhanced municipal wastewater treatment using aquaculture have yet taken place.

V. Effects Of Mixing Geothermal Water With Municipal Wastewater

The concept of using waste heat from spent geothermal water to promote aquaculture-based wastewater treatment is limited by the properties of the waters being mixed and by the properties of the produced water as regards water discharge regulations.

It is well known that elevated temperatures up to a point, can enhance the tempo of biological processes. Mara (1976) outlines some of

the advantages and difficulties involved in tropical wastewater treatment systems. For the most part these systems are simple waste stabilization ponds or algae lagoons. A general rule is that for every 10°C increase in temperature, within certain limits, biological kinetics double (Barnes, 1937). The most extensive work in high temperature wastewater treatment has been done by the Paper Industry and has verified this empirical formula in this specific application (NCASI, 1978).

In the aquatic environment other factors enter into evaluation of the limits of this empirical equation to determine the optimal temperature for wastewater treatment. Chief among these is the lower solubility of oxygen in water as temperature rises. In simple algae lagoons used in most tropical areas this lowered O_2 solubility is to a certain extent naturally offset by the increased oxygen generated due to higher photosynthetic metabolism. However, the long retention times (30-60 days) of such systems require a large land area. Aerated ponds overcome this large land requirement by mechanically aerating which requires an energy input. Detention times are normally less than 10 days for aerated lagoons.

Dilution of wastewater (WW) by geothermal water (GTW) affects the temperature of operation of the aquaculture unit and the temperature of the discharged effluent. The effect of dilution follows the ideal relationship:

$$T_D = (T_G V_G + T_W V_W) \text{ where}$$

T = Temperature

V = Volume flow rate

Subscripts: D = discharge; G = geothermal; and

W = wastewater.

Given the summer water temperature and flow conditions prevailing at Glenwood Springs ($T_G = 60^\circ\text{C}$ (150°F), $V_G = 5110 \text{ m}^3/\text{d}$ (1.35 mgd), $T_W = 10^\circ\text{C}$ (55°F), $V_W = 3406 \text{ m}^3/\text{d}$ (9 mgd)), the discharge temperature should

be 36°C (104°F), clearly in excess of the 21°C (70°F) maximum discharge temperature stipulated by regulations, not to mention being above the optimum temperature for aquaculture which is about 29-32°C (85-90°F) depending on the species involved.

Optimum aquaculture temperature would be achieved by maintaining GTW flow at about 1893 m³/d (0.5 mdg). In such a case, the produced water would have to be cooled about 10°C (20°F) before discharging it to surface waters unless discharge criteria could be changed. This cooling could be accomplished more easily during the winter than during the summer, but in either case evaporative cooling would increase TDS which is the most significant obstacle to surface discharge.

Assuming the conditions extant at Glenwood Springs, raising the wastewater temperatures in an aerated biological/aquacultural wastewater treatment system from 10°C (50°F) to approximately 30°C (88°F) would increase power required for aeration by about 25% while it would nominally reduce retention time and land area by about 50%.

The dilution equation for nutrients and dissolved substances is similar to the temperature dilution equation:

$$C_D = (C_G V_G + C_W V_W) / (V_G + V_W) \text{ where}$$

C refers to concentration and the other symbols remain as before. In the case of nutrients, C = 0 and the dilution equation can be linearized:

$$\ln C_D = \ln(V_W V_W) - \ln(V_G + V_W)$$

Using flow values pertaining to Glenwood Springs, the equation becomes:

$$\ln C_D = \ln C_W - 0.58 \text{ or}$$

$C_D = 0.56 C_W$, that is, the nutrient levels entering the aquaculture system would be about half that of those in the municipal sewage. However, if the flow of geothermal water is adjusted to maintain an optimum (30°C) temperature in the aquaculture system, the dilution equation

yields nutrient levels of

$C_D = 0.62 C_W$ (i.e., almost 2/3 the level of nutrients in the municipal sewage) entering the aquaculture system. It appears that at this level, dilution has no adverse impact upon temperature or nutrient levels in the GTW+WW aquaculture system.

If concentrations of boron and of heavy metals in the municipal wastewater are assumed to be negligible compared to the concentrations in GTW, the dilution equation is:

$$\ln C_D = \ln C_G + \ln V_G - \ln (V_G + V_W)$$

At flows that maintain optimum aquaculture temperature, the equation yields:

$$\begin{aligned}\ln(C_D/D_G) &= 0.74 \\ C_D &= 0.48C_G.\end{aligned}$$

Such dilution reduces the boron concentration entering the aquaculture system to about 0.4 mg/l which is about half of the maximum permitted for agricultural reuse (0.75 mg/l) in Colorado (Colorado Department of Health, 1979). Presumably, the heavy metals would behave as indicated by Fe and Mn and be diluted to levels well below the maximum values permitted by discharge regulations (Ayers and Westcot, 1976).

The extremely high TDS level in GTW presents a serious obstacle to the use of GTW to maintain optimum temperatures in an aquaculture based system for waste water treatment at Glenwood Springs. The dilution of TDS achieved at optimum aquaculture temperature is:

$$(TDS)_D = (20,000(.56) + 350 (.9))/1.46 = 7887\text{mg/l}$$

This level is about ten times the levels of TDS permitted for discharge water (700-1,000 mg/l). It is evident that TDS is a critical factor in the application of aquaculture to wastewater treatment in Glenwood Springs just as it is in Southern California. The excessive TDS levels in the GTW at Glenwood Springs are especially deleterious because about half of the TDS is chloride ion.

VI. Ameliorative Measures for Meeting Discharge Criteria

Control of the temperature of treated wastewater from an aquaculture system can be achieved by blending GTW and WW to maintain 27° to 32°C (80 - 90°F) in the treatment then cooling the effluent about 5-10°C prior to discharge to surface waters.

Nutrient levels are maintained well below maxima stipulated by regulations inasmuch as the nutrients are converted to harvestable biomass in the system. Concentrations of heavy metals, phenols and other organic compounds are maintained at permissible levels by metabolic and chemical processes within aquaculture systems in use. The uptake rates, tolerance, and lethal limits for the various chemicals in wastewater by the members of the biota in an aquaculture system are not known in complete detail. However, much fragmentary information is available (see bibliography) should it be necessary to design an aquaculture biota to accommodate dissolved chemicals particular to a geographic location.

The control of TDS in the effluent from an aquaculture wastewater treatment is not part of the state-of-the-art design of such systems. Means of reducing evaporation from wastewater are incorporated in aquaculture to minimize TDS increase but no part of the aquaculture system is included for the express purpose of reducing TDS in the effluent (Serfling & Alsten, 1978). Nevertheless, reports (Dinges, 1973, 1976) of remarkable TDS reduction in an aquaculture wastewater

treatment system suggest that TDS control and reduction might be incorporated into aquaculture system design.

VII. Potential for Reducing TDS Using Aquatic Plants

The use of aquatic plants for reducing the TDS of wastewater is possible only if certain requirements are met:

1. The plants must accumulate TDS ions in harvestable tissue or else cause TDS ions to be bound in a settleable solid phase.
2. The plants must have a combined growth rate of TDS ion uptake rate sufficient to cause adequate rate of reduction of TDS.
3. The growth (and uptake) rate must be constant year around rather than dropping during a period of dormancy.
4. The plant should perform equally well over a range of TDS, Hardness and Alkalinities that includes a substantial part of the range of these parameters found in municipal, industrial or agricultural wastewaters.
5. The plant should be tolerant of rates of harvest sufficient to achieve maximum removal of TDS ions.

