AGRIBUSINESS GEOTHERMAL ENERGY UTILIZATION POTENTIAL OF KLAMATH AND WESTERN SNAKE RIVER BASINS, OREGON

FINAL REPORT

PAUL J. LIENAU
Principal Investigator

March 1978

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Oregon Institute of Technology
Klamath Falls, Oregon 97601

Oregon Department of Geology & Mineral Industries
Oregon Department of Economic Development
Portland, Oregon

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ABSTRACT

Resource assessment and methods of direct utilization for existing and prospective food processing plants have been determined in two geothermal resource areas in Oregon. Ore-Ida Foods, Inc. and Amalgamated Sugar Company in the Snake River Basin; Western Polymer Corporation (potato starch extraction) and three prospective industries--vegetable dehydration, alfalfa drying and greenhouses--in the Klamath Basin have been analyzed for direct utilization of geothermal fluids. Existing geologic knowledge has been integrated to indicate locations, depth, quality, and estimated productivity of the geothermal reservoirs. Energy-economic needs and balances, along with cost and energy savings associated with field development, delivery systems, in-plant applications and fluid disposal have been calculated for interested industrial representatives.

CONVERSION TABLE

The policy of U.S. DOE is to encourage use of the metric system, formally called the International System of Units (SI). This report uses metric units for resource assessment and engineering units for the engineering and economic section. The following table shows conversion factors used.

Quantity	To convert from	To	Multiply by
Length	cm	inches	3.937×10^{-1}
	m	feet	3.281
	km	mile	6.215×10^{-1}
Area	m^2	ft^2	1.076×10^1
	m^2	acre	2.471×10^{-4}
Volume	m^3	ft^3	3.531×10^1
Temperature	°C	°F	$tf = 1.8\ tc + 32$
Temperature difference	ΔTk	ΔTf	1.8
Mass	kg	pound	2.205
Pressure	kN/m^2	psi	1.450×10^{-1}
	kN/m^2	inches of Hg	2.953×10^{-1}
Energy	k cal	Btu	3.968
	J	Btu	9.479×10^{-4}
	J	kWh	2.778×10^{-7}
	J	ft-lb	7.375×10^{-1}
Power	W	Btu/h	3.412
Flow	kg/sec	lb/h	7.920×10^3
	m^3/s	gpm	1.585×10^4
	m^3/s	cfm	2.119×10^3
Enthalpy	k cal/kg	Btu/lb	1.143×10^{-1}
	J/kg	Btu/lb	4.299×10^{-4}

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I. INTRODUCTION

A. General

The study of geothermal energy utilization potential for agribusiness
industries in the Klamath and Western Snake River Basins, Oregon, was
conducted by Oregon Institute of Technology's Geo-Heat Utilization Center,
the Oregon Department of Geology and Mineral Industries, and the Oregon
Department of Economic Development, under ERDA contract EY-76-S-07-1621.
This is the final report for the program which spanned the period from
1 October 1976 to 31 March 1978.

The project activity included contributions from the following personnel:

√Oregon Institute of Technology   950 085¹

Paul J. Lienau	Principal Investigator
Charles V. Higbee	Economic Analysis
Saul Laskin	Engineering
John W. Lund	Engineering

√ Oregon Department of Geology and Mineral Industries

Donald A. Hull	Resource Assessment
Richard Bowen	Resource Assessment, Western Snake River Basin
Norman Peterson	Resource Assessment, Klamath Basin

√ Oregon Department of Economic Development

James E. Curtis	Industry Contacts, Klamath Basin
John N. Groupe	Industry Contacts, Western Snake River Basin

As indicated in Appendix D, many organizations cooperated with the inves-
tigators by providing supporting information during the course of this
project.

The work described in this report was conducted for the Division of Geo-
thermal Energy, Department of Energy (DOE). John L. Griffith, Idaho
National Engineering Laboratory, Idaho Falls, Idaho, is the Project
Manager.

B. Objective

The objective is to investigate the potential use of geothermal energy
for direct heat applications in existing and prospective food processing
plants located in two geothermal resource areas of Oregon.

To develop an awareness in the agribusiness community of the existence
and extent of the geothermal resource, the means of exploiting the re-
source and the economics associated with the utilization.

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II. SUMMARY AND CONCLUSIONS

The primary results and conclusions of the work discussed in the following sections of this report are summarized in this section.

The two areas chosen for study have known geothermal resources in potentially significant amounts and additionally are in regions with well-developed, agricultural-based economies. The Klamath and Western Snake River Basins share many geologic characteristics, the principle identifying characteristic is the tensional faulting that has broken the region into a series of linear valleys and mountain ranges. Other significant characteristics shared by the two areas are widespread late Cenozoic volcanism, lake basin sedimentation, and the presence of thermal springs.

In the Klamath Basin there is a wealth of information on the location of near-surface geothemal waters and of practical methods of utilizing this resource, but little information on deeper rocks and how they may be affecting the presence of the shallower geothermal waters.

From this and other studies of the Klamath Basin, it appears the regional geothermal gradient is near 75°C per km. If the regional gradient is in the range of 75°C per km, water with sufficient temperature for space heating (45° to 50°C) can be expected to occur regionally at depths of 1,500 to 2,000 feet. Zones of upwelling higher-temperature waters (90° to 100°C) have been found and should be expected adjacent to faults. And, it is probable that deeper drilling to depths of 2,500 to 3,200 feet will intersect waters at least as high as 130°C, the estimated reservoir base temperature in the region.

The Klamath Basin geothermal systems have a very great potential for space heating and industrial applications. Calculated estimates by White and Williams (1975) of the thermal energy that can be applied directly to its intended direct use (assuming 25 percent of the stored energy recovered at the surface and efficiency of utilization also 25 percent) is 1.5×10^{18} calories and if this useable heat were to be supplied by electrical energy, it would require 1,990 MW-century. The heat content in the shallow-water system is estimated to be in the range of 12×10^{18} to 36×10^{18} calories and could be one of the largest in the United States.

In the Western Snake River Basin deep drilling for suspected occurrences of oil and natural gas have provided a general knowledge of the existence and depths of deep potential geothermal reservoirs, but because the near-surface indications of hot water are sparse, there has been little development of the type that is being practiced in the Klamath Basin.

Surface hot springs, thermal gradients, water well temperature and regional geologic, hydrologic, and geophysical studies were all used to determine potential geothermal resource targets shown on individual

resource assessment maps. In the Snake River Basin a higher-than-normal heat flow is present and favorable temperatures can be predicted at reasonable depths. The measured and projected geothermal gradients have been the main indicators of targets at shallower depths.

This study, along with others indicates the region has an average geothermal gradient of about 85°C per km. The overlying Chalk Butte Formation has a consistent lithology of mostly tuffaceous siltstone and claystone with minor poorly sorted sand and gravel. Because of the consistent lithology a geothermal gradient measured in the upper 50 to 150 m can be expected to remain relatively constant until a differing lithology or a zone of moving groundwater is reached. By projecting the 85°C per km geothermal gradient to 1.0 km, the temperature at that depth can be assumed to be about 95°C (85° + 10° surface temperature). Deeper wells in the same area drilled to the Owyhee Basalt would expect to penetrate 0.1 to 0.4 km of Grassy Mountain Basalt with a small increase in temperature to underlying Kern Basin Formation where a gradient of around 70°C/km would be expected. Therefore, by drilling to the Owyhee Basalt about a kilometer below the Grassy Mountain Basalt, temperatures of about 165°C (95 + 70°C) can be expected.

Energy-economic needs and balances, along with cost and energy savings associated with field development, delivery systems, in-plant applications and fluid disposal have been determined for Western Polymer Corporation in the Klamath Basin and Amalgamated Sugar Company and and Ore-Ida Foods, Inc. in the Western Snake River Basin. In addition three prospective industries, which would be applicable in either basin, onion dehydration, alfalfa drying and greenhouses were studied.

Western Polymer Corporation

Western Polymer Corporation is located on the Oregon-California border 21 miles south of Klamath Falls and processes 14 tons of potatoes per hour for starch extraction. The plant consumes 122,250 gallons of propane annually, of which 85 percent is used for drying starch by means of cyclone separators.

Three options were considered in converting the plant to geothermal energy. The third and most attractive option considered drilling an existing 1,200-foot well to a depth of 3,000 feet in hopes of encountering 180° to 200°F geothermal water. The water would be pumped through 300 feet of asbestos cement pipe to the preheat finned-tube water-to-air heat exchanger and supply 2.4×10^6 Btu/hr of the 3.5×10^6 Btu/hr required for starch drying. Reject water from the finned-tube heat exchanger would be used for space heating of the plant. This system would supply 76 percent of the thermal energy requirements for space and process heat.

The total first-year cost for option three is $61,250 intangible costs and $63,570 tangible costs, for a total capital outlay of $124,800. The intangible costs would be expensed in the first year, providing a tax reduction of $29,400 for a net intangible cost of $31,850. An investment tax credit of $12,714 in the first year would be available on

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the tangible costs and with 200 percent declining balance depreciation
assuming a ten-year life and 10 percent or less salvage value this op-
tion would provide a 27 percent return on investment and a payback period
of slightly less than five years.

Onion Dehydration

Onion dehydration involves the use of a continuous operation, belt con-
veyor in four stages using fairly low-temperature hot air from 100° to
220°F. Typical processing plants will handle 10,000 pounds of raw pro-
duct per hour (single-line), reducing the moisture from around 83 per-
cent to 4 percent (1,500 pounds finished product). These plants pro-
duce 10 million pounds of dry product per year using from 0.15 to 0.20
therms per dry pound produced (+0.06 therms of electrical energy), or
4,000 Btu per pound of water evaporated. The energy requirements for
the operation of a dryer will vary due to differences in outside tem-
perature, dryer loading, and requirement for the final moisture content
of the product.

One type of processing equipment, the Proctor dehydrator, requires
86,500 ft^3 of air per minute and up to 40 million Btu per hour. Due
to the moisture removal the air can in some cases only be used once,
and thus is exhausted. Special silica gel--Bryair, dessications units
are required in the final stage. The reject water from the Bryair pre-
heater has a temperature of 192°F; thus this could be used for space
heating, greenhouses or other low-temperature energy needs. Approxi-
mately $200,000 in fuel are thus used for a single-line dryer in a year's
operation (180 days).

A design was made to convert the Proctor dehydrator to geothermal energy
using a 20°F minimum approach temperature between the geothermal water
and process air. A well with 230°F water is required for this. This
temperature is available in the Klamath Basin; however, a deeper well
(2,000 to 3,000 feet deep) will probably be required.

Since there currently are no onion dehydration plants in either basin,
the cost analysis was done by investigating the cost difference in es-
tablishing a plant using conventional fuel (natural gas) versus geo-
thermal energy. Assuming a 20-year operating life the total annual
equivalent costs for the geothermal system (58 percent--production,
12 percent--delivery, and 30 percent--conversion) is $42,255 plus
$7.74 per hour for electricity and natural gas for the Bryair. The
total annual equivalent costs for the conventional system is $5,575
plus $210 per hour for energy costs. A break-even analysis indicates
that the plant would have to operate only 180 hours per year in order
to make the geothermal system competitive with natural gas.

Alfalfa Drying

There are several reasons for fuel drying the final alfalfa product in-
stead of complete sun wilting. Fuel drying produces a harder and heavier
pellet, and retains a greater percent of vitamin A and xanthrophyll.

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Ideally, 100,000 to 125,000 international units of vitamin A and xanthrophyll are needed; however, this can only be achieved by complete fuel drying. By field wilting and then some fuel drying, they can retain a minimum of 17 percent protein and an average of 55,000 international units of vitamin A (xanthrophyll is assumed to be at about the same level as vitamin A). In addition, a bright green color is maintained that appears to improve the sellability of the product. Complete dehydration at this time does not appear to be economical and no new plants are being built along this line.

A plant that uses a combination of field wilt and fuel drying will produce 80 to 110 tons of pellets per eight-hour shift. The alfalfa is purchased (or costs the company) at $45 to $55 per ton standing (at 12 percent moisture), and costs an additional $20 per ton to harvest and pellet. Of the total cost $2.50 is due to the actual drying or about six gallons of fuel oil per ton of alfalfa. This fuel usage can range from 5 to 30 gallons per ton depending upon the moisture content and the ambient conditions. The total cost of pellets is $65 to $75 per ton, of which about $5 per ton is the margin of profit. Thus, any fuel savings by converting to geothermal would have a significant percentage effect on the margin of profit. A geothermal energy conversion design was made for the combination field wilt and fuel drying. Using a 200°F air drying temperature for the dryer would require at least 220°F geothermal water. One well could provide the required flow, with one injection well for the reject water. Due to the high energy requirements and flow rates, a four-pass fixed water-to-air heat exchanger would be required.

Annual equivalent fixed costs for the geothermal system are $16,583 (67 percent--production, 9 percent--delivery, and 24 percent--conversion) and require 362 operating hours annually in order to break even with a fuel oil-fired system. By using geothermal energy the harvesting and process costs would be cut from $20 to less than $16 per ton providing a 13.6 percent profit margin per ton of product. A plant producing 10,000 tons annually would require five years of operation to pay back the capital investment costs of a geothermal system at 9 percent per annum.

A facility that has an annual output of between 25,000 and 30,000 tons of pellets would realize a savings of $100,000 per year over a conventional plant.

Greenhouses

Nearly every type of terrestrial commercial crop has been grown in greenhouses. The potential for the greenhouses to be used for specific crops was studied for the Klamath Basin. Tree seedlings for reforestation appear to be the most attractive crop at this time. Lower-temperature geothermally heated water can be utilized for greenhouses than for most agribusiness industries. Geothermal resources of temperature above 60°C have been used successfully for this application. However, heating greenhouses geothermally does require large quantities of water, especially if lower temperature of water are utilized.

The greenhouse business benefits from the size or scale of operation. For purposes of this study a one-acre unit house is used as the basis for a 15-acre operation. An effort was made to determine the optimum design of a heating system for a 15-acre complex of greenhouses.

Cost differences between the conventional and geothermal heating systems were used in calculating the return on investment (ROI). Additional capital investment of $331,393 is required for the geothermal system. The ROI calculation based on fuel savings yielded 162 percent.

Amalgamated Sugar Company

The Nyssa, Oregon sugar refinery is the seventh largest beet sugar processing plant in the United States. This plant can process 6,300 tons of sugar and 200 tons of molasses per day by means of the Steffen Process. When the plant is operating, 617 tons of coal are burned in the boilers per day. The plant converted from burning natural gas as its main fuel supply to coal in the early 1970s. Electric generators produce 5000 kw; in addition, 3000 kw are purchased. Exhaust steam from the generators at 50 psia is used primarily for process in the first effect of the quintuple-effect evaporators. Approximately 110 pounds of steam per second are generated by the coal-fired boilers being consumed by the following: 75 percent to evaporators, 4 percent to turbines, 6 percent live steam to process, 10 percent to evaporation to form concentrated Steffen Filtrate (CSF) and pulp dryers, and 5 percent to steam venting and losses. The company is trying to reduce energy consumption by 20 percent.

The high use of energy in the evaporation process makes it an attractive candidate for conversion to geothermal energy. Two ways of doing this are apparent. One method would use the full flow of geothermal fluid through the first-effect evaporator. The second alternative would employ only steam flashed from the geothermal fluid in the first effect, the water fraction of the flow being discarded.

The flashed steam method was determined to be the most satisfactory method and assumed the geothermal fluid would be available at 327°F and 8.3 percent quality, fixing the enthalpy at 369 Btu/lb. If the fluid is throttled down to a pressure of about 49 psia, 0.125 pounds of steam will be available for each pound of geothermal fluid throttled. Further, this steam will be exactly at the conditions of the steam currently used. So, to obtain 77 lb/sec of steam, the quantity currently used, the quantity of geothermal fluid required would be about 620 lb/sec. It is estimated that seven self-flowing wells would provide this flow rate. A 22-inch steam delivery line and 6-inch condensate return line runs from the well field to the plant, a distance of 1,200 feet.

In 1964, Amalgamated obtained a 25-year coal contract at a price of $10 per ton. With 12 years remaining on this contract the inflation rate for the next 12 years will consist of labor and transportation, which is currently $10.75 per ton inflating at a rate of 7.5 percent

annually. Pollution control equipment could be salvaged with a 68 percent loss resulting in a tax reduction of $648,000 and a savings in maintenance costs. However, electric power cost would increase by $166,350 per annum due to the shutdown of steam turbines.

Total annual savings before depletion and taxes equals cost of coal + pollution control maintenance - (increased power costs + geothermal system maintenance) with all costs projected ten years at their respective inflation rates. The depletion allowance is subtracted from the total annual savings to lower federal taxes due to energy costs. A ten-year projection of cash inflow after taxes indicates a payback in the sixth year at a 20 percent ROI. A 26 percent ROI would be realized with a ten-year project life.

Ore-Ida Foods, Inc.

Ore-Ida Foods, Inc., a division of the H. J. Heinz Company, is located on the Oregon-Idaho border near the Snake River at Ontario, Oregon. Their major product is frozen potato products, processing over two million pounds of potatoes per day resulting in over one million pounds of frozen potato products.

Two natural gas-fired boilers supply an average of 120,000 lb/hr of steam to process with 40 percent returned as a condensate. All processes except frying utilize direct injection of steam at 100 psig, which employs heat exchangers and steam at 275 psig. The fryers consume 45 percent of the energy of the plant and since the return temperature is greater than 300°F, the assumed geothermal water supply temperature, 55 percent of the process energy requirements can be supplied by geothermal energy. It is estimated that the geothermal water temperature must be greater than 280°F. The energy consumption for the 1976 calendar year was: heating--290,000 therms, processing-natural gas--4,394,326 therms, and oil, 816,081 gallons, at a total cost of $1,243,850. Natural gas availability is dependent upon weather conditions and gas utility contracts.

To avoid any possible contamination of the product by the geothermal fluid, or the need for treatment of the fluid, energy is supplied to the process via intermediate heat exchangers which could be either of the shell-and-tube design or the compact and versatile plate-type heat exchanger. Cost analysis for this study used the plate-type heat exchanger. The geothermal fluid passing through these exchangers will transfer energy to a secondary fluid, primarily water, which delivers the energy to the process. The secondary fluid, circulating in a closed system, then returns to the intermediate heat exchanger to be reheated. Energy requirements for the high-temperature processes (200°F or more) are satisfied by dropping the geothermal fluid temperature from 300°F to 190°F. The lower-temperature processes are then supplied partially by this cooled-off geothermal fluid and partially by fresh geothermal fluid.

All of the secondary heat exchangers would be housed in a separate, new structure adjacent to the plant, along with the pumping and control equipment.

A roughly 2,000-foot long pipeline would carry fresh geothermal fluid from the well field, on company-owned property, to the heat exchanger building and waste fluid would be carried back from the building to the injection well. With an anticipated temperature drop of 170°F for the geothermal fluid used to supply the 63.4 million Btu/hr needed for processing, roughly 370,000 lb/hr will be required. This should be readily available from two wells, with adequate margin for load variation or delivery rate fluctuation. The wells would be pumped to minimize temperature losses. A third well would be required for injection of the rejected fluid.

From the economic analysis for Ore-Ida Foods, Inc., a 30 percent ROI, or 3.6-year after-tax payback was calculated for a 15-year project life. The total after-tax dollars available at a 20 percent ROI for intangible drilling costs is $2.9 million. Considering the after-tax cost of drilling an 8,000-foot well, the company could afford to drill eight wells and one injection well. In other words, with a geothermal resource confidence level as low as 25 percent, Ore-Ida Foods could still realize a 20 percent ROI.

III. RESOURCE ASSESSMENT

A. Introduction

If geothermal energy is to be developed as a significant resource, it is necessary that it either be produced adjacent to or transported to areas of need. As yet, with the exception of electric power produced at The Geysers, the use of geothermal energy is restricted in the United States to within a very short distance of the production well. Today's technology and energy costs make it possible to deliver geothermal waters to distances up to 100 km depending upon the temperature of the water at the source, delivery point end-use, costs and availability of other energy supplies.

In vast regions of the western United States, geologic studies show that intermediate-temperature geothermal waters (90° to 150°C) can be located at depths ranging from 1 to 2 km. In the part of the region where space heating is becoming an ever-increasing burden, the possibility of using geothermal energy for industrial uses, for institutional heating, or for district heating is becoming increasingly attractive. This assessment points out localities where the geothermal potential may exist, outlines the geothermal occurrences as known to date, infers reservoir data by comparison with known geothermal reservoirs, develops preliminary cost data and acquaints potential industrial users with the possibility of utilizing geothermal energy.

Two areas chosen for study have known geothermal resources in potentially significant amounts and additionally are in regions with well-developed, agricultural-based economies. The Klamath Basin and Western Snake River Basin share many geologic characteristics. Both are within the Basin and Range geologic province, a large region taking in much of southeastern Oregon, southern Idaho, western Utah, northern Arizona, parts of eastern California and most of Nevada. The principal identifying characteristic is the tensional faulting that has broken the region into a series of linear valleys and mountain ranges. Other significant characteristics shared by the two areas are widespread late Cenozoic volcanism, lake basin sedimentation, and the presence of hundreds of thermal springs.

In the Klamath Basin there is a wealth of information on the location of near-surface geothermal waters and of practical methods of utilizing this resource, but little information on the deeper rocks and how they may be affecting the presence of the shallower geothermal waters.

In the Western Snake River Basin deep drilling for suspected occurrences of oil and natural gas have provided a general knowledge of the existence and depths of the deep potential geothermal reservoirs, but because the near-surface indications of hot waters are sparse, there has been little development of the type that is being practiced in the Klamath Basin.

Rationale for Selecting Geothermal Targets

Surface hot springs, warm-water wells, thermal gradients, water well temperature and regional geologic, hydrologic, and geophysical studies were all used to determine potential geothermal resource targets as shown on the individual resource assessment maps. In the Snake River Basin a higher-than-normal heat flow is present and favorable temperatures can be predicted at reasonable depths. The measured and projected geothermal gradients have been the main indicators of targets at shallower depths in both study areas.

By using the combination of measured and projected geothermal gradients, a total of several hundred data points were available in the study areas. Projected gradients were calculated from aquifer temperatures and depths recorded on drillers' logs for water wells. In most cases this method was limited to wells deeper than 50 m and in spite of inherent inaccuracies, the results have been quite useful. The projected gradients, when compared to measured gradients in nearby wells or the same well, were found to be reliable. Zones of higher-than-normal heat at shallower depth generally were found to be elongate and associated with fault zones that are known or inferred from geologic or geophysical studies.

B. Klamath Basin Assessment

    1. Introduction

    To determine the potential for increased utilization of natural hot water in parts of the Klamath Basin a growing list of published reports concerned with the geology, hydrology and geothermal resources have been reviewed. Interpretation of the information in the published reports, additional data from field examinations, and evaluation of hundreds of water well logs suggest several additional areas where adequate quantities of moderate-temperature water ranging from 40° to 100°C (100° to 210°F) may be found at reasonable depths from 500 to 1000 m (1,500 to 3,000 feet).

        a. Previous Work

        The geology of the area has been described in some detail by several reports including Newcomb and Hart (1958), Peterson and McIntyre (1970), and Sammel (1976). Groundwater resources in the Klamath Basin have been studied by Newcomb and Hart (1958), Illian (1970), and Leonard and Harris (1974). The geothermal resources in the Klamath Falls area have also been studied in some detail by Peterson and Groh (1967), Peterson and McIntyre (1970), Culver and others (1974), Sass and Sammel (1976), and Sammel (1976). These reports and others with some information about geology, hydrology, or geothermal resources are listed at the end of the report.

b. Geology

The geologic studies show that even though the stratigraphy is
not complex it is far from uniform. The structure is complex,
however, and makes the understanding of the hydrology difficult.

A summary of the geology by Peterson and Groh (1967) gives the
general picture and shows the Klamath Basin area to be underlain
by a sequence of Pliocene and Pleistocene rocks that includes a
lower unit composed of basaltic lava flows (0 to 250 m thick),
overlain by a volcanic-sedimentary unit, the Yonna Formation (50
to 300 m thick), which is in turn overlain by a thinner unit of
basaltic lava flows and breccias (5 to 30 m). As indicated,
thickness of the units and their lateral extent are not uniform
and the units are probably interfingered deposits of lakes and
streams that originated in a low relief terrain dominated by
contemporaneous basaltic eruptions during Pliocene time. The
Yonna Formation, volcanic and sedimentary rocks, are overlain
by a variable thickness of lacustrine and alluvial sediments
mainly in the structural valleys. The deeper basement rocks are
not known but a recent, deep, geothermal well test encountered
rocks similar to those of the Western Cascades (andesitic and
basaltic lava flows, vari-colored volcanic breccias, and tuffs).