These requirements carry implications regarding the nature of the plants that could be used for TDS reduction. The plants must be aquatic in the sense that they are obligate or facultative aquatic macrophytes or algae. Any plants capable of being raised hydroponically should be considered to be aquatic in the context of aquaculture-based wastewater treatment.

The plant should be a tropical perennial exhibiting continuous growth all year. The perennial should withstand severe, repeated

cropping. Alternatively, a rapid growing annual, for example, a desert annual, could serve as well. Year round growth could be achieved if annuals from both the North and South Hemispheres are used in pairs. The plants must be halophytic or be euryhaline in their tolerance to TDS ions and they must possess physiological mechanisms for accumulating TDS ions, e.g., by assimilation and translocation to leaves where storage occurs, or by generating sloughed tissue that forms a substrate for cation sorption, chelation or other sequestering process.

Removal of TDS Ions

Certain theoretical limitations determine the feasibility of TDS removal by plants. The amount of wastewater TDS improvement (I) is the difference between the TDS content of influent wastewater and that of the discharge of the aquaculture unit. The rate of TDS improvement in a wastewater stream having a volume flow rate (F) is IF. The volume (V) of the aquaculture unit can be adjusted to fix the detention time (T) because $T = V/F$. (1)

The values of the variables are determined by the rate (R) of removal (expressed as mass/area/time) of TDS ions by the aquaculture plants according to the following relationships: The area (A) of the aquaculture unit is

$$A = IF/R \quad (2)$$

The minimum depth (D) of the aquaculture unit is fixed by the nature of the roots or other structure of the plants used in the unit. The depth can be expressed $D = V/A$ (3)

$$\text{or } D = VR/IF \quad (4)$$

Hence, the rate (R) of removal of TDS ions is

$$R = DIF/V \quad (5)$$

and the detention time (T) is

$$T=DI/R \quad (6)$$

The feasibility of TDS reduction by aquaculture can be tested by evaluating the variables above for a typical case. Assume that we wish to reduce the TDS of wastewater from 1300 mg/l to 400 mg/l. Then, since $1 \text{ mg/l} = 1 \text{ g/M}^3$, $I=900 \text{ g/M}^3$. Further, assume that the plants used in the aquaculture unit permit a water depth (D) of 1 meter. $D=1\text{M}$. Let us calculate the rate (R) of TDS removal required of the plants. Equation (6), rearranged, yields

$$R=DI/T \quad (7)$$

which, evaluated for our typical case, is

$$R=900/T \text{ g/M}^2/\text{day}$$

where T is in units of days. This expression states that the required removal rate for producing a 900 mg/l improvement in TDS is $900/T \text{ g/M}^2/\text{day}$.

In order to see if plants are capable of such TDS removal rates, we must examine the removal process in more detail. Croppable plants regenerate biomass at some maximum sustained yield expressible on a dry weight basis, as an average production rate (P) in $\text{g/M}^2/\text{yr}$. Ideally, production should be nearly constant all year. The uptake and accumulation of TDS ions in plant tissue is reflected by their ash content (S). The TDS removal rate then is the product (PS) of the ash percentage and the production rate for the plants. Although ash content data is usually available for plants of interest, the continuous production rate (maximum sustained yield from cropping) usually is not. Instead, the total annual biomass production (B) under native or laboratory conditions is reported. It appears necessary to derive values for a factor (f) that

represents the fraction of growth available for continuous harvesting. Then $P=fB$ would express the rate of production.

Production of plant biomass has an average value of about 1000 $\text{g/M}^2/\text{yr}$ and a range of values from 250 to 2000 $\text{g/M}^2/\text{year}$. Ash contents of plants range between 2 and 20%.

This means that the annual uptake (SB) of TDS ions associated with the growth of plants ranges from 5 to 400 $\text{g/M}^2/\text{yr}$ and averages between 10 and 200 $\text{g/M}^2/\text{yr}$. These values suggest that the base (minimum) uptake rate for plants is on the order of 1 $\text{g/M}^2/\text{day}$. It is evident that a minimum uptake rate based upon ordinary plants is too small (by about 2 orders of magnitude if a 10 day detention is considered) to permit practical TDS removal.

The rapidly growing aquatic macrophyte, water hyacinth, has a reported dry weight production value of 14825 $\text{g/M}^2/\text{yr}$ (Del Fosse, 1977). Assuming the ash content to be 20%, the value of removal rate of 2965 $\text{g/M}^2/\text{yr}$ (or 8 $\text{g/M}^2/\text{day}$) is indicated. The corresponding value of detention time is 111 days suggesting that the TDS removal by water hyacinth reported by Dinges (1973 and 1976) was not by metabolic uptake alone.

Duckweed is reported (Hillman and Culley, 1978) to have an annual production of 1760 g/M^2 and an ash content of 11%. This means the TDS removal rate of duckweed is 0.48 $\text{g/M}^2/\text{day}$. Likewise, this rate is about 2 orders of magnitude too small to be practical.

Neither water hyacinth nor duckweed are adapted to tolerate or accommodate elevated salinity; no mechanism for excluding or storing TDS ions is reported on these plants.

Salt tolerance of water hyacinths is low, however, the toxic level reported varies between investigators. Penfound & Earle (1948) report that water hyacinths do not occur in streams or lakes with an average

salinity greater than 15% of sea water (2900 mg/L chloride). Haller et al (1974) reported that sea water salinity levels of 1.66% (900 mg/L Cl) and 2.5% (1300 mg/L Cl) reduced growth 15 and 38% respectively, over a 4 week period. Water hyacinths have been shown to take up numerous other chemicals constituents (Robinson et. al. 1976, Wolverton, 1978) that might be of concern in geothermal waters, and would not seem to be toxic. The chloride level at Glenwood Springs is significantly toxic and would need to be diluted approximately 8 to 1 to maintain a healthy and productive water hyacinth culture. Assuming 3400 M³/d (.9 mgd) of wastewater this would reduce the GTW to 425 M³/d (.1125 mgd) and yield a thermal enhancement of only 5°C. Salinity values of up to 3300 ppm has been shown to enhance growth of Lemna species while levels in excess of 16,650 are toxic. (Haller et. al., 1974). However, productivity of Lemna is much less than that for water hyacinths. Therefore, its role in wastewater treatment is significantly smaller as well as its overall potential to lower the TDS content of the water. Benemann (Pers. Comm., 1980) and others have considered the potential for salt removal using microalgae or marine plants and consider the latter "hopeless" and the former nearly so.

Halophytic plants, on the other hand, do possess mechanisms for taking up and storing salts. The reason is that the higher aquatic plants adapted to a fresh water habitat from terrestrial origins. Only those capable of accommodating the invasion of salts into their tissue were able to adapt to saline water environments (Wetzel, 1975). Coastal salt marsh plants accommodate salts by one of three mechanisms. They are succulents that compensate salt uptake by water uptake, or they are salt secreting via glands, or they accumulate salt in their leaves and discard it via leaf death (Chapman, 1976). The same mechanisms can be expected in halophytic plants in general, e.g. desert, or salt flat plants. One limitation, however, is the requirement of substantial amounts of potassium to take up sodium (about 3:1; Na:K) which is somewhat deficient in the Glenwood Springs GTW.

The mechanism of accumulation of salt in leaves is of interest because it suggests the possibility of finding or breeding halophytic

plants that have ash contents appreciably exceeding 20%. Beadle, et. al. (1957) and Ashby and Beadle (1957) have shown that members of the halophyte genus Atriplex can have ash contents from 30% to as high as 60%. Collander (1941) found high ash contents in the halophytic species of Salicornia and Plantago as well. If such plants were to grow rapidly and provide an appreciable production of harvestable tissue, they might be capable of substantial TDS reduction in wastewater.

To examine the potential of halophytes, we can calculate the TDS improvement under the best conditions we can expect. Assume that a halophyte can be found that grows as rapidly as water hyacinth and has comparable production, say $10 \text{ g/M}^2/\text{day}$.* Also assume that the ash content of the hypothetical halophyte is 80%, then the removal rate, R of this plant is $8 \text{ g/M}^2/\text{day}$. In an aquaculture unit 1 M deep, D treating a wastewater stream of 1 MGD ($3785 \text{ M}^3/\text{day}$), F , the maximum improvement, I in TDS that we can expect is $I=RT/D$ and assuming a detention time, T of 10 days, $I=80 \text{ mg/l}$. The area, A of the aquaculture unit required to achieve the TDS improvement would be $A=FT/D=3.8$ hectares (9.4 acres).

It is evident that about one tenth of the desired TDS improvement (900 mg/l) hypothetically could be achieved by halophytes. Improvement of TDS entirely by halophytes would require that their growth (actually production) be 10 times that of the more rapidly growing aquatic macrophytes.

Another mechanism for uptake and removal of TDS in wastewater appears to be the formation of some sort of complex or adsorbate between TDS ions and the products of decomposition of aquatic plant tissue. It seems likely that the remarkable improvement in TDS reported by Dinges (1973, 1976) was largely the result of such a mechanism which took place subsequent to the application of herbicide to a large standing crop of water

*This is about twice the value reported by Somers (1979) for one species of Atriplex.

hyacinths. It is assumed that those died and sank to become part of the decomposing benthic layer.* It is known that cellulose acts as a surface active substrate and that organic colloids can complex ions in a solution (Povoledo and Golterman, 1972). The humic acids, fulvic acid, humin and hylatomelanic acid (Schnitzer, 1972) are capable of forming metal complexes and chelates (Schnitzer and Khan, 1972). The divalent cations are complexed or adsorbed more readily than monovalent ions so it might be expected that TDS removal by this mechanism would be more effective in alkaline waters (Ca Mg) rather than saline waters (Na, K).

Little data is available regarding the stoichiometry of the formation of humic alkalai metal-cation complexes or of the sequestering of such cations by the coagulation of colloids, so the potential removal of TDS ions in natural waters or aquaculture systems is not known. Considering the potential TDS improvement that could be inherent in humic reactions, research to characterize TDS ion uptake by humic compounds is warranted. Rashid (1971) gives humic acid uptake of divalent Cu, Co & Ni as being on the order of 140 mg of metal per gram of humic acid. If we use this as a rough (order of magnitude) estimate of the ability of humic acids to sequester TDS cations, then about 9 g/l of humic acid is necessary to achieve a 900 mg/l improvement in TDS. Natural water rarely contains organic compounds in concentrations exceeding 20 mg/l (Rashid and Leonard, 1972). Clearly, one cannot expect the desired TDS improvement unless the system contains humic acids in concentrations 450 times as great as those found in nature. It does not appear that humic acids coagulation can account for the bulk of the TDS improvement reported by Dinges (1973). In fact, the improvement reported was 476 mg/l after removal of 73 mg/l by metabolism), so the removal rate of TDS ions must have been $54 \text{ g/M}^2/\text{day}$. This means that 540 g/M^2 of humic acid would

*Water hyacinths with removal rate of $8 \text{ g/M}^2/\text{day}$ will produce an improvement of 73 mg/l in a 0.9M ditch having a detention time of 8 days. This represents only 13% of the 549 mg/l mean improvement in TDS reported by Dinges (1973).

have to have been generated and coagulated every day. This could not have occurred since water hyacinths only produce a total of 40 g dry biomass/M²/day.

Another possibility for explaining Dinges' results lies in adsorption of TDS ions directly on the solid decomposition products of water hyacinths (cellulose, for example). Since 80% of the water hyacinth biomass is not ash, the maximum production of cellulose could have been about 32 g/M²/day. This implies that each gram cellulose is capable of adsorbing 1.7 g of TDS ions. Whether or not such a thing is possible will be the subject of important research. All these mechanisms were possibly involved and clarification of these interrelated reactions, uptake, humic sequestering and physical adsorption will be necessary to explain this potential demineralization process. Although Dinges (1973) observations were not of a highly controlled experimental nature, he did account for potential error due to rain.

Subsequent to rainfall, TDS values were not reduced as much as during the dry season. It is also significant to note that TDS is increased by evaporation especially during these dry periods and that evapotranspiration due to active hyacinth growth is 2 to 7 times that of free evaporation or approximately 3057-1220 liters/M²/year (6 to 24 acre/ft./per acre/year). (Del Fosse, 1977).

VIII. Summary

It should be clear that the mixing of geothermal and municipal water to enhance an aquaculture wastewater treatment system is not suitable for Glenwood Springs. The major constraint is meeting TDS discharge requirements due to the nature of the highly saline geothermal water.

An aquaculture wastewater treatment system enhanced with geothermal water might be more feasible in an area where geothermal waters are lower in salinity and thermal discharge criteria are flexible.

Several possible biological mechanisms for reducing TDS using aquatic plants and/or decomposing aquatic plants outlined previously, suggest fruitful areas of potentially valuable further research.

REFERENCES CITED

- Ashby, W. C. & N. C. W. Beadle. 1957. "Studies in Halophytes III, Salinity Factors in The Growth of Australian Saltbushes". Ecology, Vol. 38, No. 2, p. 344-352.
- Ayers, R. S. & D. W. Westcot. 1976. "Water Quality for Agriculture Irrigation & Drainage", paper #29. F.A.O. of the U.N., Rome. p. 7.
- Barnes, T. C. 1937. Textbook of General Physiology. Blakiston, Phil. p. 106-7.
- Beadle, N. C. W., R. D. B. Whalley, & J. B. Gibson. 1957 "Studies in Halophytes. II Analytic Data on the Mineral Constituents of Three Species of Atriplex and Their Accompanying Soils in Australia." Ecology, Vol. 38, No. 2, P. 340-344.
- Chapman, V. J. 1976. Coastal Vegetation. Pergamon Press, New york. P. 292.
- Colorado Dept. of Health, Water Quality Control Commission. 1979. "Regulations Establishing Basic Standards and an Antidegradation Standard and Establishing a System for Classifying State Water for Assigning Standards and for Granting Temporary Modifications". Adopted 22 May.
- Collander, R. 1941. "Selective Absorption of Cations by Higher Plants". Plant Physiology. Vol. 16, No. 4. Oct. p. 691-720.
- Del Fosse. 1977. "Water Hyacinth Biomass Yield Potentials." In Symposium Papers, Clean Fuels Form Biomass Wastes. Institute of Gas Technology, Chicago. January.
- Dinges, W. R. 1973. "Biological Demineralization of Water." Unpublished Report. Texas State Dept. of Health, Division of Wastewater Tech. and Surveillance.
- Dinges, W. R. 1976. "A proposed Integrated Biological Wastewater treatment system." Biological Control of Water Pollution. J. Tourbier and R. W. Pierson, Jr., eds. Phil, Pa. Univ., Penn. p. 225-230.
- Duffer, Wm. & J. E. Moyer. 1978. Municipal Wastewater Aquaculture. EPA Pub. No. 600/2078-110.
- Durfor, C. N. & E. Becker. 1964 (reprinted 1965). "Public Water Supplies of the 100 Largest Cities in the United States 1962." USGS Water Supply Paper 1912. U.S. Gov. Printing Office, Washington, D.C. 364 p.
- Fournier, R. O. 1979. "Geochemical & Hydrologic Considerations in the Prediction of Underground Conditions in Hot Springs Systems." J. Volcanol Geotherm. Res. Vol. 5. p. 1-16.