Faulting, some of which occurred in late Pleistocene time, has
broken the whole Klamath Basin into a complex of northwest-
trending fault block ridges (horsts) and intervening down-dropped
(graben) valleys. Smaller tilted fault block protrude above the
alluviated floors of the valleys.

The pattern of hot springs, hot-water wells, and hydrothermally
altered rocks indicates geothermal activity over a long period of
time at many places in the Klamath Basin including the city of
Klamath Falls, Olene Gap, southwest Klamath Hills, and near Lorella
in the Langell Valley.

Most of the geothermal anomalies appear as narrow, elongate zones
paralleling major faults or fault blocks within the basin. This
has led to one interpretation that the hot waters at Klamath Falls
originate from deep circulation of meteoric waters with convective
transfer of heat and fluid from depth through permeable zones along
some of the major faults. Other interpretations have suggested a
magmatic heat source.

The latest study, U.S. Geological Survey WRI 76-127, "Hydrogeologic
Reconnaissance of the Geothermal Area Near Klamath Falls, Oregon,"
by E. A. Sammel (1976), concludes that the Klamath Falls area is
underlain by an intermediate-temperature (90° to 130°C) convective
geothermal system. This interpretation is based primarily on the
geochemical temperature indicators (Renner and others, 1975) which
the water in the reservoir reaches a temperature of 130°C. Based
on that reservoir temperature, Sammel (1976) concludes that the

thermal waters in the area are produced by deep circulation along the fault zones to depths of 3 to 4.3 km (10,000 to 14,000 feet) in a region of a normal geothermal gradient of 30° to 40°C per km. Based on the assumption that the hot water is produced through the mechanism of deep circulation in the fault zones, Sammel (1976) concludes that the hot waters are generally restricted to the three areas where they are now known, the Klamath Falls/Altamont, Klamath Hills, and Olene Gap regions.

The authors of this report believe the hot waters are more abundant and widespread than does Sammel (1976) and base the assumption on the belief that the geothermal gradient and therefore the heat flow of the region is much higher than the 30° to 40°C per km regional gradient reported by Sammel (1976), and Sass and Sammel (1976). From this and other studies of the Klamath Basin made by the authors it appears the regional gradient is nearer 75°C per km. If the regional gradient is in the range of 75°C per km, water with sufficient temperature for space heating (45° to 50°C) can be expected to occur regionally at depths of 0.5 to 0.6 km (1,500 to 2,000 feet). Zones of upswelling higher temperature waters (90° to 100°C) should be expected adjacent to faults. And, it is probable that deeper drilling to depths of 1.5 to 2 km will intersect waters at least as high as 130°C, the reported reservoir base temperature in the region.

Even though the Klamath Basin geothermal systems may have only marginal potential value for generating electricity, they do have a very great potential for home heating and industrial applications. Calculated estimates by White and Williams (1975) of the thermal energy that can be applied directly to its intended nonelectric use (assuming 25 percent of the stored energy recovered at the surface and the efficiency of utilization also 25 percent) is 1.5×10^{18} calories and if this useable heat were to be supplied by electrical energy it would require 1,990 MW-century. The heat content in the shallow-water system is estimated to be in the range of 12×10^{18} calories and could be one of the largest in the United States (Sammel, 1976 and White and Williams, 1975).

c. Geothermal Potential

To discuss the geothermal potential in an orderly way, eight subareas have been designated as shown on the index map, Figure 1. The most promising areas for additional hot-water resources border or are extensions of the three principal known geothermal areas (Klamath Falls, Klamath Hills and Olene Gap); however, several other targets with promising potential are indicated on the individual maps and discussed in the subarea reports.

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Figure 1.

Sub-area Index Map of Klamath County

1 Klamath Falls – North Altamont – Pelican City
2 South Altamont – Miller Hill
3 Klamath Hills – Spring Lake Valley
4 Olene Gap – Poe Valley
5 Merrill – Malin
6 Keno – Klamath River
7 Langell Valley
8 Sprague River Valley

Known Geothermal Resource area

13
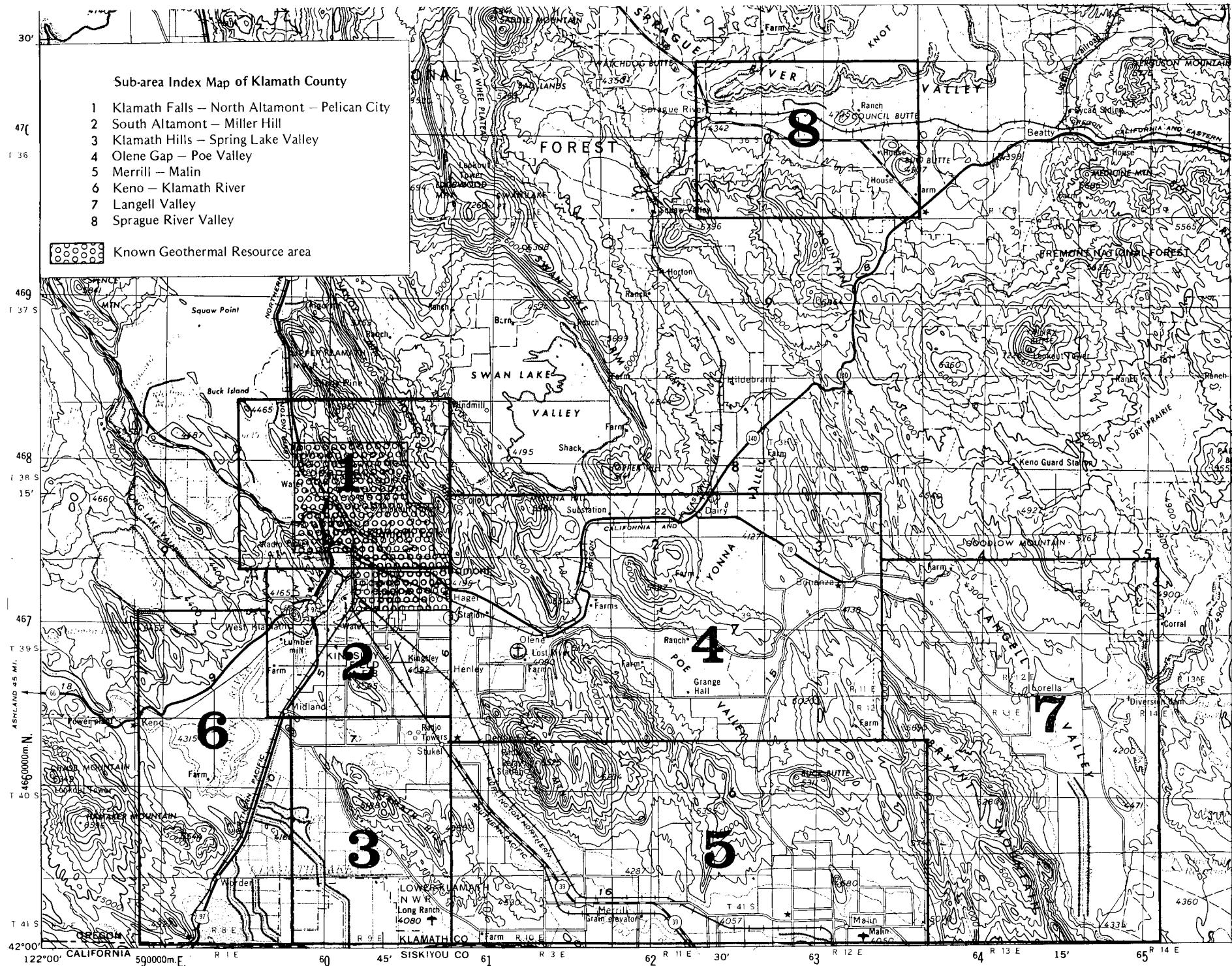
2. Subarea Assessment

   a. Klamath Falls/North Altamont/Pelican City

   The subarea designated at Klamath Falls/North Altamont/Pelican
   City contains about 130 km² (50 square miles), extends eastward
   from Upper Klamath Lake to Hogback Mountain on the east, and
   from Cove Point/Wocus southward to Lake Ewauna and Altamont
   (Figure 2).

   The urban area of Klamath Falls which contains the core of the
   well-known geothermal resource has not been tabulated in detail
   for this project as this has been done by Culver and others (1974).
   Extensions to the northwest, east and south of the urban area that
   have potential as sources of hot water for the agribusiness indus-
   try are shown by pattern on Figure 2.

   The area east of Klamath Falls adjacent to the Old Fort Road for
   about 2 km has some wells that show above-normal temperatures and
   gradients as well as hydrothermal rock alteration. This zone
   which extends east into the SW 1/4 sec. 22 and the W 1/2 of sec.
   27, is considered to have a better-than-average potential for
   developing hot water.

   A recent well drilled at the north end of Summers Lane in the
   SE 1/4 of sec. 34, produces 70°C water from 468 m and is used to
   heat the Shadow Hills apartment complex. This extends the known
   resource zone to the southeast. Another well just west of
   Washburn Way in the NE 1/4 sec. 4, T. 39 S., R. 9 E., extends
   the developed hot-water zone to the south. This well produces
   46°C water from 460 m depth and furnishes heat to the large May-
   wood Industries building.

   The latest detailed study by the U.S. Geological Survey,
   WRI 76-127, "Hydrologic Reconnaissance of the Geothermal Area
   Near Klamath Falls, Oregon," by E. A. Sammel shows a broad zone
   including the area south of Klamath Falls from Lake Ewauna to
   Altamont within a 30°C isotherm where maximum temperatures from
   wells are 30°C (86°F) or above at moderate depths.

   The area northwest of the known geothermal wells at Oregon Insti-
   tute of Technology and the Presbyterian Intercommunity Hospital
   is essentially untested; however, similar geology and rock altera-
   tion indicates that this zone extends as far as the SW 1/4 of sec.
   17, T. 38 S., R. 9 E., and is considered to be a good target.

   If an agribusiness were to consider locating in the Pelican City/
   Industrial Park area, pumping of hot water from known geothermal
   sources nearby appears to be feasible.

KLAMATH FALLS - N. ALTAMONT - PELICAN CITY SUBAREA
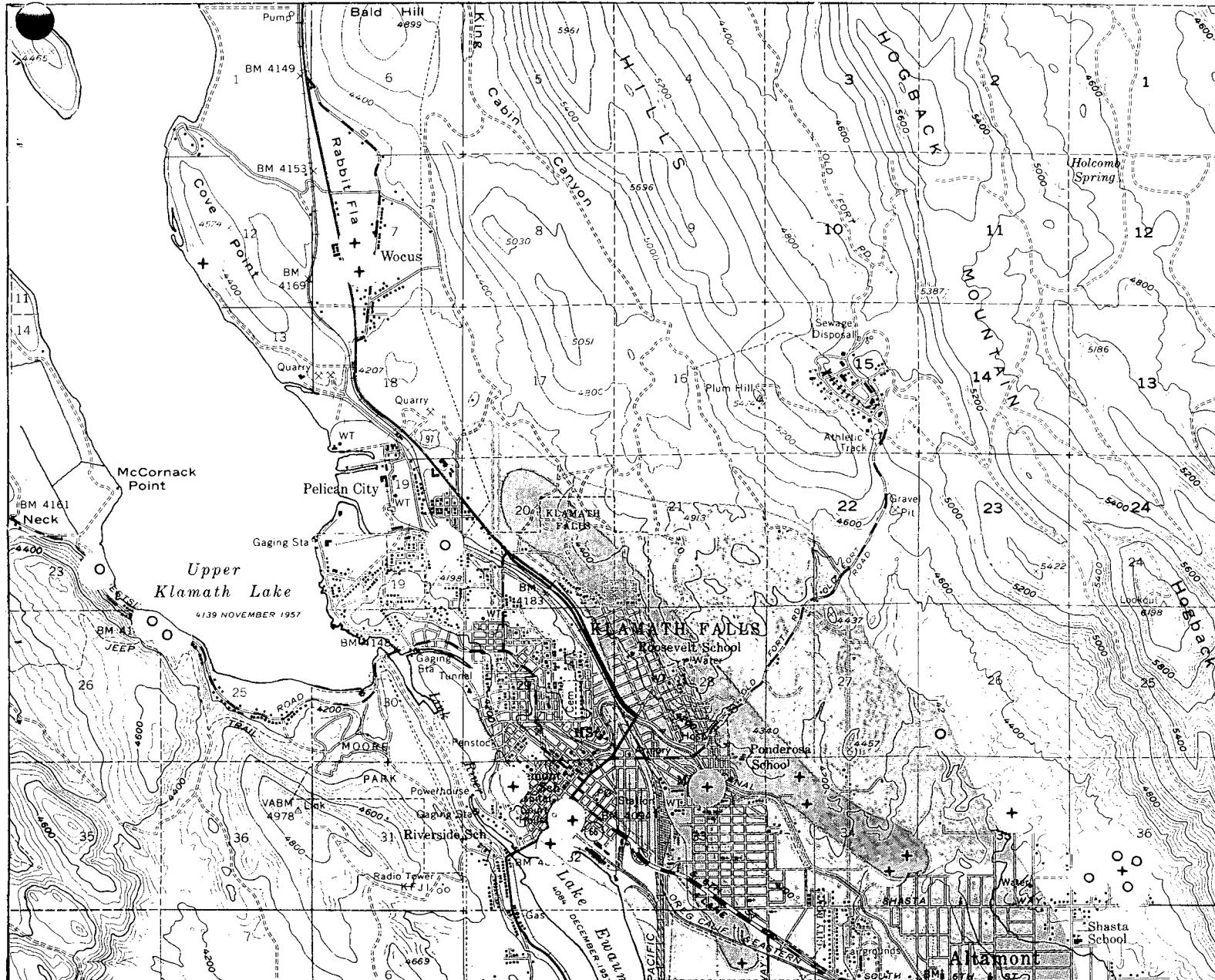
LEGEND

Greater than average potential for
hot water from 50°C to 100°C at depths
of 500 to 1,000 m.

Area where geothermal water has been
developed for industrial or home heating use.

DRILL HOLE WITH GEOTHERMAL GRADIENT

O   Gradient ≤ 100°C/km

+   Gradient > 100°C/km

Figure 2.

b. South Altamont/Miller Hill

The South Altamont/Miller Hill area covers about 100 km^2 (40 square miles) directly south of Klamath Falls and is almost all within T. 39 S., R. 9 E. Lake Ewauna and the headwaters of the Klamath River are in the northwest part, Midland and Miller Hill along the south boundary (Figure 3).

Several sites within this area appear to have above-average potential for reaching hot water in the range of 40° to 100°C at depths of less than 1000 m. One of the most promising is a narrow northwest-trending zone about 4 km long that extends from the KLAD radio transmitter station southeastward through Railroad Hill in sec. 9 to the Altamont/Summers Lane junction with Johns Avenue.

The other area already tested is along the northeast margin of the map extending southeastward beyond Wiard Park to the Hager area. The Mazama School well produces water of 60°C from 300 m within this zone. The south end of Miller Hill has also been tested and wells for the Falcon Heights subdivision in sec. 33 and others have water temperatures of near 40°C at 300 m and less. A shallow well at Midland in sec. 36, T. 39 S., R. 8 E. is also reported as warm and this area may have some potential. In the northwest corner of the area some recent wells in the north part of Stewart-Lennox and one at the Junction of Highway 66 and 97 show gradients of 110° to 150°C/km and may have some potential; however, this area will need further evaluation.

c. Klamath Hills/Spring Lake Valley

Included in this subarea is the well-known geothermal zone of the southwest flank of the Klamath Hills, the Spring Lake Valley to the north and a large part of the Lower Klamath Lake to the southwest (Figure 4). The hot-water zone shown on the area map is lens shaped, about 7 km long and at its widest point, near the center of the zone in sec. 27, 34, T. 40 S., R. 9 E., it is about 1-1/2 km wide. It narrows in both directions to about 1/2 km. At least four more successful hot wells have been drilled in 1976 in the hottest zone. While these wells have not been completely tested, all are estimated to be capable of producing 1,000 gpm of 80° to 90°C water. Other than the main producing zone some shallow wells along the north flank of the Klamath Hills are reported as warm. The only other area of interest is in the north where the southern extension of the Miller Hill warm-water zone extends into the Spring Lake Valley in secs. 3 and 4, T. 40 S., R. 9 E.

The proven resource of relatively large volumes of hot water in this agricultural area make it one of the prime areas for development.

S. ALTAMONT-MILLER HILL
SUBAREA
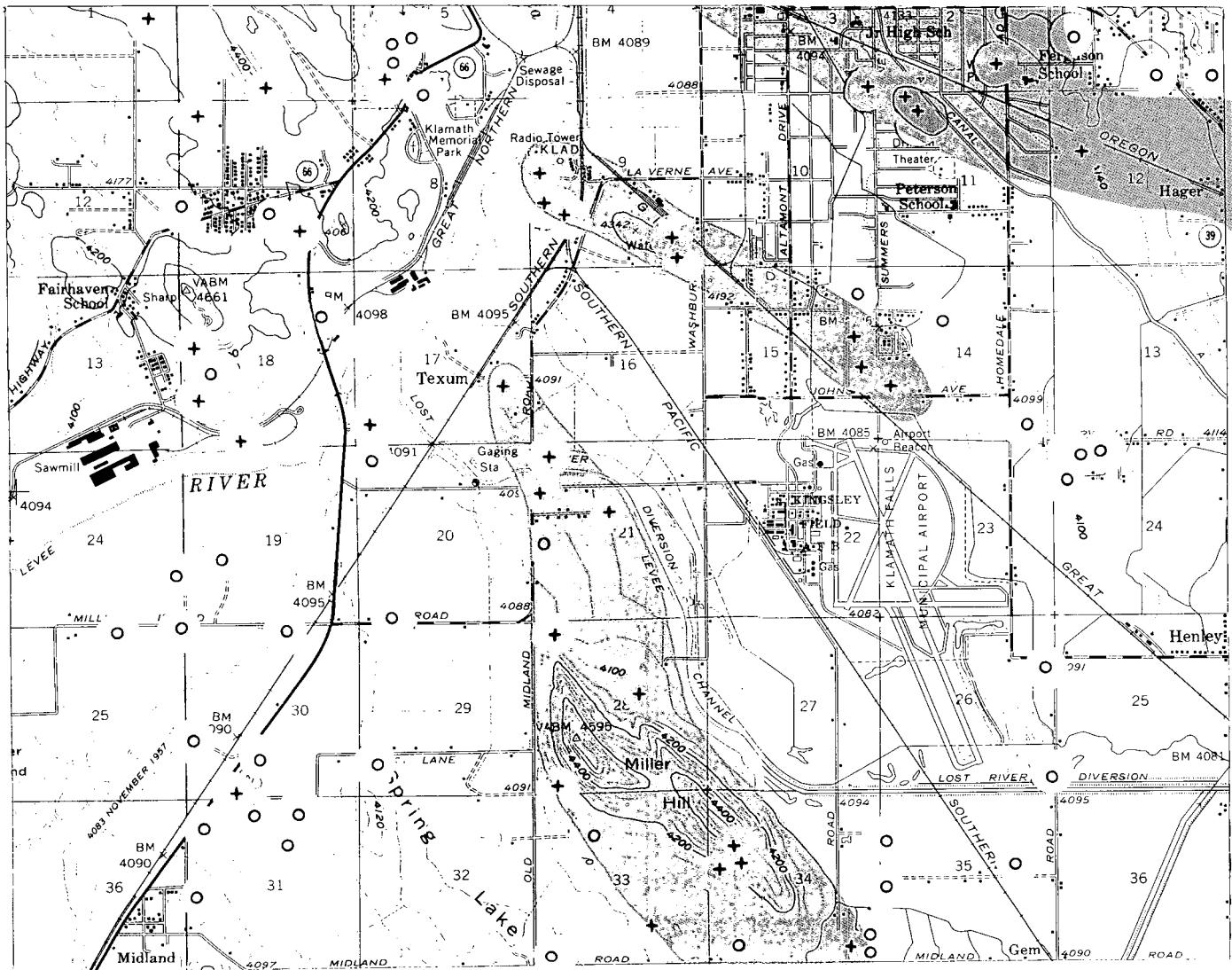
LEGEND

☐ Greater than average potential for hot water from 50°C to 100°C at depths of 500 to 1,000 m.

▨ Area where geothermal water has been developed for industrial or home heating use.

DRILL HOLE WITH GEOTHERMAL GRADIENT

O Gradient ≤ 100°C/km

+ Gradient > 100°C/km

Figure 3.

KLAMATH HILLS-SPRING LAKE VALLEY SUBAREA
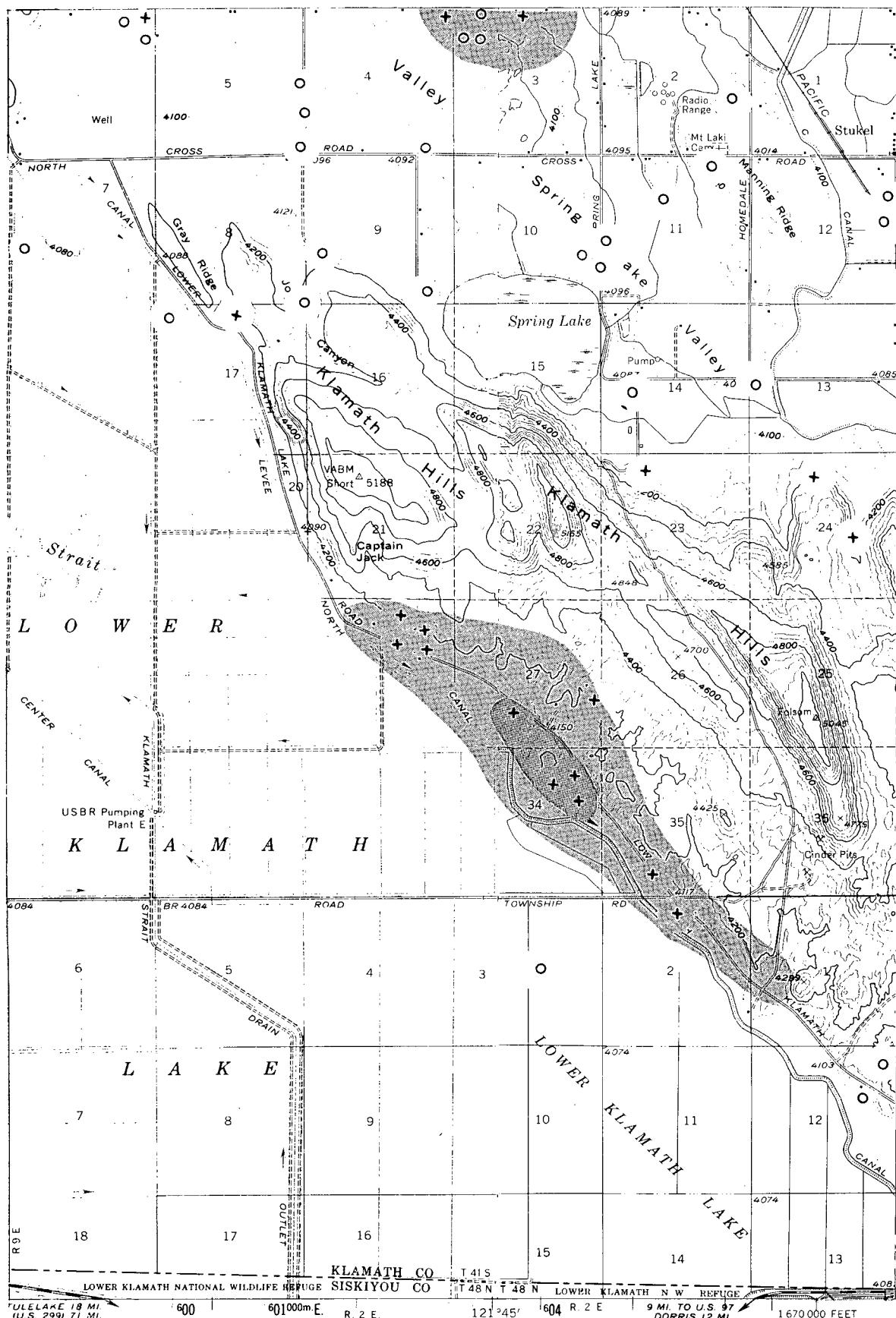
LEGEND

□ Greater than average potential for hot water from 50°C to 100°C at depths of 500 to 1,000 m.

■ Area where geothermal water has been developed for industrial or home heating use.