- Fournier, R. O. & J. M. Thompson & C. F. Austin. 1980. "Interpretation of Chemical Analyses of Waters Collected from Two Geothermal Wells at Coso, California." Journal of Geophysical Research. Vol. 85, No. B-5. May, p. 2405-2410.
- Goldman, J. D. & J. H. Ryther. 1976. "Waste Reclamation in an Integrated Food Chain System." In Biological Control of Water Pollution. J. Tourbien & R. W. Pierson, eds. Phil. Univ., Penn. p. 197-214.
- Haller, W. T., D. L. Sutton, & W. C. Barlowe. 1974. "Effects of Salinity on Growth of Several Aquatic Macrophytes." Ecology. Vol. 55, No. 4. p. 891-894.
- Hillman, Wm. & D. Culley, Jr. 1978. "The Uses of Duckweed" American Science. Vol. 66. July-August. p. 442-51.
- Kessick, M. A. & K. L. Machen. 1977. "Sea Water Domestic Waste Treatment." J. Water Poll. Control Fed. Vol. 48, No. 9. p. 2131-2136.
- McLarney, W. & M. Sherman. 1974. "Midge Culture at New Alchemy East." Aquaculture and the Fish Farmer. 1:10-13.
- Mara, Duncan. 1976. Sewage Treatment in Hot Climates. John Wiley & Sons.
- N.C.A.S.I. 1978. "The Effect of Temperatures on Treatment Plant Performance and Related Temperatures Studies." Stream Improvement Technical Bulletin. No. 312. Nat. Council of the Paper Ind. for Air & Stream Improvement, Inc. New York.
- Hentges, J. Jr. 1980. Personal Comm. V. F. Gainesville. August.
- Penfound, W. T. & T. T. Earle. 1948. The Biology of Water Hyacinth. Ecol. Mono. Vol. 18:447-478.
- Pound, C. E. & R. W. Crites. 1973. "Characteristics of Municipal Effluents." In Proceedings of the Joint Conference on Recycling Municipal Sludges & Effluents on Land. Univ. of Illinois. July, p. 49-61.
- Povoledo, D. & H. L. Golterman. 1975. "Humic Substances, Their Structure and Function in the Biosphere." Proceedings of an International Meeting Held at Nieuwersluis, The Netherlands, 29-31 May, 1972. Wageningen Center for Agricultural Publishing & Documentation. Wageningen. 368 p.
- Rashid, M. A. & J. Leonard. 1973. "Modifications in the Solubility and Precipitation Behavior of Various Metals as a Result of their Interaction with Sedimentary Humic Acid." Chem. Geol. Vol. 11. p. 89-97.

- Rashid, M. A. 1971. "Role of Humic Acids of Marine Origins and Their Different Molecular Weight Fractions in Complexing Di- and Tri-valent Metals." Soil Science. Vol. 111, No. 5. May, p. 298-306.
- Robinson, A. S. et al. 1976. "An Analysis of the Market Potential of Water Hyacinth - Based Systems for Municipal Wastewater Treatment." Battelle, L. C. NTIS #N76-23679/8wp.
- Schnitzer, M. 1973. "Chemical, Spectroscopic, & Thermal Methods for the Classification & Characterization of Humic Substances." Humic Substances, Their Structure & Function in the Biosphere. From Proceedings of International Meeting held at Nieuwirsuis, The Netherlands, May 29-31 in 1972. Ed. D. Poloredo & H. L. Golterman. Pub. Pudoe. Wageningen, p. 293-310. 368 pages.
- Schnitzer, M. & S. U. Khan. 1972. Humic Substances in the Environment. Marcel Dekker. N.Y. 327 p.
- Serfling, S. & C. Alsten. 1979. "An Integrated Controlled Environment Aquaculture Lagoon Process for Secondary or Advanced Wastewater Treatment." In E. J. Middlebrooks et al (eds) Performance and Upgrading of Wastewater Stabilization Ponds. EPA 600/9-79-011.
- Small, M. 1976. "Meadow-Marsh Systems as Sewage Treatment Plants." NTIS No. BNL 20757.
- Somers, G. Fred, Donna M. Grant & Ronal W. Smith. 1978. Domestication of Halophytes as Potential Crops for Food, Feed, or Marsh Improvement, Summary of Progress - 1976-1977. University of Delaware. Newark. December, p. 35.
- Stewart, W. & S. Serfling. 1979. "The Solar Aquacell System for Primary, Secondary or Advanced Treatment of Wastewaters." Presented at seminar on Aquaculture Systems for Wastewater Treatment. U. C. Davis. Sept. 11 & 12.
- Tortell, P. 1978. "The Utilization of Waste Nutrients for Aquaculture." Presented at the International Conf. on Dev. in Land Methods of Wastewater Treatment and Utilization, Melbourne, Australia, Oct. 23-27.
- Wetzel, R. G. 1975. Limnology. W. B. Saunders. Phil. p. 162-165. 743 pages.
- Wolverton, B. C. 1978. "Compiled Data on the Vascular Aquatic Plant Program: 1975-1977." NASA, NATL Station Miss. 148 p.
- Yoav, Waisel. 1972. Biology of Halophytes. Academic Press. New York. 395 p.

APPENDIX C
PERMITS AND REGULATIONS

103. GT FORM 2. APPLICATION FOR PERMIT TO DRILL, DEEPEN, OR REENTER AND OPERATE.

- a. Before any person shall commence operations for the drilling of a well, such person shall file with the Director an application on GT Form 2, for a permit to drill, along with a filing and service fee of Seventy-Five Dollars (\$75.00), and must secure the Director's approval before proceeding with such operation. "Observation Wells" as described in Section G123 herein, shall require an application for permit regardless of the depth of the wells, but one or more wells may be permitted under one permit by the Director commensurate with the scope of the application. All fees collected by the Commission for the issuance of permits described above and pursuant to Article 34-70-110 of the Act shall be credited to the "Geothermal Resource Fund" as set up by the Act.
- b. Before any person shall commence operations for the deepening of a well to any source of supply other than the existing producing horizon or for the reentry of a well, such person shall file an application on GT Form 2 and secure the approval of the Director.
- c. GT Form 2 shall be filed in duplicate for wells on all patented and Federal lands, and in triplicate for wells on all State lands. An accurate plat or map showing the location of the well and showing measurements necessary for the determination thereof shall be filed with the Director. Unless operations are commenced within six (6) months after the date of approval, the permit will become null and void; however, for good cause shown, the Director may grant an extension not to exceed an additional six (6) months.
- d. Prior to issuance of a geothermal exploration well permit, the Commission shall require the applicant to submit a written statement based on competent geological opinion or data derived from similarly situated geothermal resource areas containing whatever information the Commission requires to carry out the purposes as described in Section 34-70-102 of the Act. The requirement of such written statement must not place an undue burden upon the exploratory drilling process. Upon the applicant's request, such written statement shall be held confidential for one year after the completion of each well; however, the Commission shall make such written statements available, upon request, to the Division of Water Resources and the Colorado Geological Survey if the Division of Water Resources and the Colorado Geological Survey observe the same rules of confidentiality as the Commission.
- e. Prior to the issuance of a permit to drill a geothermal development well, the Commission shall require the applicant to submit a written statement, based on data derived from the discovery well drilling process, competent geological opinion, or data derived from similarly situated geothermal resource areas containing the following information:
 - 1) Names and addresses of the owner, operator, and designated agents of both;
 - 2) Location of the wells and proposed depth thereof;
 - 3) Description of the lease;
 - 4) Amount and extent of surface development anticipated;
 - 5) Measures taken to protect against land subsidence, contamination of surface and ground waters and the air, and excessive noise levels;

- 6) Proposed methods of geothermal by-product disposal and geothermal by-product recovery.
 - 7) Mineral and chemical composition of any brine and associated gases of the geothermal resource;
 - 8) Proposed casing program;
 - 9) Such other information as the Commission requires to carry out the purposes of the article as described in Section 34-70-102 of the Act.
- f. In order to protect against damage to the surface of the land or improvements thereon or to crops or to livestock, the applicant must submit to the Commission, along with either the exploration or the development permit application, evidence of public liability insurance commensurate with the scope of such application.
 - g. In the event that the owner requests revisions to the approved permit, which the Director considers to be significant, an amended Form GT2 must be filed with the Director for approval. The amended application will be assigned the same permit number as the original.
 - h. The Director may withhold the issuance of a permit, and the granting of approval of any application for Permit to Drill, Deepen, or Reenter, and Operate any well or proposed well that is located in an area for which an application has been filed for hearing to establish drilling units, or the Commission on its own motion, has called the hearing; provided that such hearing is to be held within a reasonable time, not to exceed sixty (60) days from the date on which the application was received for a permit; except however, the Director shall give special consideration to the issuance of a permit where an owner files a sworn statement and demonstrates therein to the Director's satisfaction that on the date said application for drilling units was filed;
 - 1) He had the right or obligation under the terms of an existing contract to drill said well; and
 - 2) He has a leasehold estate or a right to acquire a leasehold estate under said contract which will be terminated unless he is permitted to commence the drilling of said well before the matter of spacing can be fully heard and determined by the Commission.
 - i. The Director may also withhold permits for wells offsetting previously spaced areas and the Commission shall call a hearing within a reasonable time not to exceed sixty (60) days. Special consideration will be given to the issuance of a permit as is covered above.

DEPARTMENT OF NATURAL RESOURCES
OIL AND GAS CONSERVATION COMMISSION
OF THE STATE OF COLORADO

APPLICATION FOR PERMIT TO DRILL, DEEPEN OR REENTER AND OPERATE GEOTHERMAL RESOURCES WELL				5. LEASE DESIGNATION AND SERIAL NO.	
1a. TYPE OF WORK DRILL ☐ DEEPEN ☐ REENTER ☐				6. IF INDIAN, ALLOTTEE OR TRIBE NAME	
				7. UNIT AGREEMENT NAME	
b. TYPE OF WELL Expl. ☐ Dev. ☐ Obs. ☐ Other ☐ SINGLE ZONE ☐ MULTIPLE ZONE ☐				8. FARM OR LEASE NAME	
2. NAME OF OPERATOR				9. WELL NO.	
3. ADDRESS OF OPERATOR				10. FIELD AND POOL, OR WILDCAT	
4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.) At surface				11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA	
At proposed prod. zone					
14. DISTANCE IN MILES AND DIRECTION FROM NEAREST TOWN OR POST OFFICE				12. COUNTY	13. STATE
15. DISTANCE FROM PROPOSED LOCATION TO NEAREST PROPERTY OR LEASE LINE, FT. (Also to nearest drig. line, if any)		16. NO. OF ACRES IN LEASE*		17. NO. OF ACRES AND/OR DRILLING UNIT ASSIGNED TO THIS WELL	
18. DISTANCE FROM PROPOSED LOCATION TO NEAREST WELL, DRILLING, COMPLETED, OR APPLIED FOR, ON THIS LEASE, FT.		19. PROPOSED DEPTH		20. ROTARY OR CABLE TOOLS	
21. ELEVATIONS (Show whether DF, RT, GR, etc.)				22. APPROX. DATE WORK WILL START	
23. PROPOSED CASING AND CEMENTING PROGRAM					
SIZE OF HOLE	SIZE OF CASING	WEIGHT PER FOOT	SETTING DEPTH	QUANTITY OF CEMENT	

* DESCRIBE LEASE

Applicant must submit, in addition to this application, evidence of public liability insurance in order to protect against damage to the surface of the land or improvement thereon or to crops or livestock.

24. SIGNED _____ TITLE _____ DATE _____

(This space for Federal or State Office use)

PERMIT NO. _____ APPROVAL DATE _____

APPROVED BY _____ TITLE _____ DATE _____

CONDITIONS OF APPROVAL, IF ANY:

OIL AND GAS CONSERVATION COMMISSION
OF THE STATE OF COLORADO

BOND

GEO THERMAL RESOURCES

KNOW ALL MEN BY THESE PRESENTS, That we,

of the County of _____, in the State of _____
as principals, and _____
of _____, as surety, authorized to do business in the State
of Colorado, are held hereby and firmly bound unto the State of Colorado, in the penal sum
of (\$ _____), _____ Dollars, lawful money
of the United States, for the faithful payment of which we hereby bind ourselves, our heirs,
executors, administrators and assigns.

The condition of this obligation is that whereas the above bounden principals propose the drilling of a test well or wells for geothermal resources (on lands situated in the State of Colorado) on the following described land:

Blanket Bond: To Cover All Wells Drilled in the State of Colorado

Individual Bond: Well No. _____ Lease _____
Section _____ Township _____ Range _____
County, Colorado

NOW, THEREFORE, If the above bounden principals shall comply with all of the provisions of the laws of the State of Colorado and the rules, regulations and requirements of the Oil and Gas Conservation Commission of the State of Colorado, for the development and production of Geothermal Resources, with reference to properly plugging said well or wells, then this obligation is void; otherwise, the same shall be and remain in full force and effect.

Witness our hands, this _____ day of _____, 19____.

• Principals

Witness our hands, this _____ day of _____, 19____.