DRILL HOLE WITH GEOTHERMAL GRADIENT

O Gradient ≤ 100°C/km

+ Gradient > 100°C/km

18

Figure 4.

d. Olene Gap/Poe Valley

The Olene Gap/Poe Valley subarea includes the northwest part of Stukel Mountain, the Pine Grove area, Olene, all of Poe Valley, and the southern part of the Yonna Valley as far east as Bonanza as outlined on the subarea map (Figure 5).

A review of the geology, surface, and subsurface temperatures indicate that the highest potential for geothermal fluids is in the Olene Gap area. The hot springs there were recently measured for temperature and flow while the Lost River was at its lowest level and most of the spring orifices were exposed in the river bed. Temperatures measured ranged from 70° to 81°C at six separate spring vents on the south bank of the river, south of the bridge, and the largest spring in the concrete culvert north of the flume on the north bank of the river had the highest temperature at 87°C. A traverse of the north shore of the river shows several areas of warm ground between the bridge and flume. The total volume of water flowing from the springs at Olene Gap was estimated to be from 30 to 50 gal/min. Water well projected thermal gradients both east and southwest of the gap indicate that the geothermal anomaly extends some distance to the east and also to the south.

The next best potential area is connected with the Olene Gap anomaly and extends south and westward in a zone one-half to one mile wide surrounding Nuss Lake and extends west and south around the northwest point of Stukel Mountain in sec. 32, T. 39 S., R. 10 E. High projected gradients in water wells (100° to 500°C/km) occur on the west side of Stukel Mountain between Dehlinger and Wilson Bridge. High gradients are also present in the zone both west and north of Nuss Lake to Crystal Springs and Olene.

Another area that shows a higher-than-normal geothermal potential is located at the south end of Hogback Mountain straddling the junction of Highway 140 and the Merrill Highway in secs. 6 and 7, T. 39 S., R. 10 E. This appears to be the southeasternmost extension of the Klamath Falls geothermal zone.

Two smaller areas that need more information points but that may have some potential are located in the northeast part of Poe Valley on the west and south flank of the faulted volcano that separates the Poe and Yonna Valleys.

e. Subarea Five, Merrill/Malin

The Merrill/Malin area includes most of the agricultural land north of the California line from Bryant Mountain east of Malin to the eastern part of the Klamath Hills on the west. It also extends north and west on both sides of Lost River along the southwest flank of Stukel Mountain.

OLENE GAP-POE VALLEY SUBAREA
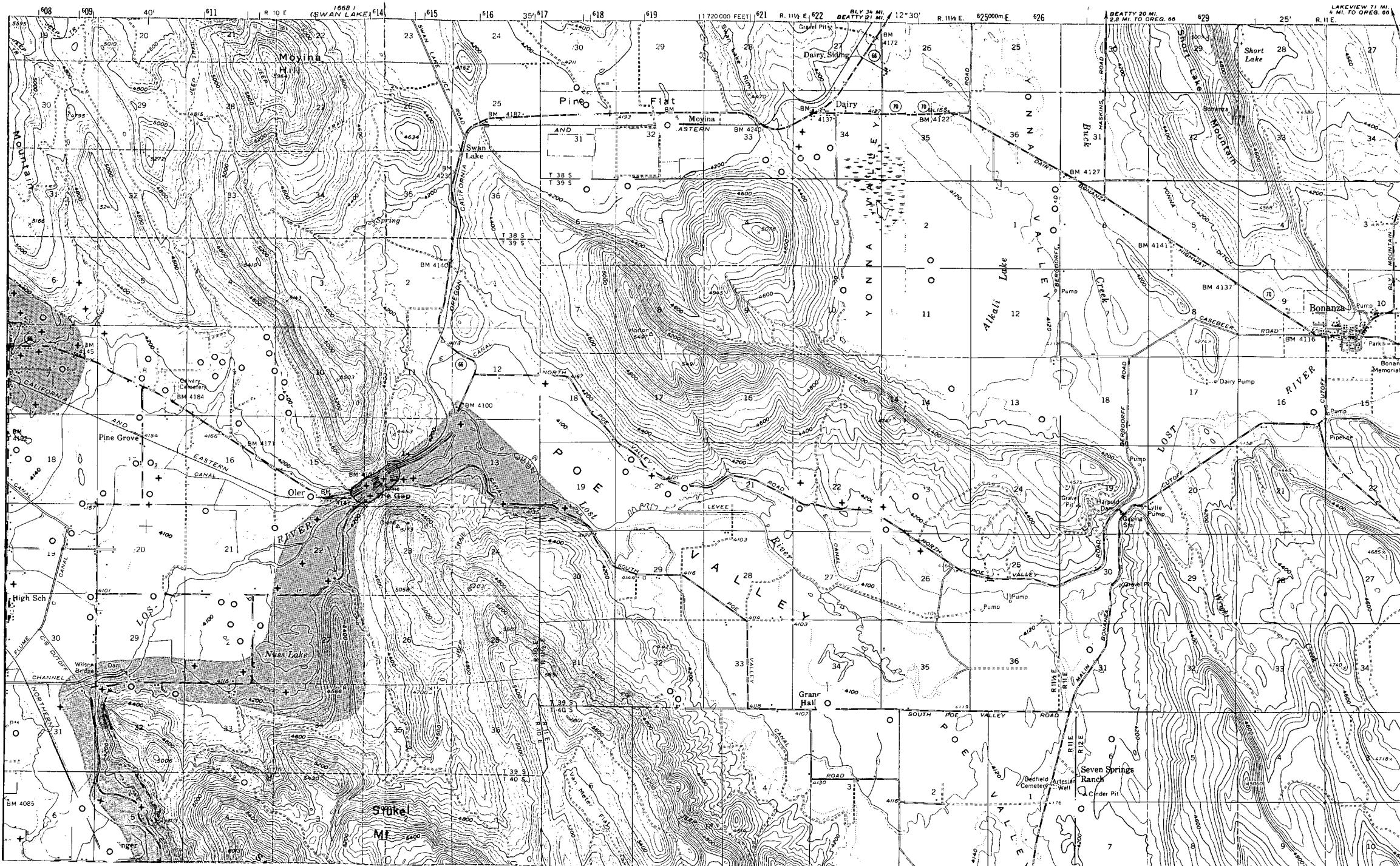
LEGEND

Greater than average potential for
hot water from 50°C to 100°C at depths
of 500 to 1,000 m.

Area where geothermal water has been
developed for industrial or home heating use.

DRILL HOLE WITH GEOTHERMAL GRADIENT

O Gradient ≤ 100°C/km

+ Gradient > 100°C/km

Figure 5.

A study of springs and well logs indicates several areas of moderate-temperature (50° to 100°C) geothermal potential and these are outlined on the sketch map (Figure 6).

They are listed here in the authors' interpreted order of highest potential. No. 1 - An elongate area near the northwest corner of the map along Hill Road and the west flanks of Stukel Mountain in secs. 8, 9, and 16, T. 40 S., R. 10 E. Well logs report temperatures of 22° to 30°C at depths of 55 to 75 m. Projected gradients for this area range from 133° to 290°C/km.

No. 2 - An area on the south side of Stukel Mountain in secs. 25, 26, T. 40 S., R. 10 E., and extending eastward and southward to Adams Point half way between Merrill and Malin. The most promising part of this area is the northwest part where projected gradients range from 100° to 218°C/km in several wells.

No. 3 - Three small areas northwest and south of Merrill in the easternmost part of the Klamath Hills show higher than normal gradients 130° to 160°C/km. They also produce large water volumes and the potential for a geothermal resource in the range of 50° to 70°C is above average. These could represent a continuation of the geothermal zone along the south side of the Klamath Hills.

f. Keno/Klamath River

This area includes large blocks of agricultural land flanking the headwaters of the Klamath River southwest of Klamath Falls and east of Keno and the western part of Lower Klamath Lake (Figure 7). The only part of this large area that shows thermal gradients over 100°C/km is in the northeast corner in secs. 14 and 23, T. 39 S., R. 8 E., where several wells drilled in 1976 in the Lawanda Hills Subdivision produce water from 18° to 22°C at depths ranging from 50 to 100 m. Gradients in this area range from 95° to 171°C/km. Water volumes reported are from 20 to 100 gal/min. This small area needs to be evaluated further. Another single anomalous water well with a measured gradient of 150°C/km is reported by Sammel (1976) in sec. 10, T. 40 S., R. 8 E. Otherwise a general lack of information in the western and southern part of the area from Keno to the California border prevents a meaningful evaluation.

g. Langell Valley

The Langell Valley subarea covers about 260 km^2 and is basically the broad northwest-trending valley of the Lost River from where it enters Oregon at the south to Bonanza in the northwest (Figure 8).

A review of water well logs and other data shows the temperature of the shallow groundwater to be generally normal or below normal, except for three relatively small elongate zones in the central and south part of the valley.

MERRILL-MALIN SUBAREA
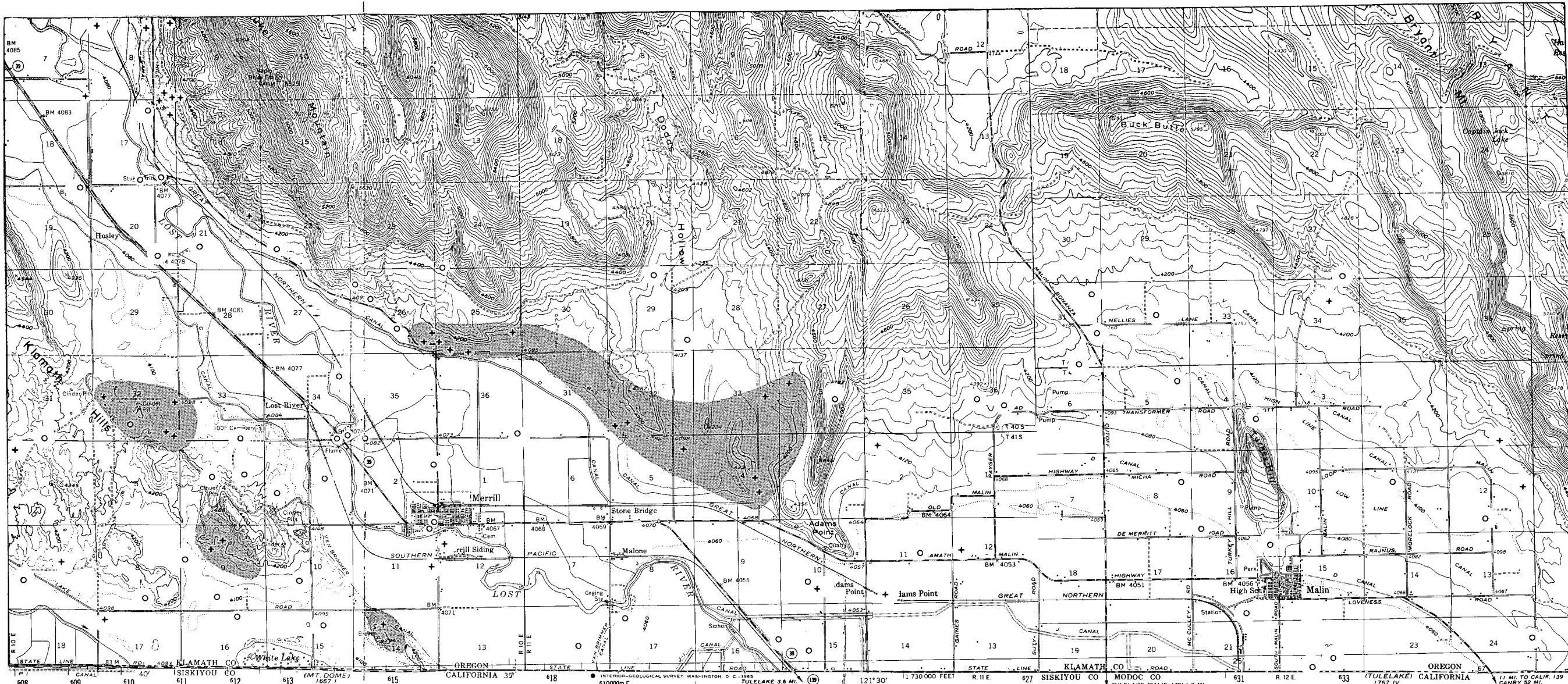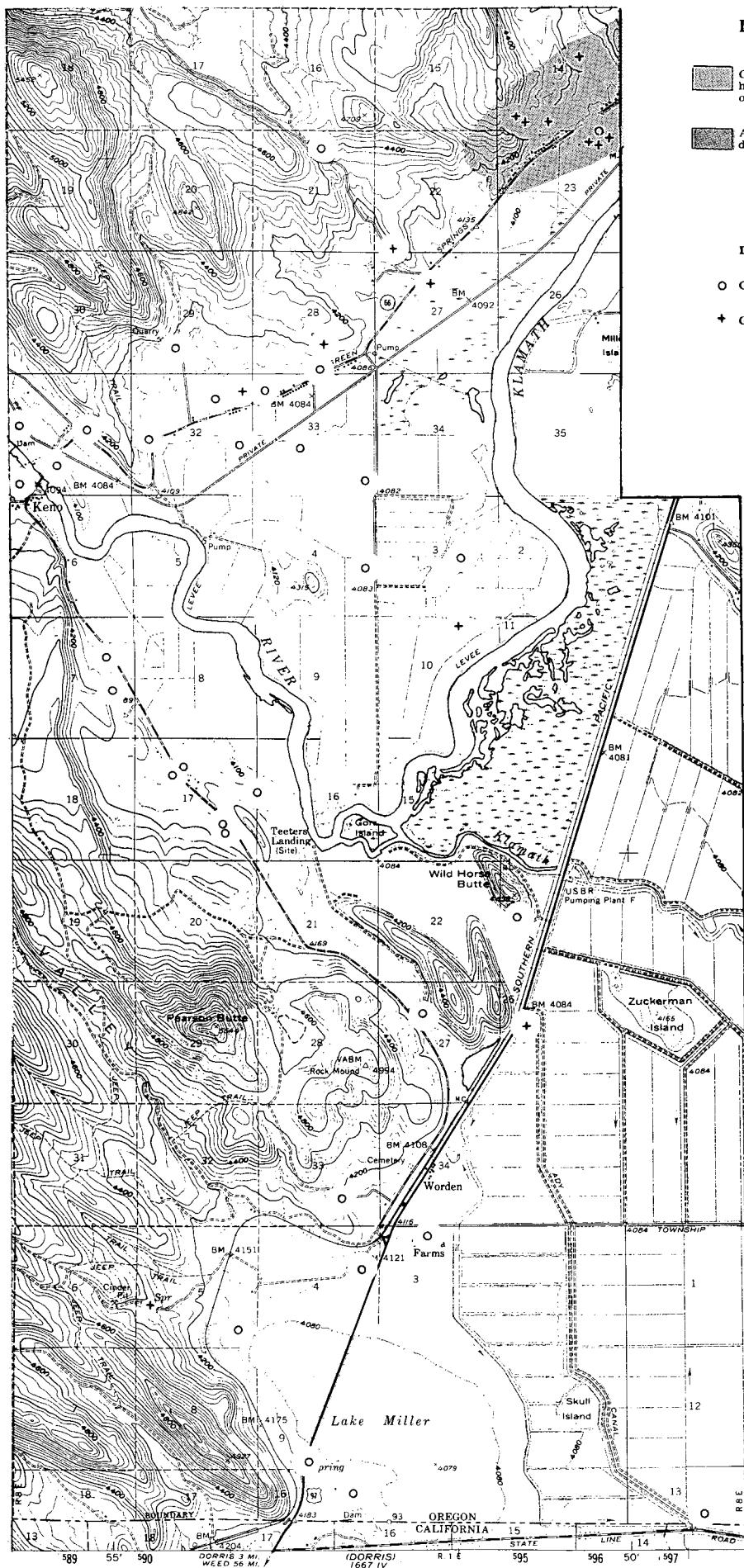
LEGEND

OREGON

QUADRANGLE LOCATION

Greater than average potential for hot water from 50°C to 100°C at depths of 500 to 1,000 m.

Area where geothermal water has been developed for industrial or home heating use.

DRILL HOLE WITH GEOTHERMAL GRADIENT

O   Gradient ≤ 100°C/km

+   Gradient > 100°C/km

Figure 6.

KENO-KLAMATH RIVER SUBAREA

Figure 7.

LANGELL VALLEY SUBAREA

LEGEND

Greater than average potential for hot water from 50°C to 100°C at depths of 500 to 1,000 m.

Area where geothermal water has been developed for industrial or home heating use.

DRILL HOLE WITH GEOTHERMAL GRADIENT

O   Gradient < 100°C/km

+   Gradient > 100°C/km
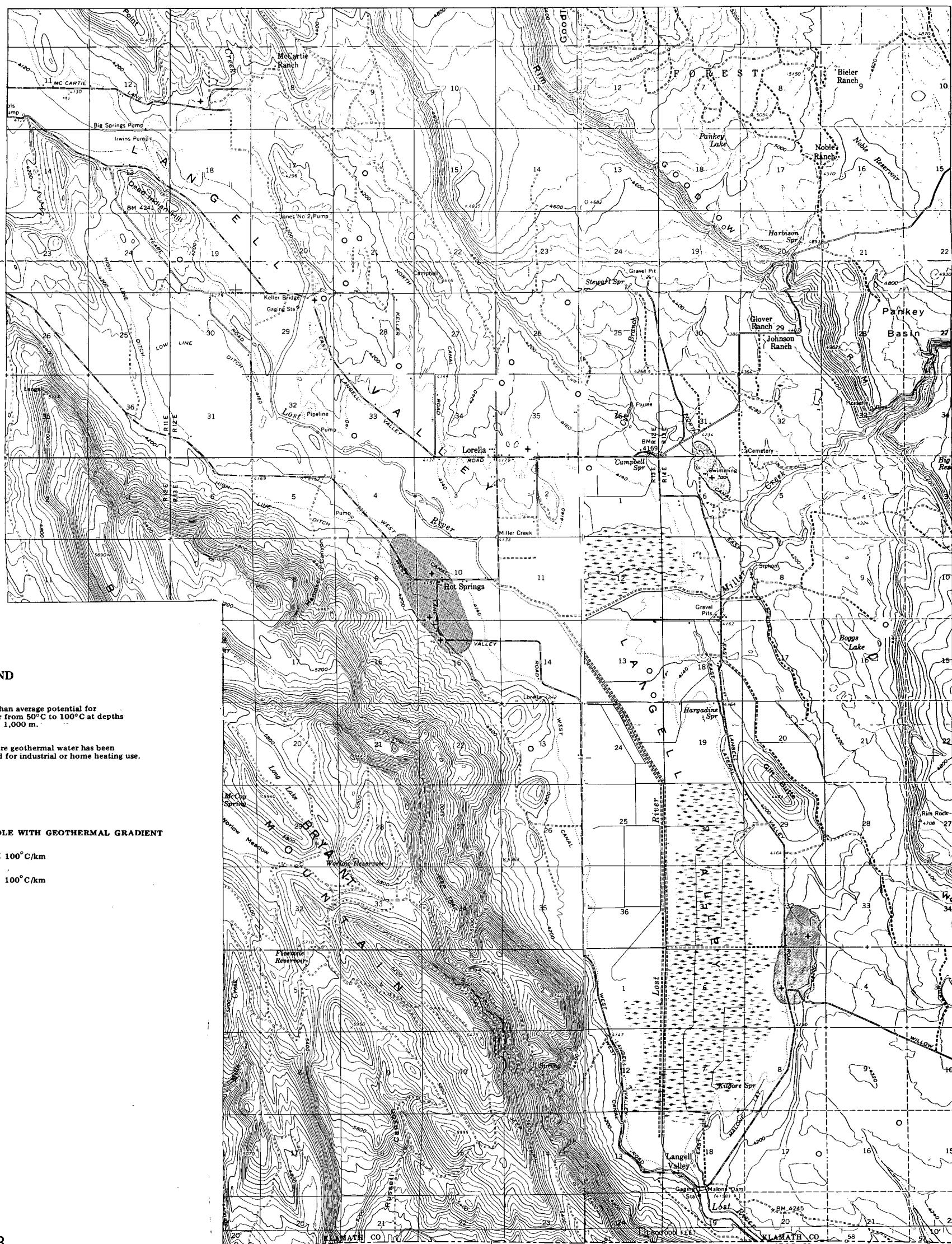
Figure 8.

The highest potential for geothermal fluids is in a narrow northwest-trending zone that includes the Turner or Big Hot Spring southwest of Lorella. This spring is reported to flow 40 gal/min of 61°C water.

Another area of higher-than-normal heat flow is located about three miles east of Lorella where a warm spring (Wilkerson or Patuchek) with 24°C water flows at 25 gal/min.

The only other area of questionable potential is in the south part of Langell Valley and is indicated by wells in sec. 32, T. 40 S., R. 13 E., and sec. 5, T. 41 S., R. 13 E., with gradients of 151° and 240°C/km. There are a few other scattered wells throughout the valley with thermal gradients above 100°C but with the few points of information available no meaningful predictions about hot-water potential can be made.

h. Sprague River Valley

The subarea designated as the Sprague River is all of T. 36 S., R. 12 E., and all but six square miles of T. 36 S., R. 11 E. (Figure 9). Newcomb and Hart (1958) reported wells with above-normal temperatures in the Sprague River Valley east of the town of Sprague River. A review of water well logs show some projected gradients of 100°C/km but a majority of the information indicates a less-than-average potential for reaching favorable water temperatures at a depth of less than 1 km; however, there are no deep tests to help in evaluating this subarea at the present time.

C. Western Snake River Basin Assessment

1. Introduction

The presence of hot springs and of hot irrigation wells around the margins of the Western Snake River Basin indicate the presence of a considerable untapped reserve of geothermal energy underlying the region. Figure 10 shows the location and extent of the study area, the pattern of faulting and the known thermal springs and wells. The agribusiness industry consumes considerable quantities of relative low-temperature heat in the range of 60° to 150°C (Reistad, 1975). If geothermal waters could be utilized for a portion of these energy requirements, a major savings in fossil fuels could be achieved by the region. Additionally, geothermal resources could provide for a reliable energy source at stable prices assuring the economy of the region a good competitive position against other areas that are facing rising prices of fossil fuels. The key to this utilization is knowledge of the location, temperature and quality of the resource.

The primary factors to be considered here are the location, depth to the reservoirs, temperature, well productivity, and cost of production. This study attempts to provide a geologic background of this information so decisions can be made to explore with a knowledge of all of the geologic information available at this time.