Approved: _____
Director, Oil & Gas Conservation
Commission of the State of Colorado

Dated: _____

Surety

OIL AND GAS CONSERVATION COMMISSION
OF THE STATE OF COLORADODESIGNATION OF AGENT
Geothermal Resources

The undersigned producer, operator, transporter, refiner, treatment or other extraction plant operator, or initial purchaser who is conducting geothermal operations in the State of Colorado, does, pursuant to the Rules and Regulations, and Rules of Practice and Procedure for the Development and Production of Geothermal Resources of the Oil and Gas Conservation Commission of the State of Colorado, hereby appoint, _____, whose address
(An Individual Representating the Organization)
_____, (his, her or its) designated agent to accept and to be served with notices from said Commission, or from other persons authorized under the Geothermal Resources Act of the State of Colorado.

The undersigned further agrees to immediately report in writing, all changes of address of the agent, and any termination of the agent's authority, and in the latter case, the designation of a new agent or agents shall be immediately made. This designation of agent, however, shall remain in full force and effect until and unless a new designation of agent is filed in accordance with said statute and said regulation.

Effective Date of Designation _____

Company _____

Address _____

Phone _____

By _____ (Title) _____
(Signature)

Blank

PROCEDURE FOR PERMIT APPLICATION

UNDER

"RULES FOR SUBSURFACE DISPOSAL SYSTEMS"

(Re: "Flow Chart - Rules for Subsurface Disposal Systems" - Attached)

INTRODUCTION

As a means of clarification, the following definition of Subsurface Disposal System is given to delineate what systems need a permit. A subsurface disposal system is any system or facility or method or excavation or well structure that disposes, whether by direct or indirect means, of wastes underground. The following systems, which dispose of wastes underground, are included and would require a permit:

- (a) Sewage Systems that do not have NPDES permits;
- (b) Treatment works - industrial and agricultural;
- (c) Wells into which wastes are deposited or injected;
- (d) Installations, structures, wells and excavations to be used in connection with any subsurface explosion, detonation, reaction or process that might tend to discharge, deposit or generate wastes underground;
- (e) Mines or other excavations initially made for other purposes when they are used for disposal [see items (j), page 2].

The systems that are NOT required to have a Subsurface Disposal Permit are:

- (a) Individual sewage disposal systems.
- (b) Systems utilizing unlined lagoons that are not more than 10 feet below adjacent ground level, nor built-up more than 10 feet above adjacent ground level. However, they must receive a determination from the Water Quality Control Division as being a non-polluting system.
- (c) Those systems, other than the unlined lagoons in (b), that dispose of pollutants not more than 10 feet below the adjacent ground level

and that have received a determination from the Water Quality Control Division as being a non-polluting system.

- (d) Solid waste disposal sites.
- (e) Sanitary landfills.
- (f) Refuse disposal sites.
- (g) Oil and gas wells.
- (h) Water injection wells employed in oil and gas well operations - permitted by Oil and Gas Commission.
- (i) Surface ditches or retention ponds (used in water transportation systems) and irrigation and water transportation systems. In such systems the primary and/or sole purpose of the system must be to only transport water.
- (j) Disposal of broken rock and coal, metal mine tailings and mill tailings (this does not include material from uranium mines and mills and, therefore, a permit is required for uranium mine & mill tailings.) in underground mine openings when such disposal has received an NPDES Permit and determination from the Water Quality Control Division as being a non-polluting system. It is important to note that a written determination of exemption must be specifically obtained.

From the above discussion it is apparent that there are sites that require permits, sites that require determinations by the Water Quality Control Division or sites that neither a permit nor a determination is required. If a permit or a determination is required then the following procedure is presented to assist the applicant. Please remember that this is a general procedure for application; and, therefore, not all items listed will apply to every application.

The Attached Flow Chart indicates the sequential steps required for processing each application. The Flow Chart notes the maximum time required for Permit Processing.

Procedure for Permit Application

I. Determination (Case I) [See flow chart]

The procedure for a determination from the Water Quality Control Division will consist of the following:

- A. A brief explanation of the site and of the disposal practice will be prepared utilizing the items listed on pages 6-7 in the "Rules for Subsurface Disposal Systems".
- B. A meeting with personnel in the Water Quality Control Division will be scheduled for submittal of the explanation. After the submission there will be a 30-60 day review of the explanation. Complexity of the site/disposal system(s) will determine the length of time for review.
- C. After the 30-60 day review, a second meeting will be scheduled at which time the Division's determination will be given.
- D. If it is determined that a permit is necessary, the procedure listed for Permits will be followed.
- E. If no permit application must be submitted, then a letter of exemption by the Division will follow.

II. Permit (Case II) [See flow chart]

- A. References - The Applicant is referred to the following for information:

- (a) Regulation 2.1.1-Procedural Regulations for all Proceedings before the Water Quality Control Division April 1, 1978;

(b) Title 25 Article 8 - Colorado Water Quality Control Act
July, 1975;

(c) Regulation 7.2.0 - Rules for Subsurface Disposal Systems
October 1, 1977.

- B. The applicant, who has not applied under the Determination procedures above (Case I) will complete the next two items. These two items are similar to I, A & B. Those applicants that have completed these items for a Determination will need more detail for a permit application . (Step 5 on the Flow Chart).
- C. A detailed explanation of the site and of the disposal practice will be prepared utilizing the items listed on pages 6-9 in the "Rules for Subsurface Disposal Systems". Once the applicant feels a sufficient amount of information has been obtained for a preview, a preliminary review with the Water Quality Control Division will be scheduled. At this time, an evaluation will be made as to whether there is a need for additional data. Should there be a requirement for a additional data, this would make a second preliminary review necessary in order to verify the completeness of the application package. (Step 6A).
- D. Once the applicant has completed the application package for a subsurface disposal permit, a meeting is to be scheduled with Water Quality Control Division. Three complete application packages will be submitted to the Division. The purpose of this meeting will be to provide both the applicant and the Division an opportunity to clarify the information provided in the permit package, prior to formal submittal. (Step 7).

E. The permit package will be reviewed for completeness. At the time that the package is found to be sufficiently complete for evaluation, the applicant will be notified by the Division that the application has been accepted for formal submittal & evaluation. There will then be a 30-60 day review period. The length of time spent will depend upon the complexity of the system and whether a private consultant to the Division will be asked to review those portions of the permit where the Division lacks expertise or desires a third party opinion (see 7.2.4 (11) of "Rules for Subsurface Disposal Systems"). The consultant will be funded by the applicant.

At the time of notification of permit completeness, the applicant should initiate notification of property owners (Step 9) within a 2 mile radius of the proposed site. A vested water right will be considered property. Affidavits of the mailing or proof of acceptable publication should be presented to the Technical Secretary's office (Rm. 319, Ext. 3378) at the Colorado Department of Health. The Division will arrange for an adjudicatory hearing before the Water Quality Control Commission (Steps 9B-9E) through the Technical Secretary's office. The hearing date should not be scheduled sooner than the 60 day maximum review period. Additional tasks to be completed at the Technical Secretary's office include:

- (a) Presenting 20 copies of an Executive Summary, four copies of the twenty will be the complete permit package;
- (b) Request the Technical Secretary to make notification in the Colorado Register a minimum of 20 days before the scheduled hearing date.

- F. The applicant or the Water Quality Control Division may apply to the Technical Secretary's Office for a pre-hearing conference, which will be held not less than 15 days in advance of the adjudicatory hearing. See Procedural Rules for the Water Quality Control Commission paragraph 2.1.9, page 11.
- G. After the Adjudicatory Hearing and the Permit has been written by the Water Quality Control Division, the applicant will provide the required bond (determined by the Division) and a one thousand dollar permit fee to the Division.
- H. Appeal Process. Any party directly affected by the Commission action has the right to request reconsideration within 30 days following the agency's final action on the application. The request must be acted upon by the Commission within 10 days after its receipt. The filing of a request for reconsideration is not a prerequisite to appeal of the agency decision, but it does have the effect of "tolling" or suspending the running of the 30 day period for seeking judicial review.

FLOW CHART - RULES FOR SUBSURFACE DISPOSAL SYSTEMS

Case I

Definition of Subsurface Disposal System Required "Determination" By Division

Prepare Brief Explanation of Disposal System See pp 6-7 "Rules for Subsurface Disposal"

(1)

Meeting with the Division to Submit Explanation of Disposal System

(2)

30-60 Days

Division Gives Determination of Exemption or a Permit is Necessary

(3)

System Needs a Permit

(A)

Case II

Definition of Subsurface Disposal System Requires a Permit

Prepare Detailed Explanation for Application Package. See pp. 6-9 Rules for Subsurface Disposal

(5)

Preliminary Review of Application For a Disposal System.

(6A)

Meeting with Division for Explanation of Complete Application Package. 3 copies Necessary for Division

(7)

(B)

Request for Additional Data. Info, Maps or Descriptions to Support Application.

(6B)

Notify Property Owners within 2 Mile Radius of Site.

(9A)

(C)

DRAFT COPY

DRAFT COPY

Blank

APPENDIX D

SERVICE AND MATERIAL SUPPLIERS

Consultants:

Bill Moore, Sales Engineer
Engineered Products Co.
1204 W. Cedar Avenue
Denver, CO 80223
(303) 777-4471
Contact for: Boilers, pumps, heating equipment,
heat exchangers, piping

Lon Parmely, Sales Engineer
Long and Associates, Inc.
2080 W. Cornell Avenue
Englewood, CO 80110
(303) 1-7493
Contact for: Heat pumps, heat exchanger, heating equipment

Pipe

Fiberglas Reinforced Pipe with Insulation
Rovanco Corp.
I-55 and Frontage Road
Joliet, Ill. 60436
Local Contact: Bill Moore (815) 726-0640

Asbestos-Cement, Insulated & Uninsulated
Johns-Manville
9722 Majestic Drive
Longmont, CO 80501
(303) 652-2073
or
P.O. Box 5771
Denver, CO 80217
Local Contact: James S. Andrews (303) 773-2400

Steel Pipe with Insulation
Thermacor Process, Inc.
500 N.E. 23rd
Fort Worth, TX 76106
Contact: Rick Bender (817) 624-1181

Heating Equipment

Hot water units
Modine Manufacturing Co.
1500 De Koven Avenue
Racine, WI 53401
(414) 636-1200
Local Contact: Lon Parmely

Finned-Tube Radiators
Sterling Radiator Co.
260 North Elm Street
Westfield, Massachusetts 01085
Local Contact: Lon Parmely

Multi-Zone Air Conditioning Units
Bohn Heat Transfer Division
Gulf & Western Manufacturing Co.
Danville, Illinois 61832
(217) 446-3710
Local Contact: Lon Parmely

Fan Convectors
Myson International Limited
Colchester, CO2 9LE
England
Local Contact: Bill Moore

Heat Pumps

Westinghouse Electric Corp.
Industrial-Commercial Templifier Dept.
P. O. Box 2510
Staunton, VA 24401
Local Contact: Lon Parmely

Plate Heat Exchangers

Patterson-Kelly Co.
East Stroudsburg, Pennsylvania 18301
Local Contact: Bill Moore

Alfa-Laval Inc.
HVAC Equipment Division
Fort Lee, NJ 07024
(201) 592-7800
Local Contact: Lon Parmely

Tranter Inc.
P.O. Box 2289
Wichita Falls, TX 76307
(817) 723-7125
Local Contact: Ted Miller Associates, Inc.
2140 S. Ivanhoe, Denver, CO 80222
(303) 758-3912

Boilers

Cleaver Brooks
P.O. Box 421
Milwaukee, WI 53201
Local Contact: Tom Mansfield,
Thomas Mansfield Co.
3345 S. Platte River Drive
Denver, CO (303) 789-1504

Kewanee Boiler Corp.
Suite 200
16100 Chesterfield Village Parkway
Chesterfield, Missouri 63017
(314) 532-7755
Local Contact: Bill Moore

Bethlehem Corp.
225 W. Second St.
Bethlehem, Pennsylvania 18016
(215) 867-4605
Local Contact: Allan Harte
Engineered Sales and Services, Inc.
3820 Forrest St.
Denver, CO 80207
(303) 399-7964

Pumps

McLemore Pump & Equipment Co. 4895 Joliet St., Unit L
Denver, CO 80239
Local Contact: J.R. McLemore
(303) 371-5730

Thelco Corp.
2390 W. Dartmouth
Englewood, CO 80110
Local Contact: Stacey Pickup
(303) 761-7616

Control Systems

Johnson Controls, Inc.
1440 S. Lipan
Denver, CO
Local Contact: Leon White
(303) 744-1321

Honeywell, Inc.
5275 DTC Parkway Denver, CO
(303) 779-6200

Blank

262

APPENDIX E

BIBLIOGRAPHY AND REFERENCES

- American Association of Petroleum Geologists, 1974, Geothermal gradient map of North America: Amer. Assoc. Petroleum Geol. Geothermal Gradient Portfolio Map 15, Tulsa, Oklahoma.
- ASHRAE, 1972, Handbook of Fundamentals, American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc.
- Baas-Becking, L.G.M., Kaplan, I.R., Moore, Derek (1960): Limits of the Natural Environment in Terms of pH and Oxidation-reduction Potentials. Jour. Geol., V. 68, p. 243-284.
- Barrett, J.K. and Pearl, R.H., 1976, Hydrogeological data of thermal springs and wells in Colorado: Colorado Geol. Survey Info. Series No. 6, p. 32-40.
- Barrett, J.K. and Pearl, R.H., 1978, An appraisal of Colorado's geothermal resources: Colorado Geol. Survey Bull. 39, 224 p.
- Bass, N.W. and Northrop, S.A., 1963, Geology of the Glenwood Springs quadrangle and vicinity, northwestern Colorado: U.S. Geol. Survey Bull. 1142-J, 74 p.
- Behrendt, J.C. and Bajwa, L.Y., 1974, Bouguer gravity map of Colorado: U.S. Geol. Survey Geophysical Inv. Map GP-895.
- Booth, J. R. Jr., Shepherd, B. P., Mulhenny, W. F., (1972): Final Disposition of Effluent Brines from Inland Desalting Plants. INT-OSW-ROPR-72-817, Office of Saline Water, Washington. 181 p.
- Bromberg, Kenneth, 1980, personal communication.
- Calhoun, J., 1953, Fundamentals of reservoir engineering: Univ. Oklahoma Press.
- Cole, Jean, 1980, District 5 Water Referee, personal communication.
- Colorado School of Mines, 1977, Geophysical surveys at Pagosa Springs and Glenwood Springs, Colorado: unpub. report by Colorado School of Mines under contract to the Colorado Geol. Survey, Denver, Colorado, 57 p.
- DeBrine, Bruce, 1980, Colorado State Department of Natural Resources, State Engineer, personal communication.