SPRAGUE RIVER VALLEY SUBAREA
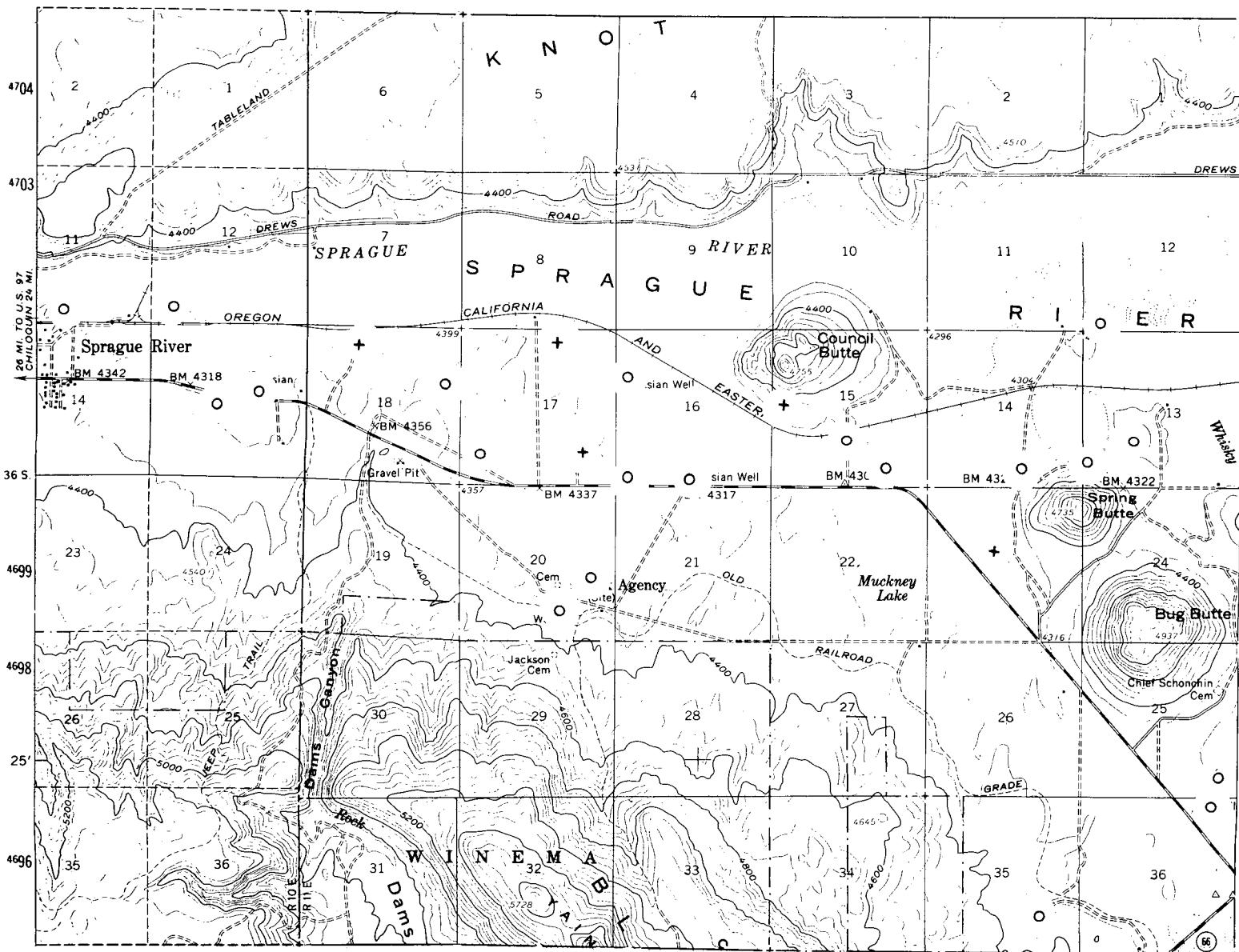
LEGEND

DRILL HOLE WITH GEOTHERMAL GRADIENT

O   Gradient ≤ 100°C/km

+   Gradient > 100°C/km

a. Previous Work

Corcoran and others (1962) mapped the geology of Mitchell Butte 30-min. topographic quadrangle and in doing so summarized the earlier work in the region and established many of the formation's names that are now used. Kittleman and others (1965, 1967) and Kittleman (1973) also published a geologic map of the region covering slightly more area than Corcoran. Newton and Corcoran (1963) prepared a reconnaissance map of the Western Snake River Basin and correlated the subsurface geology across the region using the cuttings and electric logs from 20 exploratory oil and gas wells. Their work along with logs from a few wells drilled later have been used to establish the geologic conditions of the deeper part of the basin. Bowen and Blackwell (1975) published the first geothermal study of the area which has been used extensively in preparing this report. Geophysical studies have been made in the area by Long, Hoover and Bramsoe (1975), who produced a map showing apparent electrical resistivities at specific frequencies. Couch (1977) and Couch and Baker (1977) published the results of gravity and seismic studies in the area. The study by Couch (1977) summarized both the gravity and seismic studies, presented a fault map of the region and synthetic cross-sections for a region south of Vale. The gravity data in particular seems to correlate the surface and subsurface geologic studies as it shows nearly all the thermal springs to be in zones of high gravity gradient, a characterization of faults. This relationship of faulting with thermal springs is shown in Figure 10.

b. Geology

The Western Snake River Basin is part of a much larger structural depression known as the Snake River Plain, that extends eastward from the Oregon border across southern Idaho to Yellowstone Park in Wyoming. The western part is mainly filled with fine-grained nonmarine sedimentary rocks with interbedded sequences of lava flows. The basin has been interpreted by some as a large complex graben with bounding normal faults. Figure 11 shows the general stratigraphy and some of the interpreted structure in the study area. Basaltic lava flows (Owyhee Basalt), the lowermost rocks of interest are Middle Miocene in age and correlated with the Columbia River Basalt. Above the Owyhee Basalt are lacustrine and fluvial sedimentary rocks of the Dear Butte Formation and Kern Basin Formation. Another sequence of basaltic lava flows, the Grassy Mountain Basalt, is overlain by Pliocene lake sediments of the Chalk Butte Formation, which are the predominant surface rock type. Regional dips of the layered rocks are generally at low angles to the east or toward the center of the basin. Estimated thickness of formations and their depth below the surface is portrayed in Figure 11.

Western Snake River Basin

– – Faults as indicated by
geophysical studies, Couch, 1977.

═══ Faults as indicated by geologic
inference.

(H) Hot spring or hot flowing well

Figure 10.

OREGON   IDAHO

Vale

Ontario   New Plymouth

CHALK BUTTE FORMATION

GRASSY MOUNTAIN BASALT

KERN BASIN FORMATION

DEER BUTTE FORMATION

OWYHEE BASALT

Vertical Exaggeration 4:1

1 Km

2 Km
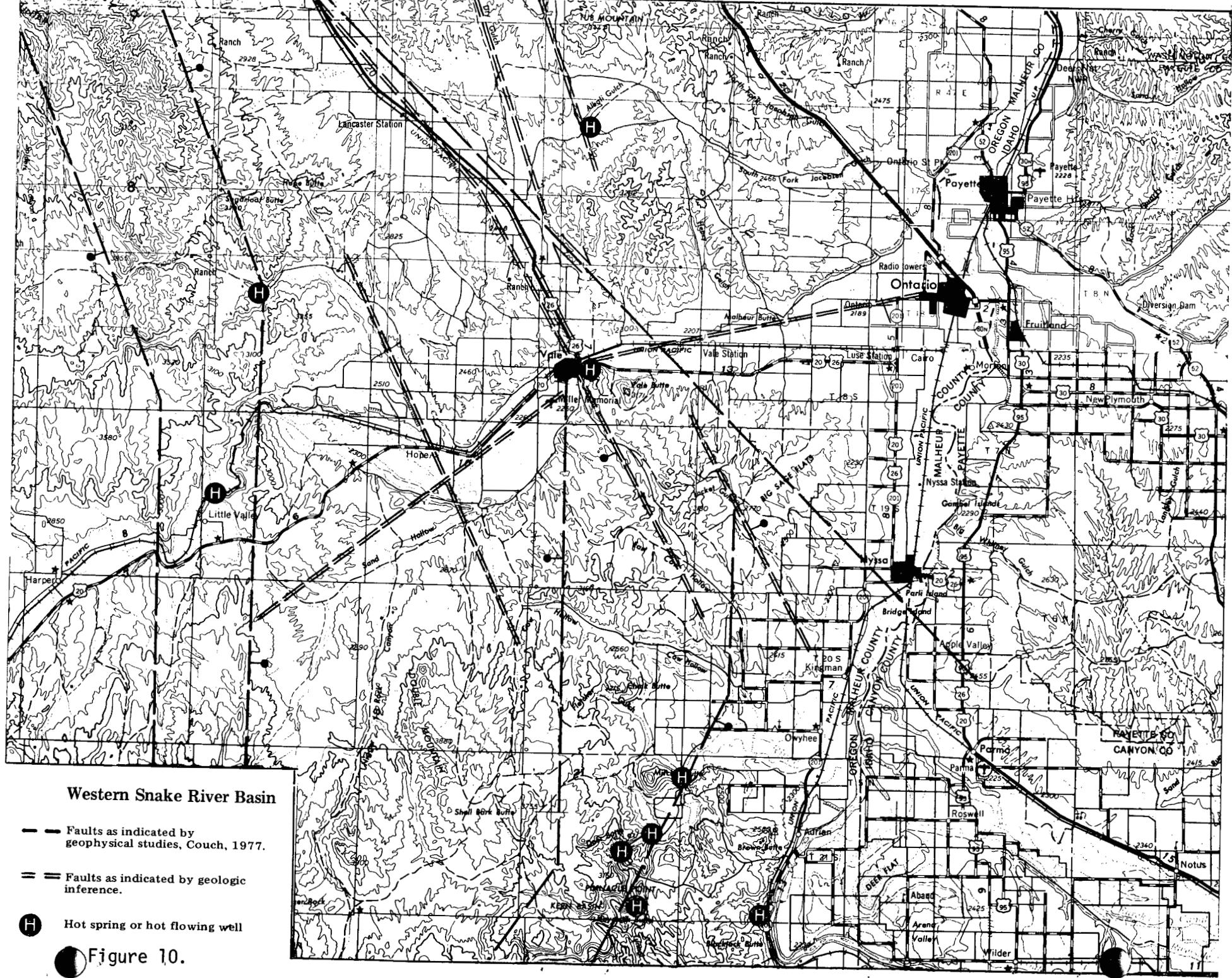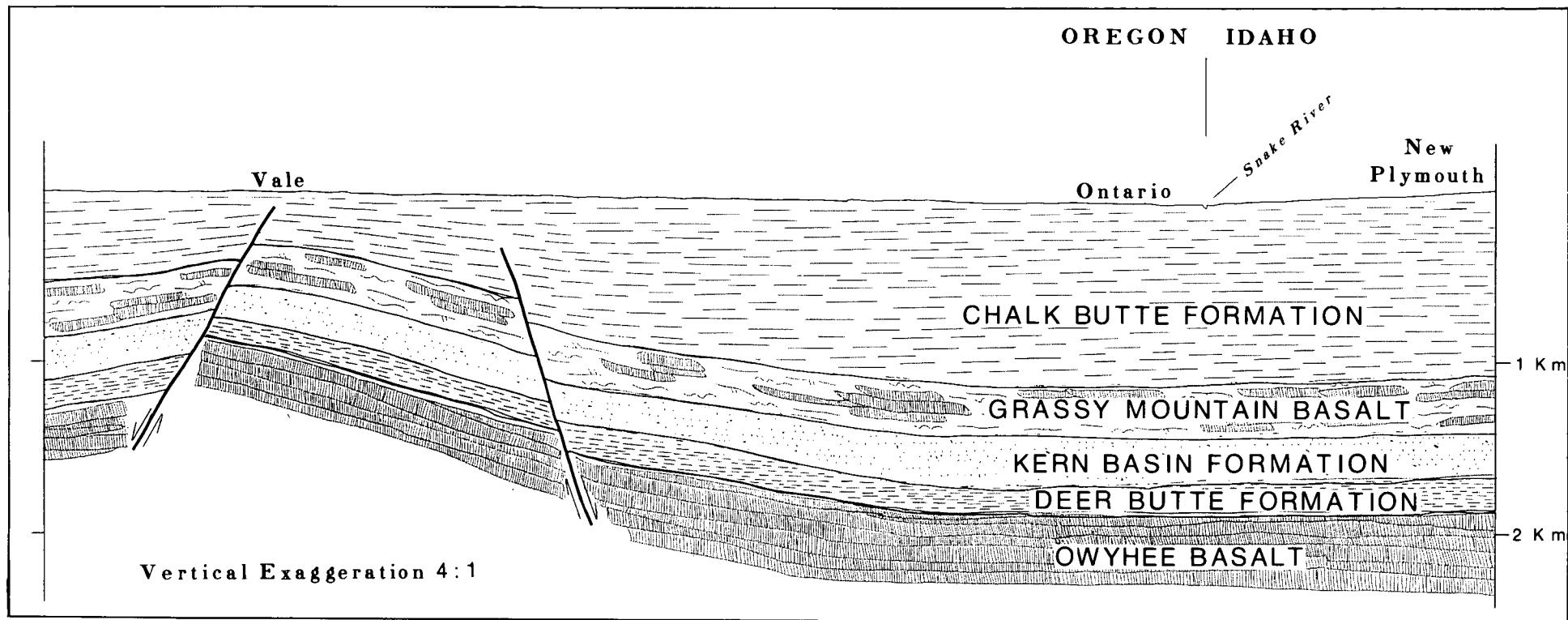
This cross section shows the relationship of the geologic structure and stratigraphy underlying the Western Snake River Basin study area. Owyhee Basalt and Grassy Mountain Basalt are considered to be the principal reservoir rocks in the region as they are the only ones having the porosity and permeability that will permit large withdrawals of water necessary to support space heating or process-heating uses. The fault zone at Vale opens a path of migration for geothermal fluids from underlying reservoirs to near the surface.

Figure 11.

c. Geothermal Potential

A number of conditions must exist if a geothermal deposit is to
be economically viable: 1) it must be of sufficient temperature
for its intended use; for electric power production temperatures
should be 150°C or greater. For space heating, temperatures of
50° to 150°C are useful, depending upon the particular use.
2) There must be a sufficient volume of geothermal fluid in the
reservoir to maintain production for 30 to 50 years, or there
must be hydrologic conditions that allow recharge of the reser-
voir. 3) The system must be confined by a relatively impermeable
barrier so a trap is formed, thereby allowing the fluids to
accumulate.

So far there has been no production of geothermal waters in the
region except for a few shallow wells near Vale Hot Springs; how-
ever, the presence of other hot springs and warm-water wells in
various parts of the area, along with the background knowledge of
the subsurface geology from the oil and gas tests drilled in the
basin, indicate that the required conditions for nonelectric uti-
lization outlined above are present. A detailed discussion of
the individual thermal water occurrences and interpreted geother-
mal targets is made in the individual subarea resource assessments.

In addition to the specific geothermal targets associated with
faults and outlined on the subarea maps, the generally higher-than-
normal regional heat flow makes the feasibility of locating hot
water most anywhere in the study area possible. Fluids at useable
temperatures can probably be located by drilling to either the
Grassy Mountain or the Owyhee Basalt.

This study, along with others (Bowen and Blackwell, 1975; Hull,
1975) indicates the region has an average geothermal gradient of
about 85°C/km. Because of the reliance on geothermal gradients
in predicting subsurface temperature conditions in this study,
individual profiles of many of the measured geothermal gradients
are shown in Figure 12. Also shown for comparison are lines that
represent geothermal gradients of 70° and 100°C/km. Most gradi-
ents are linear, indicating consistent rock thermal conductivity.
The nonlinear geothermal gradients, such as 19S/46 E -15DC and
17S/45 E -11DC represent water movement in the bore hole or within
the formation. By projecting this regional geothermal gradient to
the depths where the basaltic reservoir rocks are expected to
occur, an estimation of reservoir temperatures can be made. For
example, in the region between Ontario and Nyssa the top of the
Grassy Mountain Basalt is expected to be at a depth of between
1 and 1.2 km. The overlying Chalk Butte Formation has a consistent
lithology of mostly tuffaceous siltstone and claystone with minor
poorly sorted sand and gravel. Because of this consistent lithology,
a geothermal gradient measured in the upper 50 to 150 m can be
expected to remain relatively constant until a differing lithology
or a zone of moving groundwater is reached. By projecting the
85°C/km geothermal gradient to 1 km, the temperature at that depth
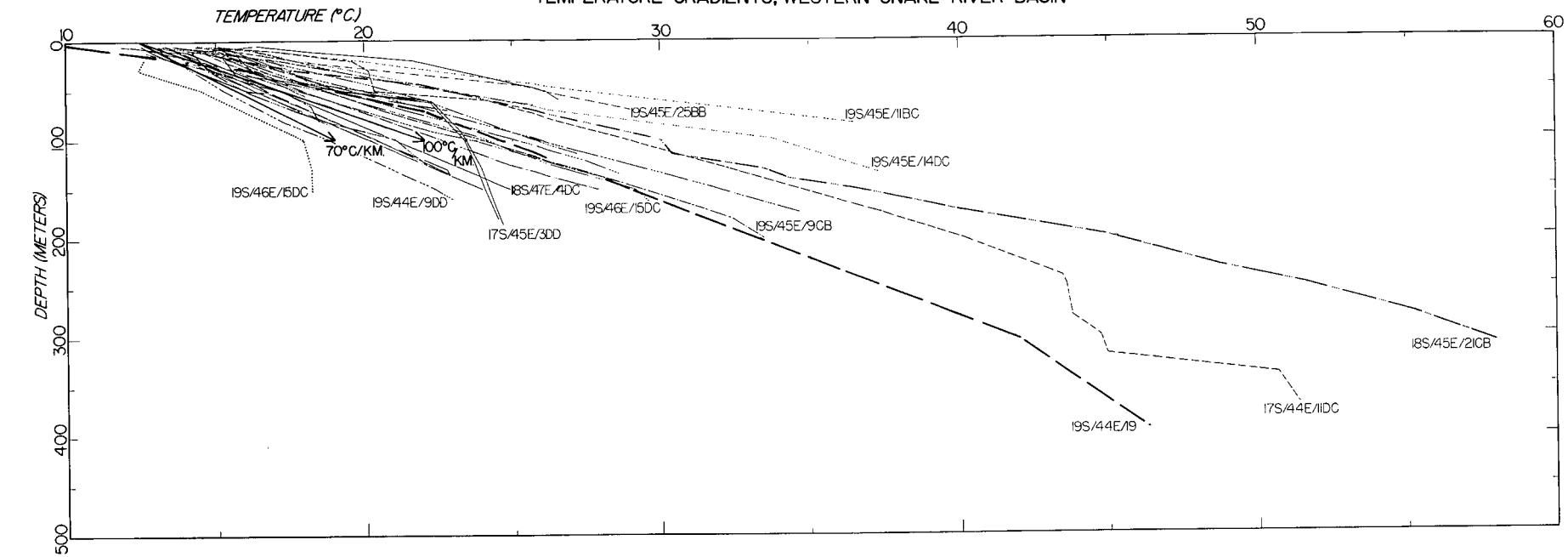
Profiles are designated by location of Township, Range and Section and by 1/4,1/4 section. The alphabetical designation of 1/4 and 1/4,1/4 section follows the USGS Water Resources publication practice. A represents the NE 1/4, B the NW, C the SW and D the SE. Therefore, a location given as 19S/45E/11BC is in Township 19 South, Range 45 East, SW, NW Sec 11. Two profiles, 70°C/km and 100°C/km, are shown to illustrate the slopes represented by these gradients. The highest shown, 19S/45E/11BC, is approximately 250°C/km. This hole is located just south of Vale on the Willow Creek Fault zone. With only a few exceptions, probably caused by circulating water, the profiles tend to be linear. The general decrease in gradient with depth in the deeper holes, 19S/44E/19, and 18S/45E/21CB, is due to the presence of basalts that because of higher thermal conductivity show decreased gradient for a given heat flow. The sharp gradient change in 19S/44E/11DC, 19S/46E/15DC and 17S/45E/30DD is probably due to flows of water within the well bore. The Parma, Idaho well was logged before temperatures stabilized and still shows some of the effects of drilling.

can be assumed to be about 95°C (85° + 10° surface temperature). Deeper wells in the same area drilled to the Owyhee Basalt would expect to penetrate 0.1 to 0.4 km of Grassy Mountain Basalt with a small increase in temperature to the underlying Kern Basin Formation. In the Kern Basin Formation the geothermal gradient will be only slightly lower because of the slightly higher conductivity of the more compact rocks, so a geothermal gradient of 70°C/km is estimated. Therefore, by drilling 1 km below the Grassy Mountain Basalt, temperatures of about 165°C (95° + 70°) can be expected.

If the anticipated use of the geothermal fluid in the range of 90° to 100°C from the Grassy Mountain Basalt and 140° to 165°C from the Owyhee Basalt can justify the costs necessary to drill to the 1- or 2-km depths, there is reasonable assurance that the resource can be located anywhere in the study area. Drilling costs are discussed in a later part of this report.

The Western Snake River Basin is divided into five subareas for the purpose of discussion in this report (Figure 13). The subarea maps indicate the locations of the known thermal springs and wells, the wells that were used to determine the geothermal gradients, and zones where fault-related geothermal waters are expected to occur at depths ranging from a few feet to 1 km.

2. Subarea Assessment

   a. Ontario Subarea

Nearly all of the Ontario subarea lies within the bottomlands of the Malheur and Snake Rivers. With the exception of a small block of hill land in the northwest corner, this is all high-use agricultural, industrial or residential land. Ontario is the trading center of the study area, and probably 75 percent of the population is located in the Ontario subarea. Most of the area is covered with recent alluvium from the Malheur and Snake Rivers; underlying the alluvium are siltstones and claystones of the Chalk Butte Formation with a probable thickness of 1 to 1.5 km. Structurally, the rocks dip at low angles, 3 to 4 degrees, toward the east. Studies based on information from oil and gas tests drilled around the region indicate that the Owyhee Basalt underlies the basin at a depth of about 2 km in the area of Ontario. Where well control is available in western Idaho the depth to the Owyhee Basalt appears to be about the same. A major northeast-trending geologic structure, the Malheur River fault (Bowen and Blackwell, 1975), appears to parallel the Malheur River from Vale to Ontario.

A variety of geophysical data, including gravity data by Baldwin and Hill (1960) and Couch (1977), and an audio-magnetotelluric survey by Long, Hoover and Bramsoe (1975), confirm the stratigraphy, thickness and depth of rock units, and the general structural features.

Figure 13.

Sub-area Index Map
of the
Western Snake River Basin

1 Ontario
2 Nyssa
3 Adrian
4 Vale
5 Bully Creek

ONTARIO SUBAREA

LEGEND

Greater than average potential for hot water from 50°C to 100°C at depths of 500 to 1,000 m.

Greater than average potential for hot water from 50°C to 100°C at depths of 100 to 500 m.

Fault inferred from geology.

Fault inferred from geophysical data.

DRILL HOLE WITH GEOTHERMAL GRADIENT

O   Gradient < 70°C/km.

●   Gradient ≥ 70°C ≤ 99°C/km.

⊕   Gradient ≥ 100°C/km.

M   Measured geothermal gradient. Others are projected.

⊕S?   Hot spring or artesian warm water well: (?) not located during this study.

34   Figure 14.

The best evidence that geothermal resources underlie the Ontario subarea is the presence of high geothermal gradients measured around the margins of the area and from the fact that hot water is known to occur in the rocks that surround and underlie the basin.

Measured geothermal gradients from two wells drilled specifically for that purpose, one in sec. 16, T. 17 S., R. 43 E., and the other in Lions Park in Ontario, range from 86° to 115°C/km.

The best potential for locating significant quantities of hot water in this subarea is to drill to the deep basalt aquifers as suggested earlier in the report. At Ontario the depth to the Grassy Mountain Basalt is predicted to be slightly over 1 km with temperatures of about 100°C. The Owyhee Basalt should be found at about 2 km with a temperature of about 160°C. The cross-section (Figure 11) illustrates subsurface geologic conditions in this region.

Waring (1965) reported a 73°C hot spring along the Malheur River three miles west of Ontario. A field check has failed to confirm this occurrence and local residents did not know of it. No other surface indications are known to be present. The only shallow target zone is inferred from measured well gradients and here above-normal temperature may be found; water volume may not be adequate.

b. Nyssa Subarea

This subarea is largely in the flood plain of the Snake River except for the northwest quarter which is rolling sagebrush-covered hills (Figure 15). Like other bottomlands in the region, high-intensity agriculture is the predominate land use and perishable high-value crops such as sugar beets, onions, potatoes, corn and beets predominate. In the foothills dairying and cattle feeding are important industries. A fruit and vegetable cannery and a sugar mill are important processors of local crops and provide year-around employment in the region. The water for irrigation is supplied mainly from surface sources and delivered by ditches and pipelines. As surface water allocations are used up, groundwater is beginning to supply increasing amounts of irrigation water. Outside of the cities, most domestic water is from shallow wells.

Rocks underlying the subarea are fine-grained claystone, siltstone and sandstone of the Chalk Butte Formation. Terrace gravels cover the lower bench areas and fine-grained alluvium the flood plains of the Snake River. The cross-section (Figure 11) illustrates the general geologic environment of the region. Two oil well tests show that the Grassy Mountain Basalt occurs at a depth of about 1 km and the Owyhee Basalt at about 2 km.

NYSSA SUBAREA
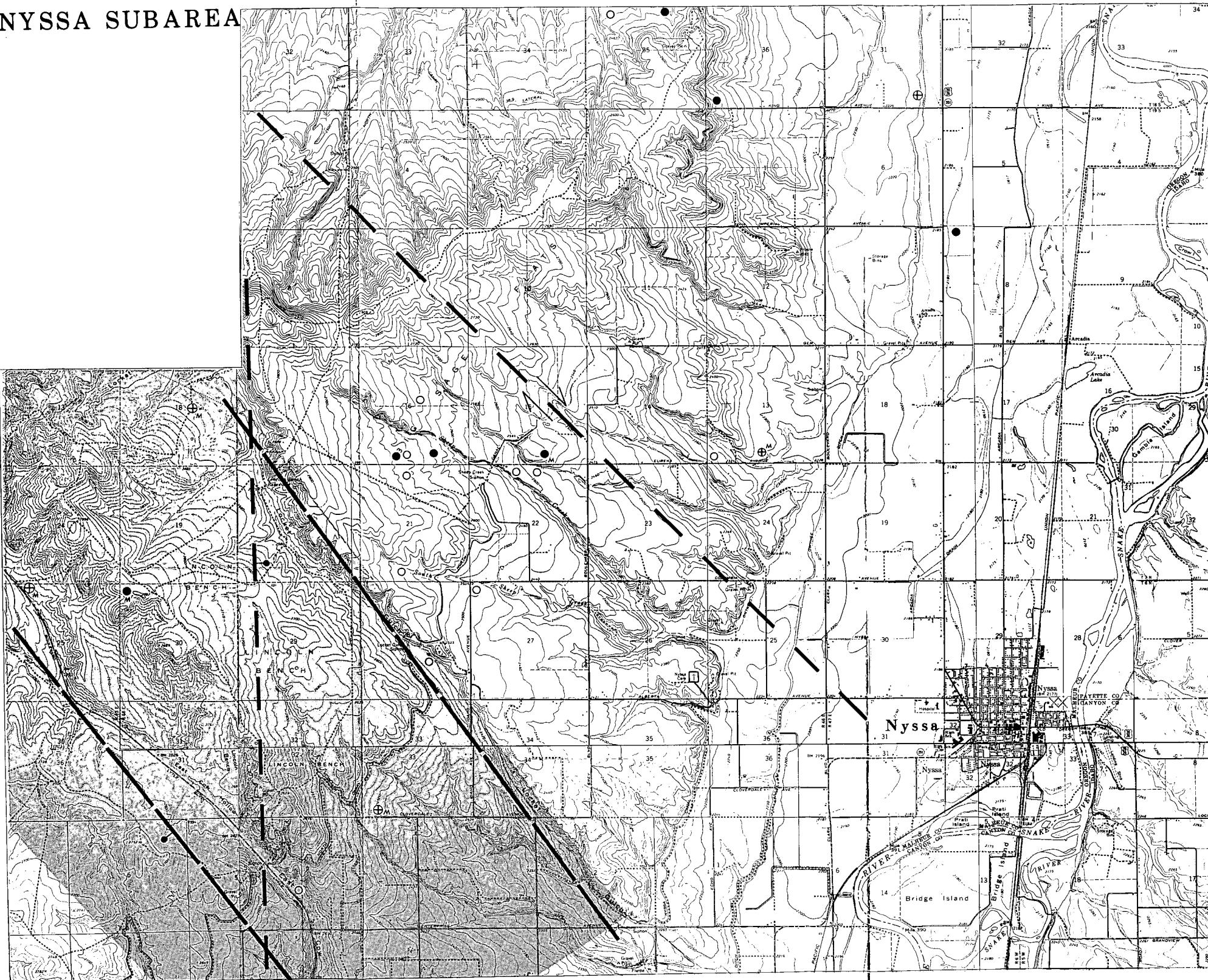
LEGEND

Greater than average potential for hot water from 50°C to 100°C at depths of 500 to 1,000 m.

Greater than average potential for hot water from 50°C to 100°C at depths of 100 to 500 m.

Fault inferred from geology.

Fault inferred from geophysical data.

DRILL HOLE WITH GEOTHERMAL GRADIENT

○ Gradient < 70°C/km.

● Gradient ≥ 70°C ≤ 99°C/km.

⊕ Gradient ≥ 100°C/km.

M Measured geothermal gradient. Others are projected.

Ⓗ$_S$? Hot spring or artesian warm water well: (?) not located during this study.

Geophysical studies by Couch (1977) and a geothermal study by Bowen and Blackwell (1975) show the subsurface structure of the Nyssa subarea to be complex and several north to northwest-trending faults both normal and strike slip have been delineated. Their inferred trends are shown in Figure 15.

There are no geothermal manifestations known in this subarea; however, temperature gradients, both measured and those interpreted from water well logs, show geothermal gradients greater than 100°C at several locations. The most prominent geothermal anomaly is the Cow Hollow geothermal anomaly as discussed by Bowen and Blackwell (1975), which extends into the southwestern edge of this subarea and is shown as a geothermal target zone on Figure 15.

Bowen and Blackwell (1975) have interpreted that this anomaly is caused by hot water or steam moving upward along the Willow Creek fault zone and that drilling to depths of 1 or 2 km should locate high-temperature water or steam. There is also a possibility that high-temperature fluids might be located by drilling near the strike slip fault interpreted by Couch (1977) as some measured gradients and water well data show above-regional gradients along the fault zone. The potential reservoir horizons, the Grassy Mountain Basalt and the Owyhee Basalt are probably nearer the surface in the western part of the subarea so drilling there would not have to be as deep as in the eastern section. In the eastern part of the Nyssa subarea, it is expected that the same deep reservoirs discussed earlier are present, and at depths similar to those at Ontario.

c. Adrian Subarea

This subarea lies along the transition zone between the Snake River Plain and Owyhee Uplands (Figure 16). Along the eastern edge are the flat bottomlands of the Snake River. In the southwest corner the Owyhee River has eroded a canyon several hundred feet deep. After leaving the canyon the river meanders through a flood plain and joins the Snake River about 7 km north of Adrian.

Truck gardening takes place along the bottomlands of the Snake and Owyhee Rivers and the raising of hay, alfalfa and other grain crops in the adjacent foothills. In the upland areas cattle raising and dairying are the main land uses. Most of the population in the subarea is located near the eastern edge in Adrian and along State Highway 201 which leads north to Nyssa and Ontario. Farms are present throughout all of the region except in the higher hills in the southwest corner. Surface water provides most of the irrigation water while shallow wells provide most domestic water.
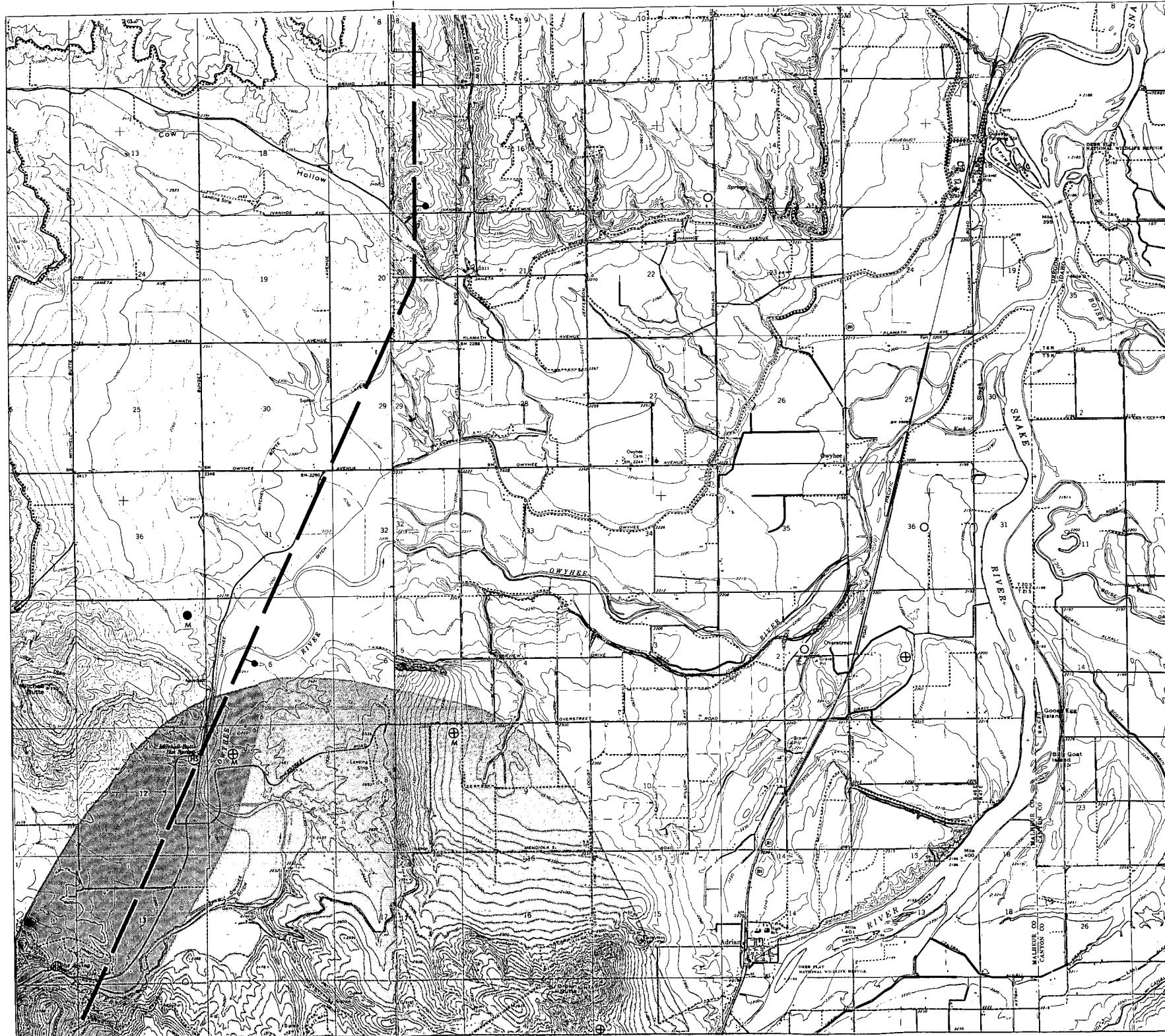
LEGEND

Greater than average potential for
hot water from 50°C to 100°C at depths
of 500 to 1,000 m.

Greater than average potential for
hot water from 50°C to 100°C at depths
of 100 to 500 m.

Fault inferred from geology.

Fault inferred from geophysical data.

DRILL HOLE WITH GEOTHERMAL GRADIENT

O   Gradient < 70°C/km.

●   Gradient ≥ 70°C ≤ 99°C/km.

⊕   Gradient ≥ 100°C/km.

M   Measured geothermal gradient.
     Others are projected.

ⒽⓈ? Hot spring or artesian warm water
     well: (?) not located during this
     study.

38   Figure 16.

Surficial rocks are the fine-grained lacustrine and fluviatile sedimentary rocks of the Chalk Butte Formation. Corcoran (1962) reports that the Chalk Butte rocks here lie directly on the Owyhee Basalt and that the Grassy Mountain Basalt, Kern Basin Formation and the Deer Butte Formation were either eroded away or were not deposited. Corcoran (1962) shows a fault just to the south of the subarea aligned with the Owyhee Canyon. Couch (1977) on geophysical evidence extends this fault northeasterly through the area. Within the Owyhee Canyon at least four hot springs are known to be associated with this fault. Figure 16 shows this faulting and the location of Mitchell Butte Hot Springs and Deer Butte Hot Springs.

The presence of the two hot springs mentioned above along with several more along this same trend in the Owyhee Basalt to the southwest suggests the presence of a major thermal zone. Two measured wells, one near the mouth of the Owyhee Canyon (sec. 7, T. 21 S., R. 46 E.) and the other 2 km to the east (sec. 8, T. 21 S., R. 46 E.), both give gradients of around 120°C/km, and broaden the geothermal target zone. Drilling to depths of 100 to 500 m adjacent to the plotted fault should locate hot water in a temperature range of 50° to 100°C. Between the Owyhee Canyon and Adrian, as shown on Figure 16, drilling to a depth of 500 m to 1 km has a good chance of locating hot water between 50° and 100°C.

d. Vale Subarea

This subarea (Figure 17) is made up mostly of rolling foothills of the Owyhee Uplands that form the western and southern boundary of the Western Snake River Basin. The Malheur River, one of the principal tributaries of the Snake, has cut a valley one to three miles wide and in places two to three benches or terraces have been formed by this erosion. Willow Creek, a tributary to the Malheur River, has also eroded a flat valley two to three miles wide and enters the Malheur Valley at Vale.

Farming activities and all of the homes are located within these two valleys and a few of their small tributaries. The uplands, consisting of rounded hills, are used for grazing. Land ownership patterns follow the topography, with nearly all of the valley land and near foothills under private ownership and the higher hilly land in federal ownership. The long growing season, nearness to processing plants and relatively abundant water had encouraged the development of large-scale farming within the valleys. Most of the water used for irrigation comes from ditches from nearby surface storage reservoirs. With few exceptions groundwater for irrigation is limited to shallow gravel zones near existing streams. Lesser amounts of groundwater for stock watering can sometimes be located in perched lenses at relatively shallow depths in the foothills.

VALE SUBAREA
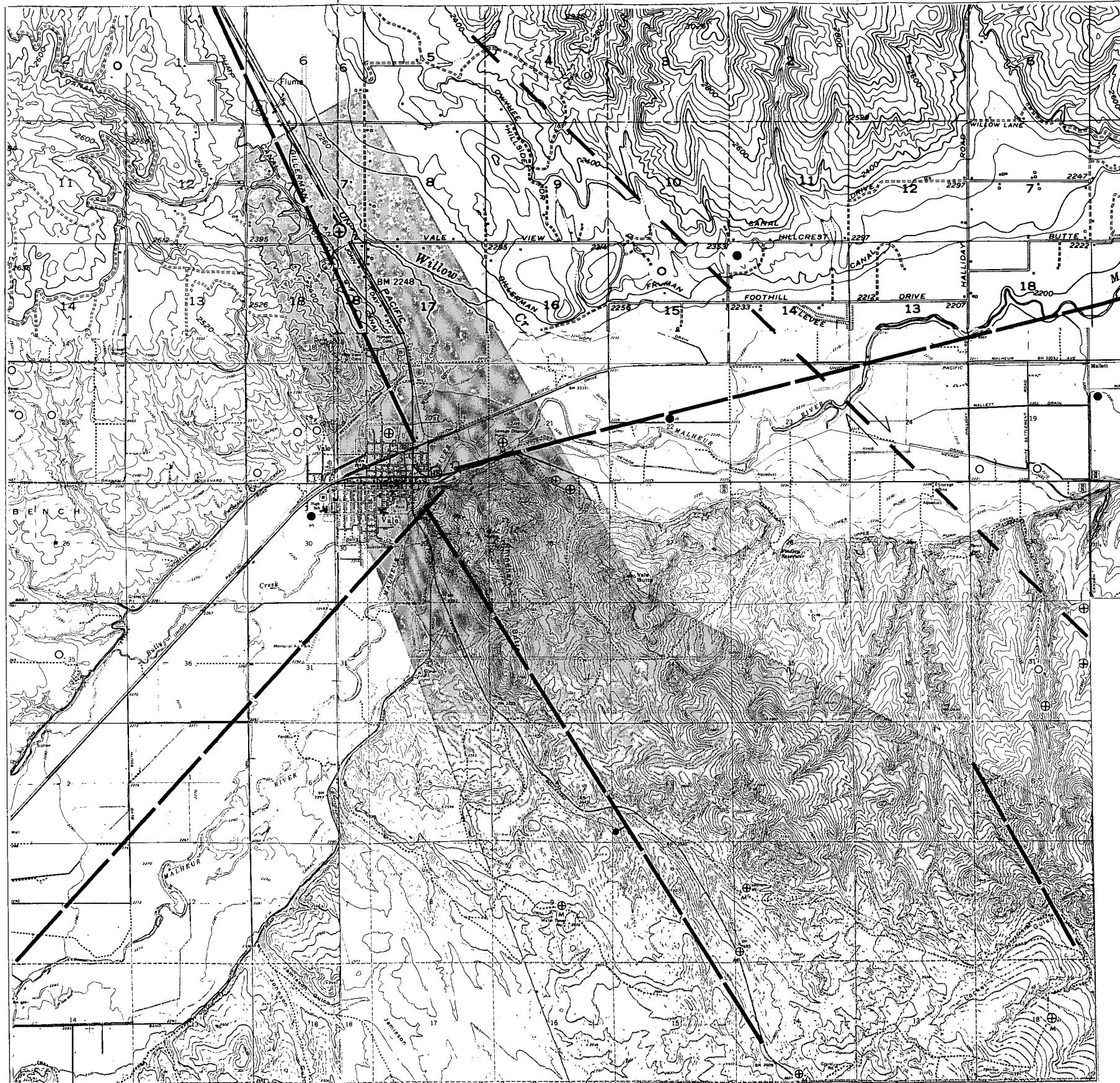
LEGEND

Greater than average potential for
hot water from 50°C to 100°C at depths
of 500 to 1,000 m.

Greater than average potential for
hot water from 50°C to 100°C at depths
of 100 to 500 m.

Fault inferred from geology.

Fault inferred from geophysical data.

DRILL HOLE WITH GEOTHERMAL GRADIENT

O   Gradient < 70°C/km.

●   Gradient ≥ 70°C ≤ 99°C/km.

⊕   Gradient ≥ 100°C/km.

M   Measured geothermal gradient.
     Others are projected.

HS? Hot spring or artesian warm water
     well: (?) not located during this
     study.

Rocks exposed in the foothills are, with the exception of a few alluvial terraces, entirely of the Chalk Butte Formation and consist mainly of siltstone, with lenses of impure volcanic-derived sandstone and conglomerate. Within the valleys fine-grained alluvium predominates, but occasional gravel layers are reported in the well logs.

Along the south side of the Malheur River the rocks generally dip 2 to 4 degrees toward the east, into the Snake River Basin. Several small and a few major faults can be seen and adjacent to them; dips are often quite steep. These fault zones and steeply dipping beds can best be seen at Rhinehart Buttes and Vale Butte south and east of Vale. The Willow Creek fault zone (Bowen and Blackwell, 1975), also called the Vale fault zone by Lawrence (1976), runs diagonally from northwest to southeast through the subarea. The zone is interpreted by Bowen and Black-well (1975) to be a normal fault with the west side down relative to the east. Lawrence (1976) believes it to be a right lateral strike slip fault with the northeast side being displaced toward the southeast. A subparallel fault 5 to 6.5 km northeast of the Willow Creek fault is reported by Couch (1977), based primarily on the interpretation of a gravity survey of the region. Topography and other field evidence supports the presence of this fault. From the gravity study of Couch it appears this fault is down to the east, producing an upraised block or "horst", referred to as the Vale horst in this report. The Malheur River fault, a major northeast-southwest-trending cross fault generally following the course of the Malheur River, has been reported by Bowen and Blackwell (1975).

A part of the area included as the Vale subarea has been designated as a Known Geothermal Resource Area (KGRA) by the U.S. Geological Survey and geothermal leases on the federal lands within the block are offered for sale by competitive bidding. A total of 8,393 acres of the federal leases have been granted at prices ranging between $3 and $16.16 per acre. Geothermal leases have also been negotiated for much of the private land.

Vale Hot Springs, located on the east edge of the city of Vale, has a surface temperature of 97°C and a visible flow of 25 to 50 gallons per minute. Chemical analysis on the hot spring waters shows it has dissolved solids of 882 ppm. The alkali ratio indicates a minimum estimated reservoir temperature of 157°C (Mariner and others, 1975). A shallow well drilled 50 m east of the hot springs was reported to have temperatures of 110°C (Ross Butler, oral communication, 1976). Other shallow wells with temperatures slightly over boiling are located within a half mile of the hot springs, all on the south side of the Malheur River. On the north side of the river near Vale, just to the north of Rhinehart Buttes, shallow wells do not intersect the high-temperature zone located just south of the river, but a 320-m oil test in the SW 1/4 of sec. 21, T. 18 S., R. 45 E. shows there is also a high geothermal gradient of 147°C/km on the north side of the river. Warm-water

wells and the high geothermal gradients along the Willow Creek fault zone, the west boundary of the Vale horst, indicate rising thermal waters to the southeast of Vale. There has been very little drilling on the east edge of the Vale horst, but three water wells in sec. 31, T. 18 S., R. 46 E., have projected geothermal gradients of more than 100°C/km. Northwest of Vale along Willow Creek a few scattered wells with geothermal gradients in the range of 90° to 110°C/km may also indicate rising thermal waters.

Geothermal waters ranging from near to slightly above boiling in temperature can be expected in shallow wells (100 to 300 m) along the south and east side of the Malheur River extending possibly 1 to 3 km from Vale. North of the Malheur River and north of Highway 26 the geothermal gradient of 147°C/km in sec. 21, T. 18 S., R. 45 E. and 122°C/km in sec. 20, T. 18 S., R. 45 E. indicate a geothermal reservoir, but deeper than that south of the river.

Along Lytle Boulevard, southeast of Vale, a zone of high heat flow, the Cow Hollow anomaly, was reported by Bowen and Blackwell (1975). From their work and from the structural picture outlined by the geophysical studies of Couch (1977), it appears that the Grassy Mountain Basalt may be at depths as shallow as 400 to 500 m along the Vale horst. The high geothermal gradient along Lytle Boulevard indicates that water near boiling in temperature could be found in the Grassy Mountain Basalt at those depths. In the Owyhee Basalt at depths of 1500 to 2000 m temperatures could be in the range of 140° to 165°C.

A slightly more speculative hot-water zone is marked to the northwest of Vale, along the Willow Creek fault zone because of the presence of the scattered water wells indicating geothermal gradients of 90° to 110°C/km.

e. Bully Creek Subarea

This subarea (Figure 18) is located in the foothills of the Owyhee Uplands; the Malheur River has excavated a flat valley about 3 km wide through the middle of the area and Bully Creek, following a valley about 1-1/2 km wide, flows in from the northwest. Along the north side of the Malheur River is a broad gravel covered bench with Bully Creek Valley dividing it into what is known as East Bench and West Bench. Farming takes place in the valley and in the Bench area and grazing in the rest of the hills. Most of the irrigation water is provided by surface canals that use water from the Malheur River and from Bully Creek Reservoir. A few wells are drilled into the Malheur River and Bully Creek floodplains to provide some irrigation water. In the East and West Bench areas there is sufficient water for domestic wells in the gravel terraces. Away from the valleys a few stock wells produce small amounts of water from perched zones.

BULLY CREEK SUBAREA
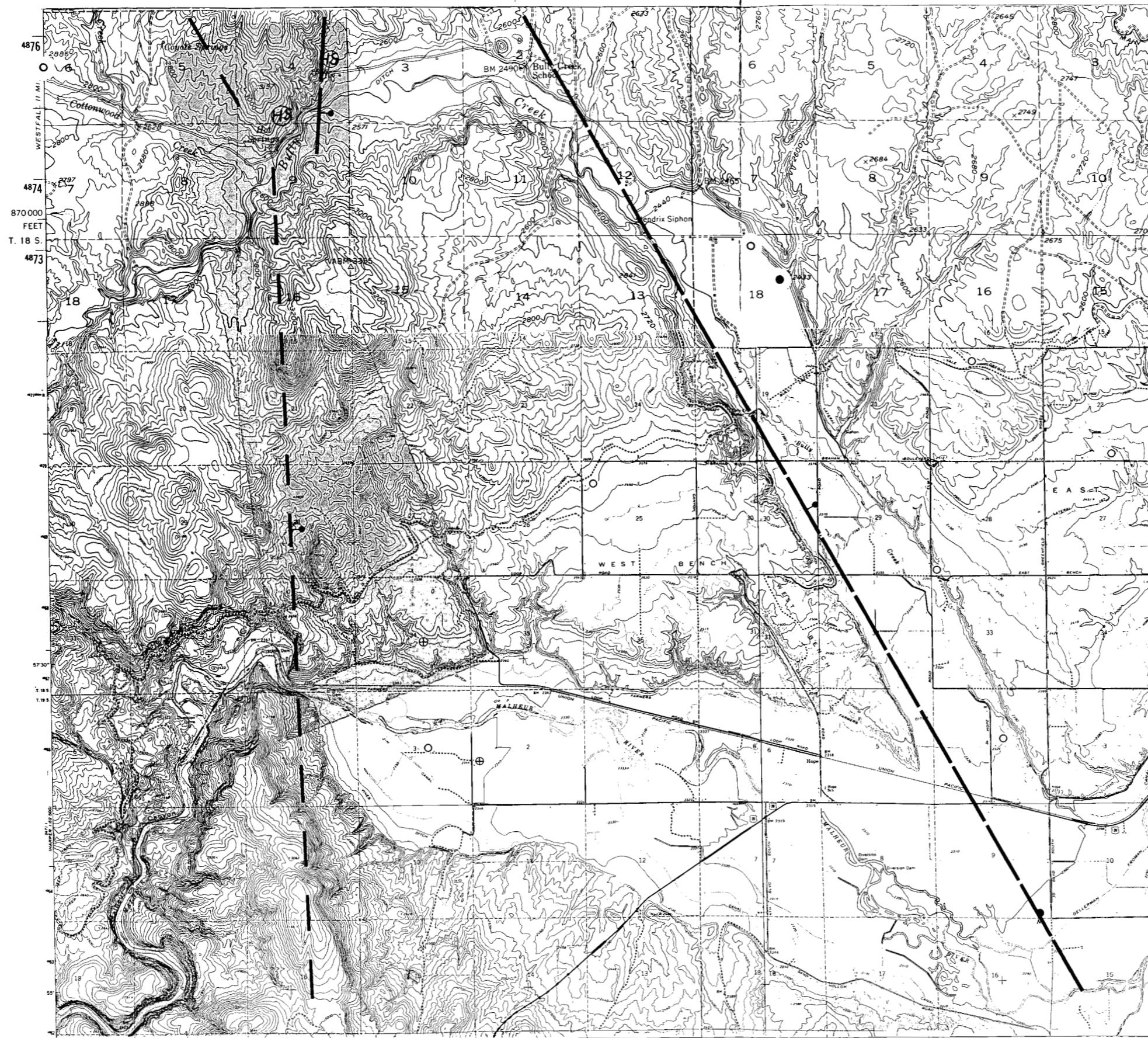
LEGEND

Greater than average potential for
hot water from 50°C to 100°C at depths
of 500 to 1,000 m.