- Dick, J. D., 1978 Potential energy from hydrothermal resources in Colorado: Chaffee Geothermal, Ltd. unpub. industrial report, Denver, Colorado, 9 p.
- Eckert, E. R. G. and Drake, Robert M., Jr., 1959, Heat and Mass Transfer, 2nd Edition, McGraw-Hill, New York.
- Ellis, A. J. and Mahon, W. A. J., (1977): Chemistry and Geothermal Systems, Academic Press, New York.
- _____, 1977, Final Adoption: "Rules for Subsurface Disposal Systems", Colorado Department of Health.
- Fitzpatrick, J. J., 1980 written communique.
- Fournier, R. O., and Rowe, J. J., 1966, Estimation of underground temperatures from the silica content of water from hot springs and wet-steam wells: Am. Jour. Sci., vol. 264, p. 685-697.
- Fournier, R. O., and Truesdell, A. H., 1973, An empirical Na-K-Ca geothermometer for natural waters: Geochim. et Cosmochim. Acta. Vol. 37, p. 1255-1275.
- _____, 1974, Geochemical indicators of subsurface temperature -part 2, Estimation of temperature and fraction of hot water mixed with cold water: U.S. Geol. Survey Jour. Research, Vol. 2, no. 3, p. 263-270.
- Fournier, R. O., White, D. E., and Truesdell, A. H., 1974, Geochemical indicators of subsurface temperature - part 1, Basic assumptions: U.S. Geol. Survey Jour. Research, Vol. 2, no. 3, p. 259-262.
- Fox and Associates, 1975, Roaring Fork and Crystal valleys - an environmental and engineering study: Colo. Geol. Survey Environmental Geology number 8.
- Garrels, R. M. and Thompson, M. E., (1962); A Chemical Model for Sea Water at 25°C and one Atmosphere Total Pressure, Am. Jour. Sci., V. 260, p. 57-66.
- Geothermal Resource Council, Special Report No. 7, 1979, Direct Utilization of Geothermal Energy: A Technical Handbook, California.
- Geothermal Resources Council Annual Meeting, 1979, Expanding the Geothermal Frontier, Vol. 3, California.
- Geothermal Resource Council, 1978, Direct Utilization of Geothermal Energy: A Symposium, Washington, D.C.
- Geothermal Resources Council Annual Meeting, 1978, Geothermal Energy: A Novelty Becomes a Resource, Vol. 2, Section 1 and 2, California.

- Geyer, R., 1980, written communique.
- Hansen, R. L., 1975, Analysis of thermal infrared remote sensing data - Colorado River, Glenwood Springs to Dotsero: Bur. Reclamation Memorandum, Engineering Physics Section, Denver, Colorado, 23 p.
- Helgeson, H. C., (1969): Thermodynamics of Hydrothermal Systems at Elevated Temperatures and Pressures. Am. Jour. Sci., V. 267, p. 729-804.
- Hydrosciences, Inc., 1979, Geohydrological analysis of the geothermal reservoir at Pagosa Springs, Colorado: contract report prepared for Coury & Associates, Inc., Lakewood, Colorado.
- Kauffman, D., and Houghton, A. V., 1980, Engineering and economic evaluation of direct hot water geothermal energy applications on the Univ. of New Mexico campus: technical progress report to the Idaho Operations Office, Dept. of Energy contract DE-AS07-79ID 12048, p. 75 & 76.
- Kiel, Jerry, 1980, personal communication.
- Klusman, R. W., Cowling, S., Culvey, B., Roberts, C., and Schwab, A. P., 1977, Preliminary evaluation of secondary controls on mercury in soils of geothermal districts: Geothermics Vol. 6, p. 1-8.
- Koulet, K. G., and Armstrong, J. A., 1978, An environmental report on the drilling and production testing of an exploratory geothermal well in Glenwood Springs, Colorado: Denver Res. Inst., Laboratories Applied Mechanics, Denver, Colorado.
- Landon, R. E., 1933, Date of recent volcanism in Colorado: Am. Jour. Sci., 5th ser., Vol. 25, p. 20-24.
- Millison, C., 1980, written communique.
- Minor, Michael, 1980 personal communication.
- Nannen, L. W., F. Kreith and R. E. West, 1975, "An Investigation of the Technical and Economic Feasibility of Using Low Temperature Geothermal Sources in Colorado, a final report to Colorado Energy Research Institute.
- Papazian, P. B., 1979, Topographic modeling of resistivity surveys using the Schwarz-Christoffel transformation: Colorado School of Mines Master's Thesis T-2205.
- Pearl, R. H., 1972, Geothermal Resources of Colorado: Colorado Geol. Survey Spec. Pub. 2, p. 14.
- Pearl, R. H., 1979, Colorado's hydrothermal resource base - an assessment: Colorado Geol. Survey Res. Series 6, p. 28-30.

- Phillips, S. L., Mathur, A. K., Doebler, R. E. (1977): A Study of Brine Treatment. EPRI ER-476, Project 791, LBL-6371, UC-66d, TID-4500-R65.
- _____, 1974, Proceedings of the International Conference on Geothermal Energy for Industrial, Agriculture and Commercial - Residential Uses: Multipurpose Use of Geothermal Energy, Geo-Heat Utilization Center, Oregon Institute of Technology, Oregon.
- Ray, Stuart W., "Financial Costing Guidance for the Policy and Fiscal Guidance", memorandum dated March 28, 1979, Office of Planning and Regulatory Program Evaluation, Policy and Evaluation, U.S. Department of Energy, Washington, D.C.
- _____, 1978, "Regulations for Implementing the Procedural Provisions of the National Environmental Policy Act", Council on Environmental Quality, Executive Office of the President, Washington, D.C.
- Renner, J. L., White, D. E., and Williams, D. L., 1975, Hydrothermal convection systems in Assessment of geothermal resources of the United States - 1975: U.S. Geol. Survey Circ. 726, p. 32-33.
- Rinehart, J. S., 1980, written communiqué.
- Robinson, C. J., Langford, R. H., Brookhart, J. W., (1958): Saline-Water Resources of North Dakota, U.S.G.S. Water-Supply Paper 1428, 72 p.
- Sammel, E. A., 1978, Occurrence of low temperature geothermal waters in the United States in Assessment of geothermal resources of the United States - 1978: U.S. Geol. Survey Circ. 790, p. 106-107.
- UHL, Vincent W., A Standard Procedure for Cost Analysis of Pollution Control Operations; Volume II. Appendices, (EPA-600/8-79-018b), U.S. Environmental Protection Agency, Washington, D.C., June 1979.
- U.S. Bureau of Reclamation, 1976, Colorado River water quality improvement program-Glenwood/Dotsero springs unit - Appraisal report: U.S. Bur. Reclamation, Upper Colorado Region, Denver, Colorado.
- U.S. Department of Energy, Environmental Control Costs for Oil Shale Processes, (DOE/EV-0055), Washington, D.C., October 1979.
- Vranesh, George and John D. Musick, Jr., 1977, Geothermal Resources: Water and Other Conflicts Encountered by the Developer-An Alternative Energy Source Which is "Gathering Steam", Vol. XIII, No. 1, College of Law, University of Wyoming.
- Zeitz, I., and Kirby, J. R., Jr., 1972, Aeromagnetic map of Colorado: U.S. Geol. Survey Geophysical Inv. Map GP-836.