Greater than average potential for
hot water from 50°C to 100°C at depths
of 100 to 500 m.

Fault inferred from geology.

Fault inferred from geophysical data.

DRILL HOLE WITH GEOTHERMAL GRADIENT

Gradient < 70°C/km.

Gradient ≥ 70°C ≤ 99°C/km.

Gradient ≥ 100°C/km.

Measured geothermal gradient.
Others are projected.

Hot spring or artesian warm water
well: (?) not located during this
study.

43   Figure 18.

Land ownership patterns follow traditional eastern Oregon usage with the river valleys and the bench lands near the main streams in private ownership. Large farms make up most of the flat valleys while smaller farms and dairies are in the bench areas and lower foothills. The uplands are mainly in federal ownership and are largely used for grazing.

Surficial rocks are largely unconsolidated to semiconsolidated sediments of the Chalk Butte Formation. Near the northwest corner of the area are basalts reported to be of late Miocene age by Walker (1977), correlating with the Owyhee and the Columbia River Basalts. Just south of the subarea, Grassy Mountain Basalt is exposed in Double Mountain. Quaternary terrace gravels cover both the East and West Bench.

This subarea is on the western edge of the Western Snake River Basin; the older Miocene basalts occur immediately to the west and the younger basin sediments dip and thicken toward the east. Oil tests and some of the water wells drilled in the area intersect basalts at relatively shallow depths. Two prominent fault zones intersect in the area; one, a northwest-southeast zone follows the course of Bully Creek; another following a northeast-southwest trend aligns with Sand Hollow and the Malheur River. The structural interpretation by Bowen and Blackwell (1975) indicates the presence of a graben, or down-dropped block between the Bully Creek and Willow Creek fault zones. Couch (1977), from the interpretation of geophysical data, also reports a graben in the area between Vale and Bully Creek, but his data indicates the graben to be west of the Bowen and Blackwell projection.

Geothermal manifestations in the subarea are Neal (Bully Creek) Hot Springs in the NW 1/4 of sec. 9, T. 18 S., R. 43 E., and an unnamed warm spring about one mile to the northeast of Neal Hot Springs. Neal Hot Springs has a maximum surface temperature of 87°C and water analyses indicate that minimum subsurface reservoir temperatures are 173° to 181°C (Mariner and others, 1974). Two water wells on the east edge of the subarea show above-normal gradients. The Nelson well in sec. 34, T. 18 S., R. 43 E. has a reported water temperature of 21°C at a depth of 58 m, which indicates a geothermal gradient of 157°C/km. The BLM Vines Hill well in sec. 22, T. 19 S., R. 43 E., has a water temperature of 31°C from a 219-m depth, indicating a gradient of 94°C/km.

A prospective drilling target is shown on Figure 18 along the western edge of the subarea. The Owyhee Basalt appears very close to the surface, probably covered only by a thin layer (0 to 1000 m) of Chalk Butte Formation. The high temperatures indicated by the geochemical analysis (Mariner, 1974) for Neal Hot Springs may give an indication of reservoir conditions. A fault zone postulated by Couch (1977) from geophysical data appears to be the zone of leakage of the geothermal fluids. From the present indications further drilling along this zone appears to be warranted.

D. Reservoir Management

To conserve and to achieve the greatest beneficial use of geothermal resources and to protect the groundwater from damage due to excessive reservoir drawdown or improper disposal of the spent geothermal fluids, a program of reservoir management should be established at the time of initial reservoir development. Calculations indicate that large quantities of energy underlie the study areas (White and Williams, 1975); however, to transfer this energy to the surface requires large flows of water.

It is possible that the geothermal reservoirs in the study areas contain enough water to maintain production for as long as they are needed or that they will be recharged by natural means. Initial flow testing can only indicate the rate at which the well can be produced, not the life of the well or the ultimate reservoir capacity, nor if recharge exists. To determine if a reservoir has sufficient capacity to fulfill the needs of a major industrial or institutional user could require many years of production and long-term testing and monitoring. This uncertainty of availability of water, and of its possible effects on the shallower groundwater in the areas can be resolved if the spent geothermal fluid is returned to the production reservoir. Additionally, this method of disposal eliminates contamination of surface waters that might result if surface disposal methods are used.

Any significant use of geothermal energy in the Western Snake River Basin or an increase in its use in the Klamath Basin will require large flows of water. For example, if a modest-sized industrial plant presently using natural gas in amounts of 10,000 therms a month in a process that requires maximum temperatures near 150°C switches to geothermal energy, it will require a pass-through of water amounting to 23 gpm or approximately 3 acre-feet per month or 36 acre-feet a year. The present pass-through at Oregon Institute of Technology where a 500,000 square foot campus is heated with geothermal water is 200 to 250 acre-feet per year. Therefore, it can be seen that a significant increase in the usage of geothermal heating could increase demand for water by several thousand acre-feet per year in each region. The disposal of this flow into surface drainages could present both disposal and environmental problems and an increase in the demand on the groundwater of that magnitude might cause objectional reservoir drawdown. With proper reservoir management the potential problems of handling these large flows can be taken care of by returning the geothermal fluid to the reservoir via return wells.

Fortunately, in Klamath Falls experience in returning large flows of geothermal water has been developed over the last 15 years by the Klamath Falls School District. Three schools use geothermal heating systems in which the hot water is circulated through heat exchangers in the buildings then returned to the reservoir via return wells. These three systems which have been in operation since 1962, 1965 and 1967 have returned an average of 1,000 acre-feet of water a year into the reservoirs with no apparent deleterious effects.

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In other geothermal fields in both the United States and abroad routine methods of return of the fluids into the reservoirs have been practiced, for several years in some cases, and in others long-term production tests have shown this method of disposal to be satisfactory. Reports on several of these return systems have been presented in the literature and are summarized here.

In Rotorua, New Zealand, Burrows (1970) and Shannon (1975), have reported on the systems developed in that area. In Rotorua the geothermal waters are generally quite high in temperature, 105° to 170°C, and have wellhead pressures ranging up to 150 psig. Burrows (1970) reports that there are over 700 production wells within the city and that a return well, termed a "soak bore" is normally drilled for each production well and that it is routine practice to drill the "soak bore" on the same lot as the production well. Many of these "soak bores" are shallow, hand-dug pits, lined with rock and covered with wooden or concrete doors that allow the water to soak into the permeable pumiceous soil under the city. Others are deep wells that return the spent fluids to the reservoir, most often below the production zone. In Rotorua a position of Inspector of Geothermal Works has been established to encourage and oversee the orderly and efficient development of the geothermal resources. Additionally the city requires that all geothermal wastewaters be properly returned to the ground so it has become standard practice to drill the production and the disposal wells at the same time and on the same property. The geothermal waters in Rotorua normally contain 1,800 to 2,000 ppm dissolved solids with 180 to 200 ppm silica. The routine return of geothermal fluids into the ground has been practiced in Rotorua for many years and both authors report it has no detrimental effects in the region.

In Otake, Japan, a high-temperature geothermal field in which the fluid is used for the production of electric power, return of the water began in 1970. Reports by Yanagase, Suginohara, and Yangase (1970) and Kubota and Aosaki (1975) detail the experience in that field. In the Otake case several production wells produce an average of 2,300 gallons per minute, or over a year's time nearly 3,700 acre-feet of water. Since 1972 this has all been returned into the production reservoir via three return wells. Prior to 1970 the wastewater from Otake field was piped to a hydroelectric reservoir 4.5 km from the field for disposal. This method started causing problems immediately as the large amount of silica in the waters, in this case 400 to 600 ppm with 3,000 to 4,000 ppm total dissolved solids, tended to precipitate and plug the pipeline making it necessary to frequently clean the pipeline by mechanical scrapers. Because of the continual problem in maintaining the pipelines it was decided to experiment with returning the fluid directly into the reservoir. After successfully running a two-year test from 1970 to 1972 in which a part of the fluids was returned to an unused well in the center of the field, two disposal wells were drilled and the pipeline disposal system abandoned. Kubota and Aosaki (1975) report that with the use of the pipeline disposal system there was a steady decline in the production of the field with power output declining from 11 to 8.7 MW from 1967 to 1971.

With the beginning of fluid return to the reservoir the decline stopped in 1971 and production began to increase, rising to 10 MW by 1973. At the time of the report (1975), production had held level since 1973 at 10 MW. The decline was caused by natural recharge being unable to supply the water necessary to maintain constant production; return of the water to the reservoir brought in sufficient amounts to recover most of the lost production.

Several other geothermal return systems are described in the literature including The Geysers by Chasteen (1975), the Imperial Valley by Chasteen (1975) and by Mathias (1975), Ahuachapan, El Salvador by Siqvaldson and Cuellar (1970 and Einarsson, Vides and Cuellar (1975). A more detailed review of these systems is presented in the appendix.

Initial planning of a geothermal development should involve, after dis- covery of the resource, the drilling of sufficient return wells to allow for the disposal of all the excess geothermal fluid. Theoretical studies to date indicate that returning the spent fluid to below the production zone would allow it to regain its original heat (Bodvarsson, 1972). In practice at Klamath Falls, The Geysers, and at Otake, return wells have been located both at field margins and within the center of the field, and apparently at random depths into the reservoir, with no detrimental effect. It appears to be important to avoid direct short-circuiting of the returned water into production flow. A program of production and return testing levels that give minimum interference could be worked out.

In summary, research of the geothermal literature shows that nearly all geothermal return systems have been successful, in some cases increasing production rates. The most common problem has been the precipitation of excess silica when the geothermal waters have been allowed to cool. At Klamath Falls and in the Snake River Basin, analyses show silica to be low enough so it should not be a problem. Various problems with the in- jection systems arose in several cases, but through study and engineering, successful systems were developed in nearly all cases. The example of the three return systems utilized by the Klamath Falls School District is probably typical of conditions and results that can be expected from return systems for future Klamath Basin geothermal wells, and for those in the Western Snake River Basin.

E. Drilling and Transmission Costs

Drilling costs vary widely dependent largely on three factors: 1) drill rig availability; 2) depth of hole; and 3) types of rocks encountered. Under normal conditions there are many contract water well drillers with equipment capable of drilling 6-inch to 12-inch holes to depths of 1,500 to 2,000 feet. Very few drillers in the Western Snake River Basin are capable of drilling to depths of 2,000 to 3,900 feet, but equipment may be brought in from central Idaho or western Oregon where drillers have greater capability. For drilling to depths greater than 3,900 feet, larger oil field drill rigs will have to be brought in from out-of-state, probably Utah, Montana, Wyoming or California.

Closely related to drill rig availability is the number of holes to be drilled on any project. If only one hole is drilled all mobilization and demobilization cost must be charged against that one hole, while on a multi-well program these charges can be spread over several wells. Costs might also be brought down by drilling "slim hole" exploration holes. These holes are generally six inches or less in diameter and are capable of locating a reservoir, but would probably not be satisfactory for production testing nor for a production well.

1. Western Snake River Basin

Drilling costs are estimated for the three ranges of depths: to 1,300 feet; 1,300 to 3,900 feet; and 3,900 to 8,200 feet based on conversations with drillers and from experience in other regions.

Exploration holes cased from 1/3 to 1/2 the total depth:

to 1,300 feet	$ 5 to $15/ft
1,300 to 3,900 feet	$14 to $31/ft
3,900 to 8,200 feet	$20 to $50/ft

Production wells, cased, but not including pumps:

to 1,300 feet	$11 to $31/ft
1,300 to 3,900 feet	$21 to $50/ft
3,900 to 8,300 feet	$31 to $61/ft

The above costs are relatively low in comparison to drilling costs in other parts of the state. This reflects the fact that there have been many oil and gas exploration tests drilled in or near the study area. Newton and Corcoran, 1963, report that a total of 44 exploration tests were drilled in the Western Snake River Basin from 1910 to 1961. These test wells have shown that within the study area the dominantly sedimentary rocks make drilling relatively simple. In other parts of the state where geothermal resources could be expected such as the Klamath Basin or the Cascade Mountains, most of the rocks are volcanic. This in general makes more difficult drilling conditions, especially if the volcanics are highly fractured.

Using the above figures, and considering the drilling conditions in the Western Snake River Basin, the following drilling cost scenarios are estimated:

1,300-foot production test north of Vale

Well program: 10" to 160', setting 8" casing, 6" casing to 1,300 feet

Mobilization and demobilization	$ 2,000
Drilling @ $6/ft	8,000
Casing @ $6/ft	8,000
	$ 18,000
Contingencies @ 30%	5,400
TOTAL	$ 23,400 ≈ $20/ft

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3,900-foot production test, Ontario

Well program: 10" to 160', setting 8" casing, 6" casing to total depth

Mobilization and demobilization	$ 10,000
Drilling @ $12/ft	48,000
Casing @ $8/ft	30,000
	$ 88,000
Contingencies @ 30%	26,400
TOTAL	$114,400 $\approx$ $30/ft

8,200-foot production test, Ontario

Well program: 16" to 160', setting 12" casing, 8" casing to 3,300 feet, 6" casing to 8,200 feet

Mobilization and demobilization	$100,000
Drilling @ $31/ft	250,000
Casing @ $11/ft	87,500
	$437,500
Contingencies @ 30%	131,250
TOTAL	$568,750 $\approx$ $70/ft

2. Drilling Costs--Klamath Basin

Well drilling costs in the Klamath Basin by cable or rotary rigs up to 3,000 feet is as follows:

> $1 per inch of diameter per foot of depth in "soft" rock and $2.50 per inch of diameter per foot of depth in "hard" rock up to 500 feet in depth. For every additional 500 feet increment add $1 per foot of depth.

> Casing cost can be estimated at $1 per inch of diameter per foot of depth. Full-depth casing is assumed for all wells.

Using the above costs which include mobilization and demobilization and considering drilling conditions in the Klamath Basin (i.e., one-third of drilling in "hard" rock), the following drilling cost scenarios are developed:

Well program: 12" diameter hole with 10" casing to 500 feet, 10"
hole with 8" casing to 2,000 feet, and 8" hole with
6" casing to 3,000 feet

Average Well Costs

Depth (feet)	100	500	1,000	2,000	3,000
Drilling costs ($)	1,800	9,000	17,000	34,500	51,000
Casing cost ($)	1,000	5,000	9,000	17,000	23,000
Total cost ($)	2,800	14,000	26,000	51,500	74,000

Range of Costs

	100	500	1,000	2,000	3,000
All "soft" rock ($)	2,200	11,000	20,500	41,000	59,500
All "hard" rock ($)	4,000	20,000	37,000	72,500	103,000

Figure 20 illustrates the capital costs of drilling and casing a
well in the Klamath Basin.
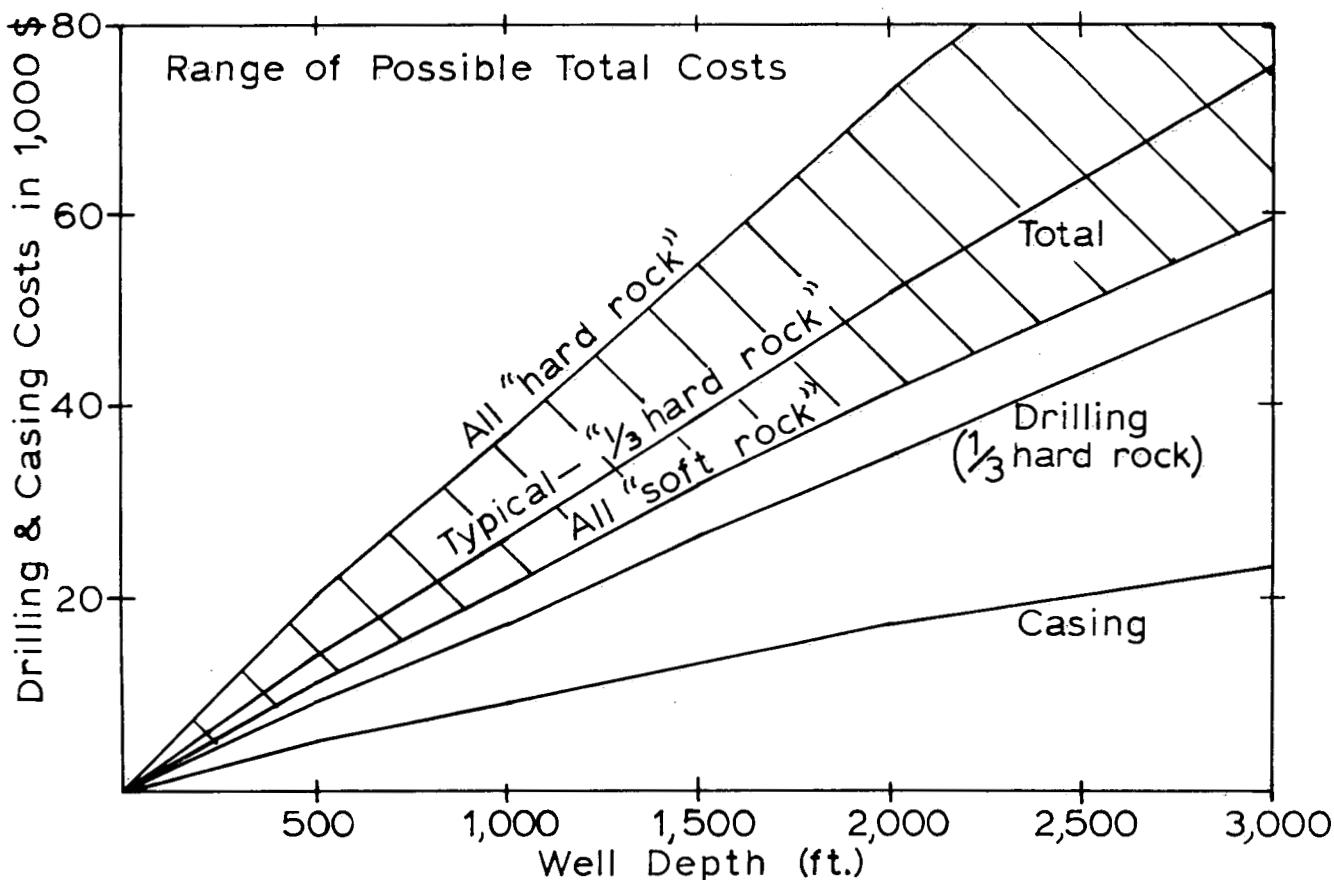
Figure 19. Drilling and casing capital costs

3. Transmission Costs

Transmission costs will vary depending upon the quantity of fluid required and the size of pipe. Insulated asbestos cement pipe buried to a depth of three feet in soil with K = 12 Btu/hr - ft^2-($°F$/in) is assumed for the transmission line for fluids with a temperature less than 210°F. Sample costs are as follows:

Pipe diameter (inches)	Flow Rates Range (gpm)	Flow Rates Head loss (@ 0.01 ft/ft)	Insulated pipe cost ($/ft)	Trenching costs ($/ft)	Fitting cost ($/ft)*	Total cost ($/ft)
3	25-225	(75)	8	0.75	2.00	10.75
4	50-400	(150)	10	0.75	2.50	13.25
6	400-675	(375)	12	1.00	3.00	16.00
8	450-1500	(825)	18	1.00	4.50	23.50
10	600-2500	(1500)	23	1.25	5.75	30.00
14	825-5000	(3500)	40	1.50	10.00	51.50

*Estimated @ 25 percent of pipe cost.

Figure 21 illustrates the capital costs of a buried insulated asbestos cement transmission line.
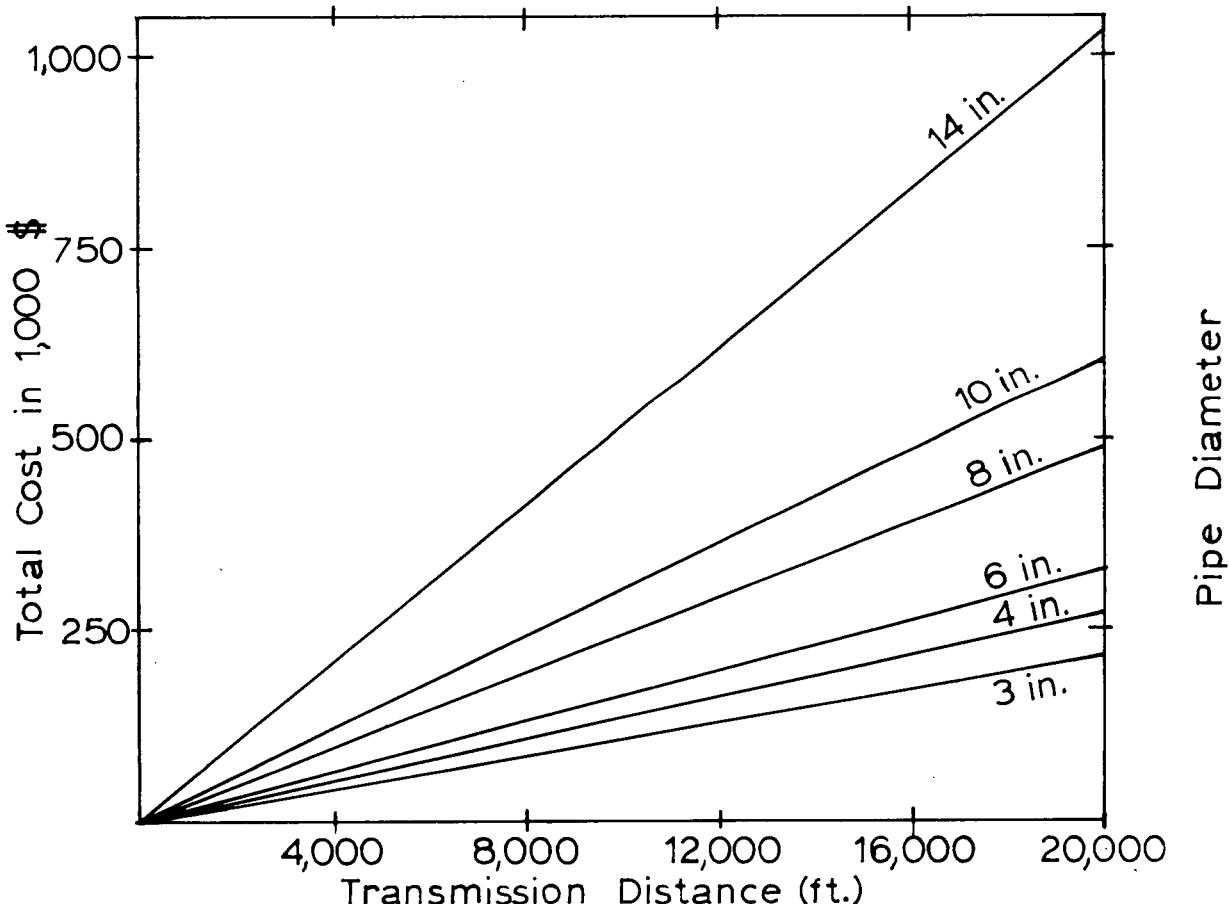
Figure 20. Insulated pipe costs
(asbestos cement pipe with urethane insulation)

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Geothermal fluids with temperatures greater than 210°F are transmitted to steel pipe, with bellows type expansion joints, insulated with a fiberglass wrap and housed in an enclosed concrete duct. A system of this type with an 8-inch insulated supply and bare return will cost approximately $80/ft.

F. Institutional Factors

Those environmental and regulatory factors directly related to the geo-thermal resource assessment will be addressed.

1. Environmental

a. Drilling

The areas under consideration in the two counties where wells may be drilled will be remote from urban and suburban populations with the exception of the Ore-Ida Foods, Inc. plant in Ontario, Oregon.

1) Klamath Basin

Rotary and cable tool drilling equipment should be able to complete wells in this basin. The terrain is flat so drilling wastes should not run off the property. Minimal noise, visual and social factors would be involved. Disturbances of biological communities should not be involved at the drillsite nor with wastes from the site. Return wells are recommended as the most environmentally feasible method of geothermal effluent disposal.

2) Snake River Basin

Oil well drilling equipment will most likely be utilized to drill wells up to 2 km deep. Noise controls would be required on all deep wells as free steam would most likely occur during and after drilling operations. The terrain at all sites would be flat so drilling wastes should not run off the property. Arrangements will need to be made with local authorities for drilling waste disposal. Some noise and social factors may be involved at the Ore-Ida site. Noise factors may be evident at the Amalgamated Sugar Company site. Disturbance of biological communities should not be involved at the drill sites nor with wastes from the site. Return wells are recommended as the most environmentally feasible method of geothermal effluent disposal for both sites.

b. Disposal of Excess Water

As more and more hot water is utilized in the Klamath Basin both for space heating or industrial applications (including antici-pated agribusiness), there will be greater volumes of excess water that still contains some heat that will require disposal.

Hot waters in the Klamath Basin have relatively high concentrations of sodium and sulfate (Figure 19), with total dissolved solids from 750 to 900 mg/l (ppm). Hydrogen sulfide gas is detectable in most of them and the waters are clear and soft to moderately soft and slightly basic (pH 7.5 to 8.5). Iron, manganese, flourine, boron, or other toxic elements are within the range or below the standards
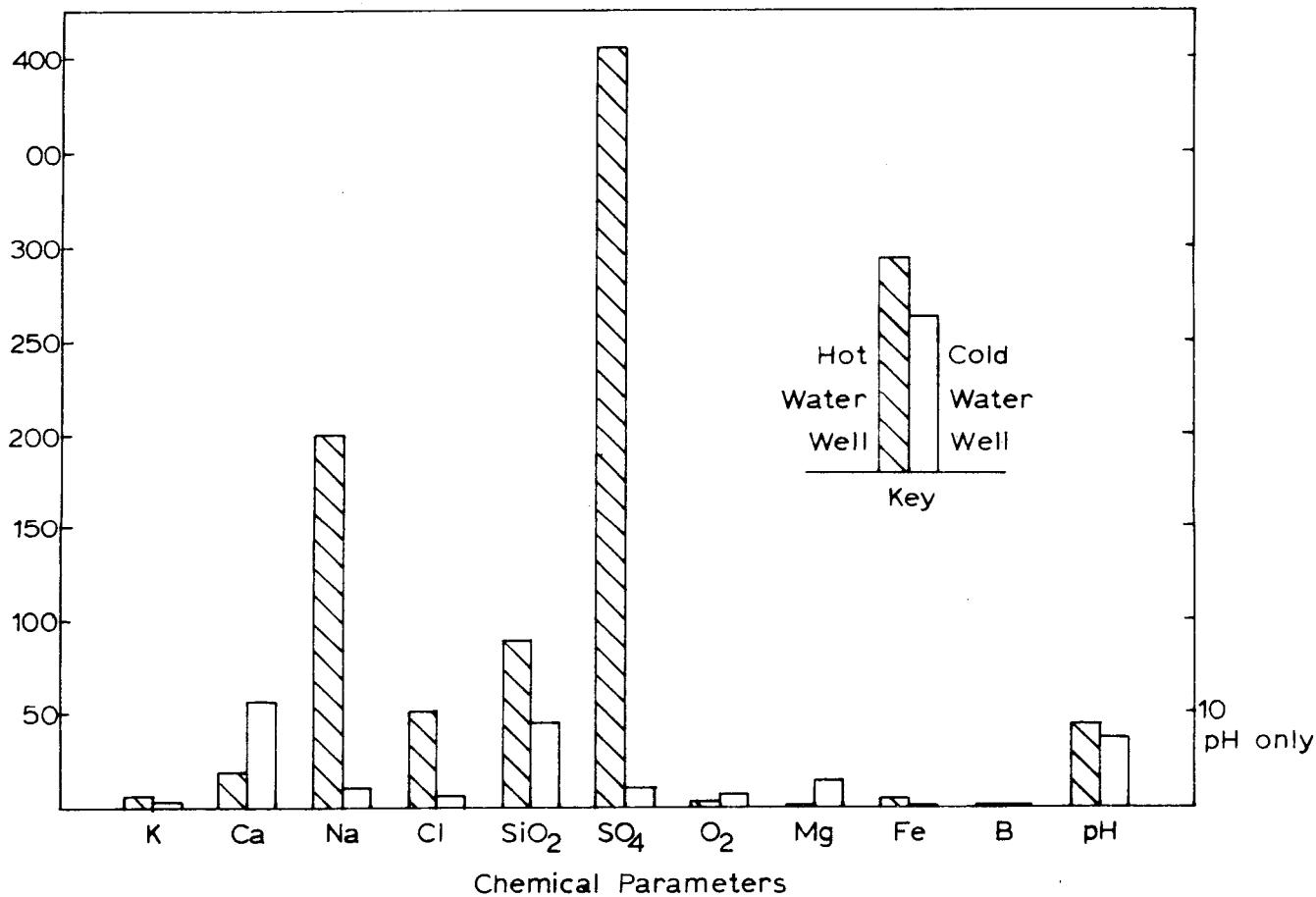
Figure 21. Klamath Basin
Chemical composition of cold and heated groundwater.

for drinking water recommended by the U.S. Public Health Service. Even though the total dissolved solids is above the 500 ppm recommended for drinking water (Table I), the only radical that exceeds the standard is sulfate and that by only 100 to 200 ppm. It is very possible that the hot-water quality would be acceptable to many users even for drinking.

TABLE I

U. S. Public Health Service
Drinking Water Standards, 1962

	Recommended limit (ppm)	Maximum Allowable (ppm)
Alkyl benzene sulfonate (ABS)	0.5	--
Arsenic	.01	0.05
Chloride	250	--
Copper	1.0	--
Flouride	.8-1.7	1.6-3.4
Iron	.3	--
Lead	--	.05
Manganese	.05	--
Nitrate	45	--
Sulfate	250	--
Dissolved solids	500	--

Excessive or abnormal heat added to surface water is sometimes considered to be a pollutant by restricting aquatic plants and animals or depleting oxygen.

It is very probable that in many cases in the Klamath Basin excess waters with some heat remaining could be disposed of at the surface in still ponds, spray ponds, or cooling towers with no adverse effect on the local surface waters.

Where surface disposal is not predictable, injection or return to the ground water reservoir may be the ultimate solution. This method of disposal has been used at Klamath Falls for a number of years and a history at three installations has been satisfactory with no apparent side effects.

c. Other Factors

1) Klamath Basin

Some odor effluent could exist from an onion dehydrating plant. The location of the dehydrator would govern whether the site would be close enough to human habitation where the problem could become offensive.

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2) Snake River Basin

No other environmental factors are evident at this planning stage.

2. Regulatory

   a. Federal

Regulatory measures which may restrict acceleration of low- to moderate-temperature geothermal resource utilization are in two different areas of federal control. The first involves the general definition of geothermal resources which are identified with "all coal and other minerals." The second involves the regulation of geothermal fluid disposal,which is controlled by two public laws. Public Law (P.L.) 92-500, the Clean Water Act, regulates the surface disposal of fluids and P.L. 93-523, the Safe Drinking Water Act, regulates the methods of reinjection of fluids into groundwater reservoirs.

   1) Property owner rights to geothermal resources are not definite as a large quantity of western United States lands were obtained under the 1916 Stock-Raising Homestead Act which did not include mineral rights with the land. The federal definition of geothermal resources includes them as a mineral so the resource is excluded from the rights of the landowner. The federal definition was upheld by a January 31, 1977 decision of the Ninth District Court of Appeals in the case of United States vs. Union Oil Company No. 74-1574. Any entity intending to utilize geothermal resources should initially establish that mineral rights are included with the land at the prospective drill site.

   Oregon congressmen in Washington, D.C. are trying to have the federal definition of geothermal resources restricted to those resources with temperatures greater than 121°C (250°F), and/or those taken from wells greater than 2,000 feet in depth, and to remove the "mineral" classification. This definition would correspond to Oregon's definition and geoheated water with temperatures less than 121°C and/or from shallower wells could be considered hot groundwater.

   2) Surface disposal of geothermal fluid effluents is regulated by the Environmental Protection Agency (EPA) under rules stated in the Clean Water Act of 1972, P.L. 92-500. The basic objective of the Act "is to restore and maintain the chemical, physical, and biological integrity of the nation's waters." Effluent limitations are defined for each source and an approved National Pollution Discharge Elimination System (NPDES) permit is issued to the individual permittee. Limitations could include temperature, chemical, and physical parameters. The NPDES permits for surface effluent discharges in Oregon are issued by the Oregon Department of Environmental Quality (DEQ) and entities considering

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a surface discharge of geothermal fluids should contact this agency. The DEQ office for central and eastern Oregon is located at Bend, Oregon.

Subsurface disposal of geothermal fluid is regulated by the EPA under rules stated in the Safe Drinking Water Act, P.L. 93-523, Section C. This law enters into reinjection plans for this project because of the relative purity of the geothermal fluids in the Klamath and Snake River Basins. The federal definition of drinking water includes those waters with less than 10,000 parts per million (ppm) of total dissolved solids (tds). Geothermally heated waters in both the basins of this study have tds of less than 1,000 ppm. Therefore, under this definition, the geothermally heated waters considered in this study are classified as drinking water. The need for reinjection exists where large quantities of heat energy need to be extracted from the resource and the geothermally heated fluid needs to be raised to the surface where heat extraction is most efficient. Wellhead heat extraction is necessary in most agribusiness industries considered in this study. The regulations related to reinjection in the Act are currently under revision but it is not known what, if any, modifications will be made for the final regulations. Considerable delays are expected in the development of geothermal resources if the regulations stand without modification. All inquiries relative to reinjection of geothermal effluents should be addressed to the DEQ and the Oregon Water Resources Department until a directive is issued by EPA.

The Resources Conservation and Recovery Act replaced and expanded regulations formerly contained in the Solid Waste Disposal Act. The new act is administered by EPA and contains rules related to liquid and contained gaseous wastes. This act and the Toxic Substance Control Act contain certain rules for geothermal waste disposal and may need to be addressed if gaseous wastes are present at the well site.

b. State

Regulatory measures at the state of Oregon level which may restrict development of low to moderate geothermal resources are related to: (1) groundwater rights; (2) reinjection procedures; and (3) surface discharge permits. Reinjection procedures and surface discharge permits have been addressed above under federal items.

The state of Oregon defines geothermal resources as those resources with temperatures greater than 121°C (250°F) and/or taken from wells deeper than 2,000 feet. The Department of Geology and Mineral Industries (DOGAMI) was given authority to regulate geothermal drilling by the 1971 Geothermal Act. Comprehensive regulations were promulgated under this statute in 1972. In 1957, the law was rewritten by the House Natural Resources Committee and was passed by

the Oregon Legislative Assembly. The 1975 law required DOGAMI to draft Blowout Prevention Rules 60 days after the bill's passage. This was done and the bill has become a law. Copies of these regulations are available at the DOGAMI office. Geothermal resources other than those stated above are considered hot groundwater and their uses are regulated by the State Water Resources Department (WRD).

Groundwater rights must be established for demands exceeding 5,000 gallons per day which is about 210 gallons per hour or 3.5 gallons per minute. All agribusiness industries considered in this project would exceed this minimum quantity. Groundwater permits for beneficial uses are for domestic and stock uses and for irrigation. Several discussions have been held with WRD administrators to also permit "heat extraction" as a beneficial use. This has not as yet proven to be an obstacle in obtaining a permit but should be included in the published rules and regulations governing groundwater use. In the absence of WRD regulations governing geothermal resource use, each new application will be reviewed on a case-to-case basis.

Both the DEQ and WRD are presently involved with permits for re-injection into groundwater reservoirs until final promulgation of the regulations contained in the Safe Drinking Water Act.

House Joint Resolution 50 was passed by the 1977 Legislative Assembly. This resolution directs the State Department of Water Resources, Geology and Mineral Industries, Energy, and Environmental Quality "to make a cooperative and coordinated effort to establish a policy and, if necessary, promulgate rules on the disposal of geothermal fluid." Two meetings have been held by these agencies, the first on August 23, 1977, and the second on October 11, 1977. Future meetings are planned. Representatives from the Region X EPA headquarters in Seattle, Washington and from the Oregon Land Conservation and Development Commission (LCDC) were invited to attend and contribute towards the success of the Legislative Directive. All institutional factors related to geothermal resources are being considered and acceptable geothermal waste disposal methods are the goals of the Interagency group.

c. Planning administrators in Klamath and Malheur Counties, Oregon are addressing geothermal resource uses when constructing their Comprehensive Land Use Plans. Several of the goals of the Oregon land use law as administrated by LCDC are indirectly related to geothermal resources. Comprehensive plans have not been completed for either Klamath or Malheur County so prospective developers of geothermal resources should communicate with the relevant County Planning Department. Citizen involvement is a major goal of the land use law but it is not anticipated that major problems will occur when developing the county's geothermal resources for agribusiness use.

IV. ENGINEERING AND ECONOMIC ANALYSIS

A. Introduction

Agriculture, wood products and recreation are the major industries in the Klamath Basin. Most people engaged in manufacturing are employed by the lumber and wood products industry.

Agriculture, food processing and recreation are the major industries in the Western Snake River Basin (Malheur County). In recent years over 95 percent of the value added by manufacturing in the county is from food processing.

In evaluating the potential of various geothermal applications to energy intensive agribusiness industries to reduce product costs, the type of farm product and quantity produced in the Klamath and Western Snake River Basins were taken into consideration. The major farm products and existing processors in the two Basins are listed in Table II.

TABLE II. Klamath and Western Snake River Basin Farm Products.
Klamath Basin, 1976

Farm Product	Processor
Alfalfa, 45,000 acres	One Pelleting Mill
Potato, 20,000 acres	Western Polymer Corp.
Onions, 2,600 acres	None
Livestock, 118,000 head	Two plants

	1976	1975
Gross Farm Income from Crops	$31,345,000	$24,269,200
Gross Farm Income from Livestock	36,703,000	29,271,000

Western Snake River Basin, 1976

Farm Product	Processor
Hay Crops, 116,000 acres	None
Potato, 11,000 acres	Ore-Ida Foods, Inc.
Sweet Corn, 3,600 acres	Ore-Ida Foods, Inc. & Am. Fine Foods
Onions, 5,800 acres	Ore-Ida Foods, Inc.
Sugar Beets, 13,100 acres	Amalgamated Sugar Co.
Livestock, 195,000 head	Four Plants

	1976	1975
Gross Farm Income from Crops	$78,407,000	$62,112,000
Gross Farm Income from Livestock	29,767,000	25,271,000

This study involved determination of the energy needs and balances, the engineering analysis necessary to convert food processing plants to geo-thermal fluids and these were incorporated into the economic analyses. Data for this report was collected in cooperation with the personnel at Western Polymer Corporation, Amalgamated Sugar Company and Ore-Ida Foods, Inc. in the two Basins. Additionally, field trips were made to California and other areas of Oregon to collect data on prospective industries for the two study areas.

Based on selection criteria presented in section IV-B,2, three potential industries: onion dehydration, alfalfa drying and greenhouses were analyzed. These three industries would be applicable in either the Klamath or Snake River Basins. For each potential process analyzed in the following sections, assumptions were made on well depth, tempera-ture, and production and transmission distances. Since these parame-ters will vary, depending on the actual site selected for development, (Figures 20 and 21) on drilling and transmission costs will enable the developer to make adjustments in costs. Changes in temperature ranges would also affect the conversion costs of equipment, and concepts devel-oped for method of utilization. It would be wise for the companies using the results of this study to develop parametric models considering con-ceptual design change resulting from various quality possibilities of the geothermal resource. In some cases, additional heat may be neces-sary from conventional fuels in order to achieve temperature for certain processes or to meet seasonal or peaking requirements.

For each process analyzed, production costs using conventional energy (fuel oil, natural gas, coal, electricity or other appropriate fuels) were determined so the economic benefits using geothermal energy could be calculated. These economic comparisons were made with cost projec-tions of conventional fuel developed by the Oregon Department of Energy. The Department forecasts annual rate increases of 8 percent (private utilities) and 7 percent (public utilities) for electricity, 7 percent for petroleum products and 10.7 percent for natural gas through 1986, and 7 percent per year thereafter.

A comparison of industrial thermal energy price projections is illustrated on Figure 22, and assumes combustion efficiencies of 100 percent for elec-tricity, 80 percent for No. 2 fuel oil and 90 percent for natural gas.

The rationale for forecasting conventional fuel cost projections by the Oregon Department of Energy is summarized in Appendix A.

The price escalations of conventional fuel exceed inflation rates for equip-ment purchase, installation, operating and maintenance costs. To show how inflation lowers the value of Present Worth calculations or increases future costs in terms of today's dollars, the following annual equivalent cost (A) formula was developed (see Appendix B for derivation):

$$A = \frac{a}{t - i} [(f/P)_n^t (P/f)_n^i - 1](a/P)_n^i$$
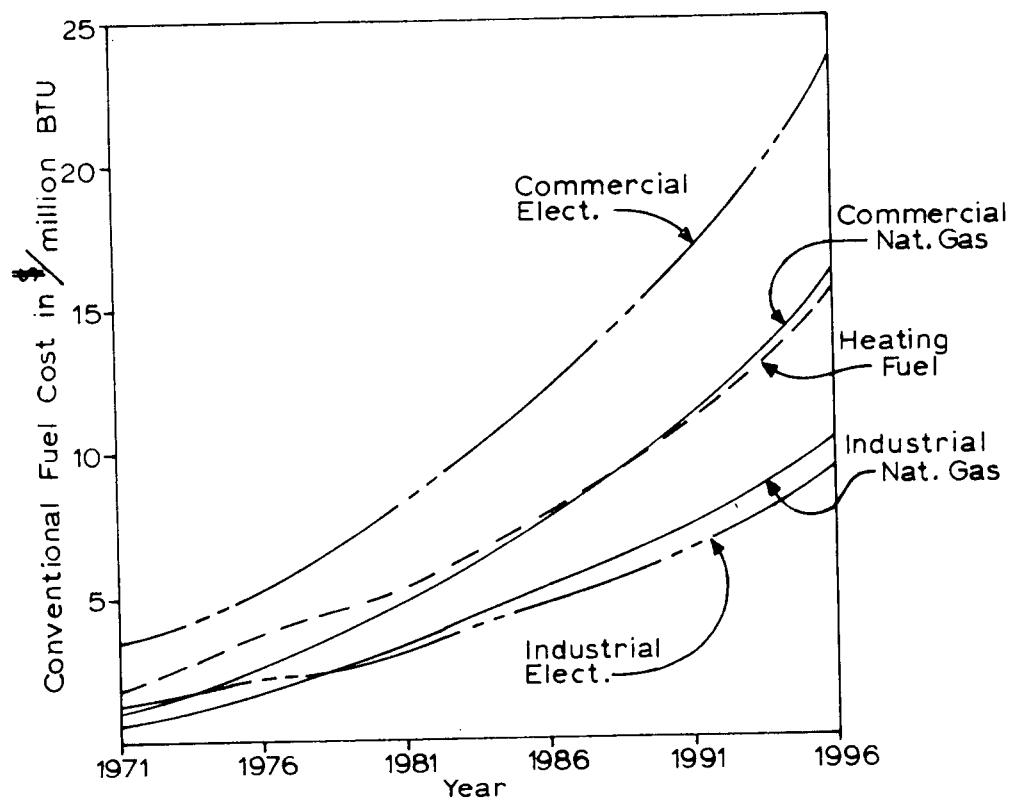
Figure 22.   Commercial and Industrial Conventional Energy
             Price Projections.

where:

A = annual equivalent cost
a = annual cost
t = annual inflation rate
i = interest rate per interest period
P = Present Worth
f = future value
p = present value
n = number of interest periods

This formula was used to consider the cost of capital or return on investment (ROI) together with a predictable inflation rate to select the optimum alternative. The formula can be used as a part of any conventional annual cost model.

B. Klamath Basin, Oregon Assessment

1. Background and Selection Criteria

The capabilities of the Klamath Basin to produce agricultural crops to supply any agribusiness industry and to supply geothermally heated water to provide energy for such industries are directly related to the physical geography of the area. The Basin and its prime agricultural lands straddle the Oregon-California border along the east side of the high Cascades in the northwest corner of the Basin and Range geomorphic province. Quite recently in geologic time, block faulting and volcanic activities caused sunken areas (grabens) to contain large lakes whose outlets were blocked by lava flows. The Klamath River cut through these flows but not until deep beds of organic materials were formed in the eutrophic lake bottoms. Most of the Basin's geothermal energy resource use has developed along the edges of the Klamath graben. Plentiful water supplies are discharged from ground water generated from water which precipitates into porous lava ash sails and porous basaltic rocks in the Cascades. Klamath Lake is the largest remaining natural water storage reservoir with an area of about 90,800 acres (about 142 square miles) and has a useable capacity of about 584,000 acre-feet. The lake and all agricultural lands in the Basin have an elevation of greater than 4,000 feet.

The climate is semi-arid, experiencing hot, dry summers, cold winters and moderate spring and fall temperatures. The average annual precipitation is 9 to 14 inches with maximums reaching more than 60 inches in the Cascades Mountain watershed area. Most of the precipitation comes as snow. The frost-free growing period in the agriculturally extensive area is 90 to 105 days with the possibility of light to killing frosts occurring any month of the year.

Agricultural activities began in the 1850s in the Basin and records of irrigated crops are as early as 1866. Major lake and marsh drainage projects were initiated in 1905 by the Bureau of Reclamation and most of the fertile farm lands are irrigated as a result of these activities. In 1964, 255,500 acres were irrigated and the quantity remains about the same today.

Considerable amounts of hay and grains are grown to provide feed for large stock raising operations. Klamath County ranchers reported 118,000 cattle and 18,000 sheep in 1976. More than 87,000 acres of hay were grown in 1976 and a total of 124,000 acres of wheat, barley and oats were reported. Grain crop yields are good with wheat yielding 47 bushels per acre in 1971 when the state average yield was 44.9 bushels per acre (Karr, 1976). Other major crops are potatoes and dehydration-type onions. About 20,000 acres are planted to potatoes each year with most of the crop going to the seed and fresh markets. Average potato yields are about the same as in Malheur County or about 350 hundredweight per acre for an income of $16,900,000 in 1976. While some onions are grown in Klamath County, Oregon, most are grown in the bordering areas in northern California.

The only agribusiness industry processing potatoes is a starch plant in Tulelake, California. An alfalfa pelleting plant runs a short seasonal operation near Klamath Falls. All other processing proceeds outside of the Basin with the raw material being transported from the area.

Geothermal energy could be utilized by dehydrator, greenhouse and aquaculture industries in the area but, as yet, this use has not been extensively pursued. Such actions could be used to reduce the wide fluctuations in farm and ranch incomes as the hot water resources are quite extensive. Greenhouse operations to grow tree seedlings, foliage plants, etc., could be used to extend the income producing season on an individual and/or cooperative basis. The Basin's shallow geothermal resources would aid in minimizing the costs of their utilization.

Comprehensive Land Use Plans have not been completed for Klamath County. County planners are awaiting the completion of this report to add the potentials for geothermal resource development to the economic portions of their plans.

Selection Criteria

In the Klamath Basin where agriculture is the major industry, there are only two agriculture processing plants other than dairies. These are the potato starch extraction plant of Western Polymer Corporation situated on the Oregon-California border 21 miles south of Klamath Falls and a pelleting mill located about 7 miles east of Klamath Falls.

In order to select agriculture processing industries that can benefit from the geothermal resources in the Basin, the following assumptions were made regarding the resource:

    a.   Geothermal resources exist in quantities at a maximum temperature of 195° to 230°F in several separate localities of the Klamath Basin. Temperatures above 230°F may be found by exploration and exploitation of deeper reservoirs, however, at the time of this study the highest temperature discovered by drilling is 235°F.

b.   Geothermal reservoirs can be drilled and tested to depths of 1500 to 3000 feet in depth and found to be productive at rates which will allow commercial development.

c.   Geothermal fluid can be used directly in processing equipment (heat exchangers, fan coils, etc.) without adverse effects of fouling due to corrosion or scaling.

d.   Rejected geothermal waters shall be injected into the ground via a well.

Potential processing industries were identified that could benefit from the temperature of the resources in the Basin. The industry selections were based on existing and potential crops grown in the Basin in terms of quantity and potential increase in production. Figures 23 and 24 illustrate processes and product matches that best fit the geothermal temperatures available, including consideration for using the geothermal energy as a preheat.

The final selection of applications to be analyzed and the reasons for their selection are as follows:

   - Onion Dehydration
   - Alfalfa Dehydration
   - Potato Starch Drying
   - Greenhouses

Onion Dehydration was selected because large quantities of low temperature energy is consumed in the process and the existence of an onion producing area in the Basin as well as the possibility of a large number of farms shifting to onion production.

Alfalfa Dehydration was selected because of the large quantities of alfalfa raised in the Basin and the potential for a large foreign export market of alfalfa processed with low temperature to retain xanthophyll and vitamin A.

Potato Starch Drying was selected because of an existing plant (Western Polymer Corporation, located near a resource site) that uses expensive LPG in a low temperature drying process.

Greenhouses were selected because of the large number of firms interested in locating in the Klamath Basin and the favorable location to transport products to markets both North and South. In addition there is a large need to supply seedlings for reforestation in the immediate area. The growing season is fairly short, 90 to 105 days in the Basin, thus greenhouses could extend the seasonal agricultural economy and provide jobs to reduce the 8.3 percent unemployment in the area.
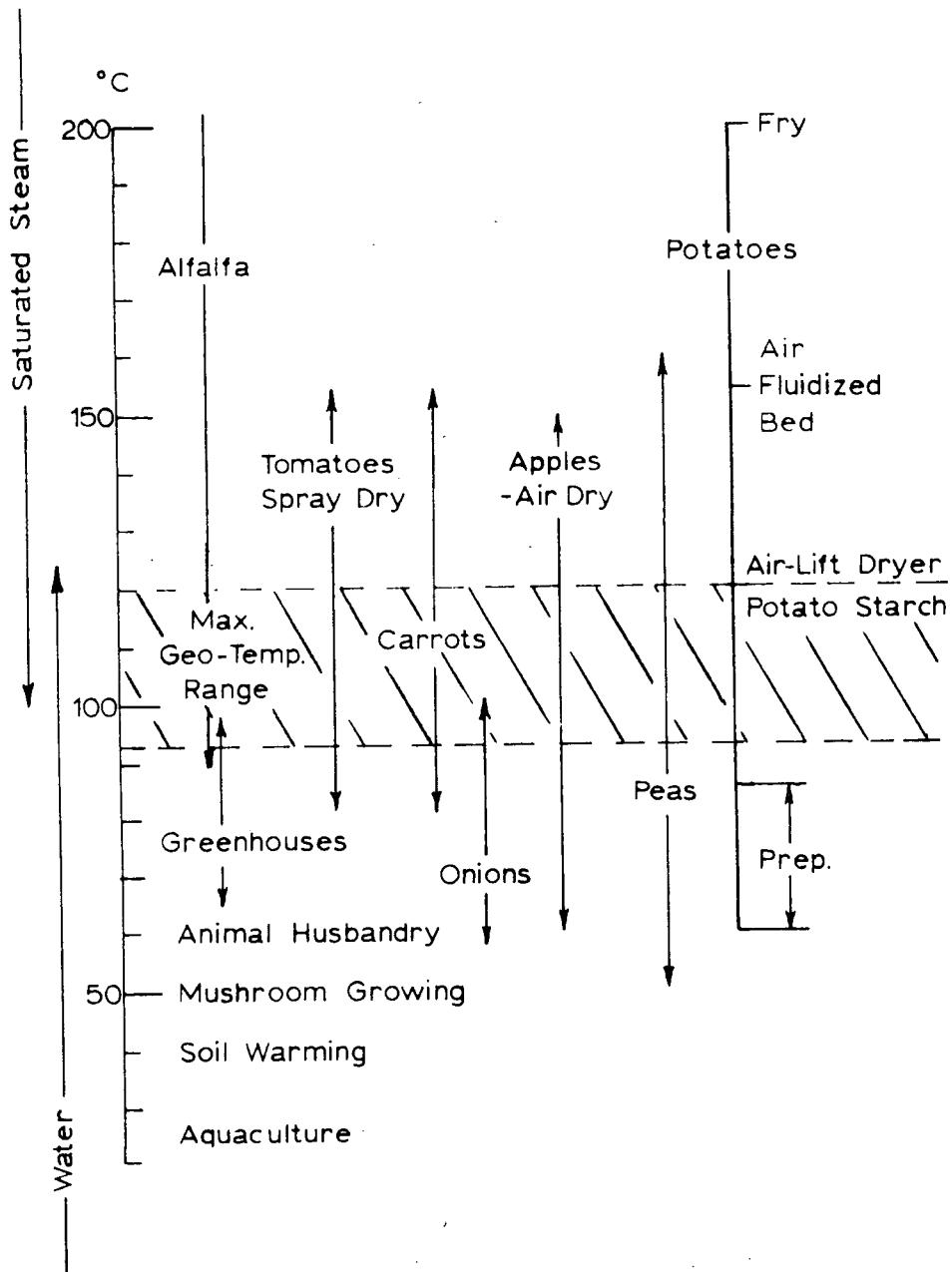
Figure 23. Process Temperatures for Potential Klamath Basin Products.
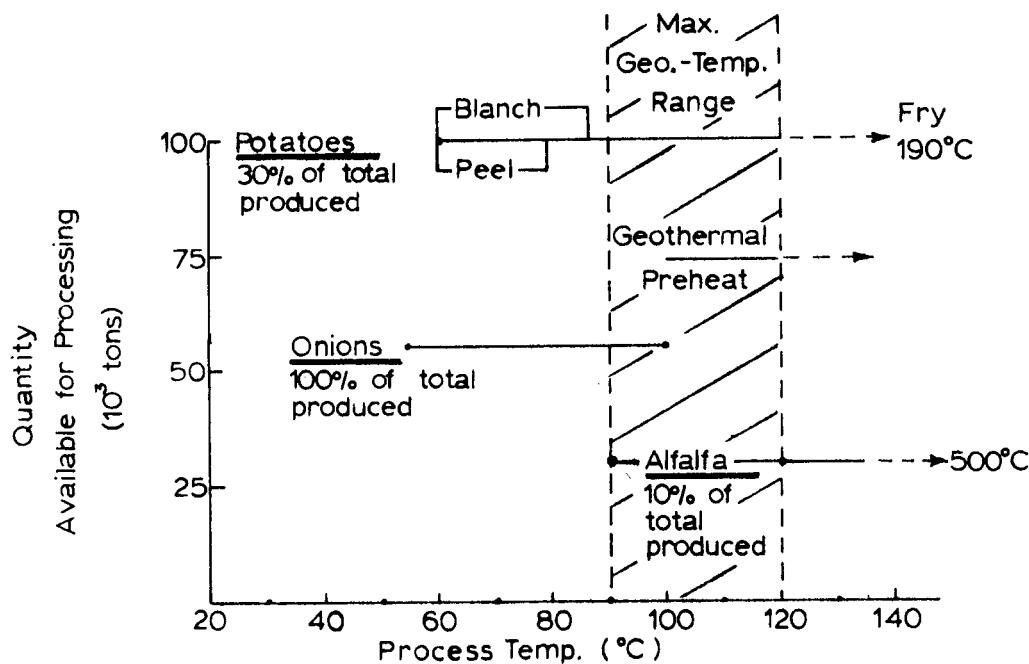
Figure 24. Existing Klamath Basin Agricultural Crops and Their
Required Process Temperatures (1977).

2. Onion Dehydration

    a. General Description

    All onions for processing are grown from specific varieties best
    suited for dehydration. Specific strains of the Creole Onion,
    Southport Globe Onion, and the Hybrid Southport Globe were devel-
    oped by the dehydration industry. They are white in color and
    possess a higher solid content which yields a more flavorful and
    pungent onion.

    Onion dehydration involves the use of a continuous operation,
    belt conveyor using fairly low-temperature hot air from 100° to
    220°F. The heat originally was generated from steam coils, but
    now natural gas is more popular. Typical processing plants will
    handle 10,000 pounds of raw product per hour (single line), re-
    ducing the moisture from around 83 percent to 4 percent (1,500
    to 1,800 pounds finished product). These plants produce 5 mil-
    lion pounds of dry product per year using from 0.15 to 0.20 therms
    per dry pound produced (+0.06 therms of electrical energy), or
    4,000 BTU per pound of water evaporated.

The Tulelake area of California adjacent to the Oregon border will produce from 2,500 to 2,600 acres of Southport White Globe dehydrating onions this season, 1977. Approximately 1,900 acres were planted in 1975 and only 131 acres in 1976. The onions are grown under contract between onion companies and the individual farmer. In 1977, four onion companies were involved in dehydrating the onions: Gentry International and Gilroy Foods, both of Gilroy, California; Basic Vegetable Products of Vacaville, California; and Rogers Brothers of Turlock, California. Approximately 45,000 pounds per acre will be harvested for a total of 58,500 tons. The product will be sold for $3.15 per 100 pounds (loaded in trucks) to the four onion dehydration companies. Onions are not grown in the Oregon side of the Klamath Basin due to the additional cost of transporting them across the state line (estimated at $0.15 per 100 pounds) to the processing plants. The season lasts from late April to harvest time in October and November. This season could be extended in the Klamath Basin by raising onion transplants in greenhouses, thus increasing the processing period. The single-line, four-stage dehydrator requires 35.0×10^6 lb of raw products which would produce 5.2×10^6 lb of dehydrated product in a 150-day season. This is equivalent to the production of about 440 acres of good onion-producing land. It appears that the existing crop from the Tulelake area could support from five to six of the single-line dehydrators operating 150 days on a 24-hour-day basis, and if plants could be set up on the Oregon side, many farmers would enter the onion-growing business. The advantages for locating a dehydrating plant in the Basin, in addition to using geothermal energy, are the cooler climate, 4,100-foot elevation, for excellent field storage conditions and the low relative humidity of the area. The disadvantage is a short growing season which could be compensated for by greenhouse transplants.

One processing plant has been toured and discussions held with an equipment manufacturer to better understand the general processing steps and energy inputs. Some general details were obtained from these discussions. However, due to the competitiveness of the industry, specific details and energy requirements were difficult to obtain. Most of the details have been obtained from "Economic Study of Low Temperature of Geothermal Energy in Lassen and Modoc Counties, California," by VTN-CSL for the State of California, 1976, and "Application of Solar Energy to Continuous Belt Dehydration," Final Report by Trident Engineering Associates, Inc., for ERDA, 1977.

An example of one type of processing equipment, the Proctor dehydrator, is a single-line unit 212 feet long and 12.5 feet wide, requiring 86,500 ft^3 of air per minute and up to 40 million BTU per hour. Due to the moisture removal, the air can in some cases only be used once, and thus is exhausted. Special silica gel--Bryair, desiccation units are required in the final stage. Approximately $200,000 in fuel are thus used for a single-line dryer in a year's operation (180 days).

b. Processing Steps

Onion dehydration using a continuous conveyor dryer involves the following basic steps: a) harvesting, b) transporting to the plant, c) curing, d) washing, e) slicing, f) dehydration in four stages, g) milling, and h) packaging. Each of these steps is discussed in detail for a Proctor (Proctor and Schwartz, Inc. of Philadelphia) dehydrator. A cross-sectional diagram of a typical dryer is shown in Figure 25.
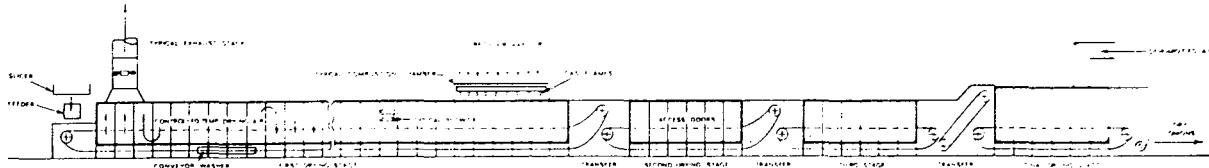
Figure 25. Proctor Continuous Automatic Onion Dehydrator.

Harvesting is accomplished mechanically by specialized equipment that is designed and fabricated by the processing industry. Harvesting is accomplished by a small crew of 20 to 30 people used to inspect the onions and to operate the equipment. The onions are topped, dug, inspected, and loaded into bulk trucks holding about 50,000 pounds each.

The trucks loaded with onions are taken directly to the plant. They are loaded into large curing bins where excess moisture is removed by passing large volumes of heated air (100°F) through the onions. Curing conditions the onions so that peeling and processing can be accomplished successfully.

After curing for 48 to 72 hours, the onions are passed into the processing line. The earlier method of scooping up the onions with a tractor has been replaced with an automatic conveyor system that gently carries them to the preparation line. Machines

automatically remove any tops that may remain attached to the onions. They are than inspected, washed in a high-pressure washer, soaked in a stainless steel tank to remove sediment, washed again in a high-pressure washer, and resoaked in a bath of highly chlorinated water in order to reduce bacteria to the lowest possible level. The onions are then reinspected and placed in stainless steel surge tanks. Two large stainless steel tanks are used so that one can be washed as the other is being used. The onions are fed out of the surge tanks into the slicers. Razor-sharp rotating knives cut the onions into uniform slices, which are then passed to the dryer.

From the slicers a continuous and uniform flow of onions is conveyed to the wiper feed that carries the sliced product laterally across the open feed end extension. Here the onions are carefully transferred to the dryer conveyor for the first stage of drying. This is the most critical stage, where, under high-volume air flow conditions and with moderately high temperatures, the bulk of the water is rapidly removed from the onion. The moisture content of the onions is reduced from an initial 83 percent to 25 percent. This is called the "A" stage, where onion loading depth is approximately four inches.

Absolute uniformity and controlled depth of loading on the dryers is necessary to prevent "pinking," an enzymatic discoloration that can take place in the onion slice if proper drying conditions are not maintained. The pure white color of the discharged product from this drying stage is a test of the high quality of the product. Normal drying temperature for stage "A" is around 220°F; however, temperatures as low as 180°F can be used. The lower temperature will increase the processing time; however, the quality will be improved.

High-powered blowers and exhaust fans move the air over natural gas burners, and through the beds of onions on the dryer conveyor, to evaporate the necessary tons of water removed from the product each hour. Close air volume and pressure control must be maintained in all parts of this drying stage as the air moves up and down through the bed to obtain product drying uniformity. Automatic temperature controllers and a long list of safety devices control the continuous operation.

At the proper point in the drying process, the onions are automatically transferred to the second stage ("B" stage) of drying where, under reduced temperature conditions and deeper bed loadings (approximately 12 inches), the difficult to remove diffused water is slowly withdrawn. Here, moisture content is reduced to 10 percent. At the special transfer zone, the onions are gently handled by rotary devices that assure full removal from the first-stage dryer and separation removal of clumps for uniform second-stage loading.

The second stage of drying transfers to the third stage ("C" stage) with even deeper loading (approximately 30 to 40 inches deep), as the deeply diffused water becomes even more difficult to remove. Moderating temperatures and air flows are used to maintain close product temperature control as a steady evaporation of water is reduced from each onion slice and the evaporative cooling effect can no longer be counted on to maintain the low product temperature required for maximum product quality. After leaving the "C" stage, moisture content is down to 6 percent.

A special unloader takes the now nearly dry onions off the third-stage conveyor, transferring them to the elevating conveyor for the fourth and final stage of dehydration. Here, conveyor loading depths up to six feet are used for final moisture reduction and equilibration. Dehumidified air from a two-stage desiccation unit is counterflowed through this deep layer to bring the finished onions to the point (about 4 percent moisture) where milling can best be accomplished and shelf life maintained.

After drying, the onions are passed over a long stainless steel vibrating conveyor that gently carries them to the milling area. In the mill, skin is removed by aspirators from the onion pieces. The onions are then milled into sliced, large chopped, chopped, ground, granulated and powdered onions.

c.   Power Production and Energy Requirements

The energy requirements for the operation of a dryer will vary due to differences in outside temperature, dryer loading, and requirement for the final moisture content of the product. A single-line Proctor dryer handling 10,000 pounds of raw product per hour (1,500 to 1,800 pounds finished) will require about 5.0×10^8 BTU/day, or for an average season of 150 days, 7.6×10^{10} BTU/season, using approximately 0.15 therms per pound of dry product. This is estimated to cost from 4¢ to 5¢ per pound of finished product.

The energy is provided by natural gas; air is passed directly through the gas flame in stages A and B, and over steam coils in stages C and D. The steam coils are necessary to prevent turning of the onions in the last two stages.

In addition to the heating requirements, electrical energy is needed for the draft and recirculation fans and small amounts for controls and driving the bed motors. Total electric power required for motors is from 500 to 600 horsepower, or about 1×10^4 KWh/day, or 2×10^6 KWh/season. This amounts to 0.01 therm per pound of finished product and increases to about 0.06 therm per pound when all electrical requirements are considered.

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The details of each stage of a typical process are as follows:

Stage	Size (length)	Motor output (hp)	Air Temp. °F	Air Volume CFM*	Depth of onions	Moisture Content
Curing bins	100 x 100	--	100	variable	variable	
transfer						80-85
A (4 compartments)	73 ft	400	190-220	230,000	4"	
transfer						20-25
B (2 compartments)	25 ft	90	155-170	60,000	12"	
transfer						12-16
C (2 compartments)	25 ft	70	135	70,000	30-40"	
transfer						6-8
D (2 compartments)	25 ft	40	120	20,000	60-70"	
transfer						4-5

*Some air may be recirculated depending upon moisture content.

In general, four stages (A through D) are preferred; however, if the ambient air humidity is below about 10 percent, stage D can be eliminated. This is not felt to be possible in the Klamath Basin. Also temperature and number of compartments in each stage may vary.

Stage D, supplying desiccated air with a Bryair unit, reduces the moisture content of the product to a point below that of the ambient air. The unit is divided into two sides: the process side, which supplies desiccated air to the dryer after it has been passed through silica gel beds; and the reactor side in which heated air is passed over the silica gel beds in order to remove the moisture which had been absorbed in the process side.

The process air is drawn in from the outside under ambient conditions of temperature and humidity, passed through a filter and a cooling coil, and then is circulated through the dry silica gel beds where some of the moisture is absorbed. The process air then is drawn out by a fan and directed to the D2 stage of the dryer. This process air leaves the Bryair unit at a temperature of about 120°F with a moisture content of about 30 grams per pound (4 g per kg).

On the reactor side, ambient air is drawn into the intake and passed over a gas burner which heats the air to about 250°F, after which the air is circulated through the silica gel beds so that the moisture which had been absorbed in the process side is removed.

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A suction fan on the discharge side then exhausts the moisture-laden reactor air to the atmosphere at temperatures of from 150° to 225°F. A slight pressure differential is maintained between the process and reactor sides so that air is prevented from leaking to the process side from the reactor side.

In summary, total energy requirements are as follows: Single-line Proctor dehydrator approximately 210 feet long by 12.5 feet wide; average input 10,000 pounds wet product (15-20 percent solids) producing 1,500 to 1,800 pounds dry product (95-96 percent solids) per hour requires 2.2×10^7 BTU/hr of heat energy or 9.5×10^{10} BTU/season (180 days).

A specific example of a proctor dehydrator is detailed in Table III, and Figures 26 and 27. The total energy requirements, using natural gas as a fuel, varies from 21 to 26 x 10^6 BTU/hr depending upon the ambient air varying from 65° to 40°F. Air flows depend upon temperature and amount of re-circulated air--which could only be estimated.

TABLE III
Onion Dehydration

Stage	Air Temperature	Heat Supply	Approximate HE opening size	Estimated air flow	Estimated* BTU/hr x 10^6
A1	210°F	gas burners	11' x 3' = 33 ft^2	29,000	5.0
A2	210°F	gas burners	14' x 3' = 42 ft^2	29,000	5.9
A3	190°F	gas burners	13' x 3" = 39 ft^2	41,000	3.6
A4	180°F	gas burners	15 x 3 = 45 ft^2	41,000	4.9
B1	160°F	gas burners	14 x 3 = 42 ft^2	17,000	3.6
B2	145°F	steam coils	11 x 3 = 33 ft^2	19,000	1.0
C	130°F	steam coils	15 x 3 = 45 ft^2	20,000	0.4
D	120°F	steam coils	29 x 3 = 87 ft^2	10,500	0.6
Bryair	300°F	gas burners	25	6,300	1.0
				Total:	26 x 10^6

*assuming ambient at 40°F; total = 21 x 10^6 BTU/hr at 65°F ambient.
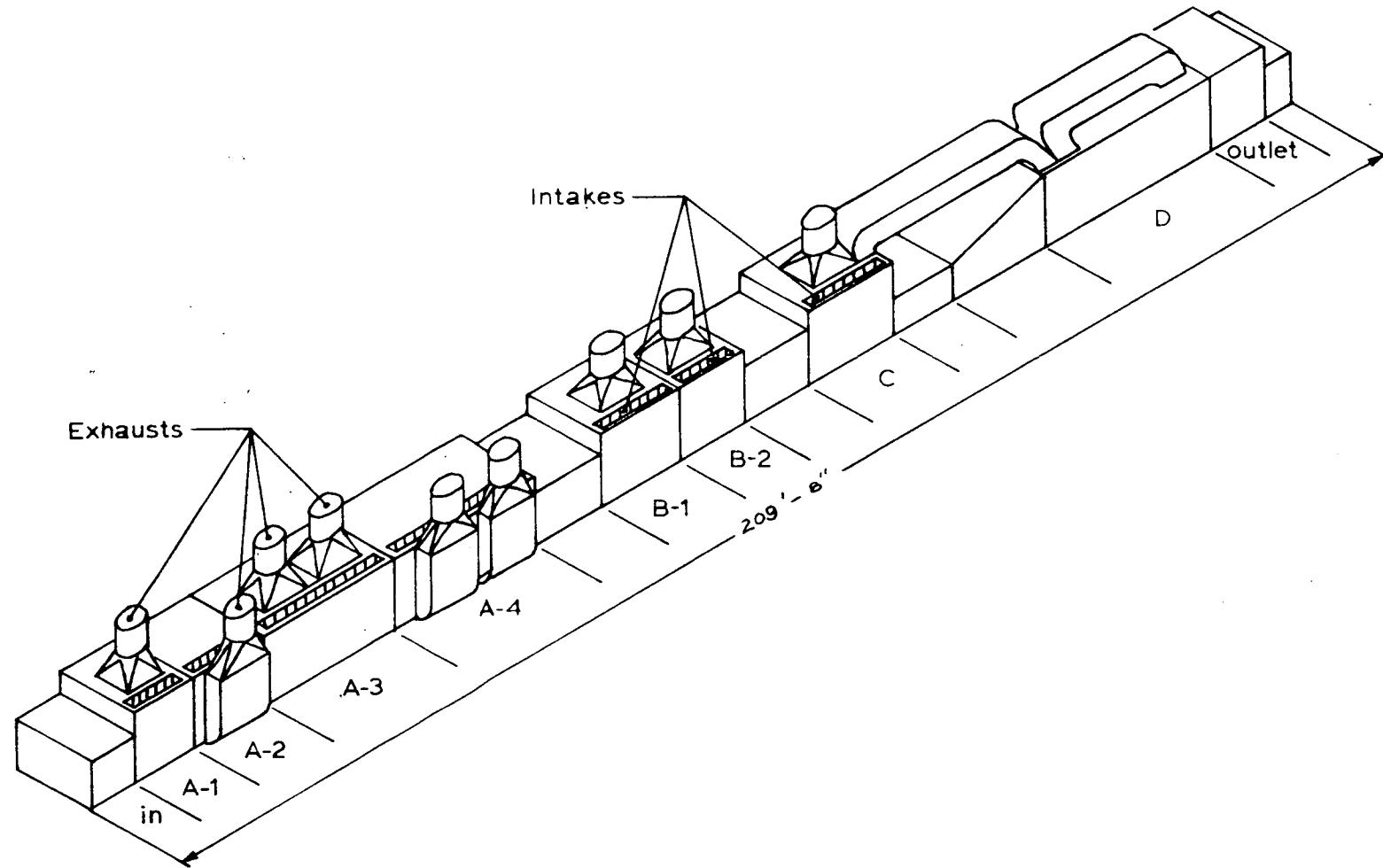
Figure 26. Single-Line Onion Dehydrator.

Exhausts

Fresh Air

Gas Heat 250°F

Fresh Air → BRYAIR Air Dryer

20 HP   15 HP   15 HP ea.

Fan

15 HP   5 HP

200°F   195°F   3,25HP   180°F   4, 20 H.P.   145°F   135°F   Steam Heat   120°F   120°F

15HP

Inlet   2,30 HP   air   4, 25 H.P.   175°F   2,15 H.P.   2,10 H.P.   Steam Heat   2,15 H.P.   4,10 H.P.   Disch

| A-1 | A-2 | A-3 | A-4 | | B-1 | B-2 | C | | D |

72'-10" A Stage   25'-2" B Stg.   14'-8"   28'-8" D Stg.

209'-8"
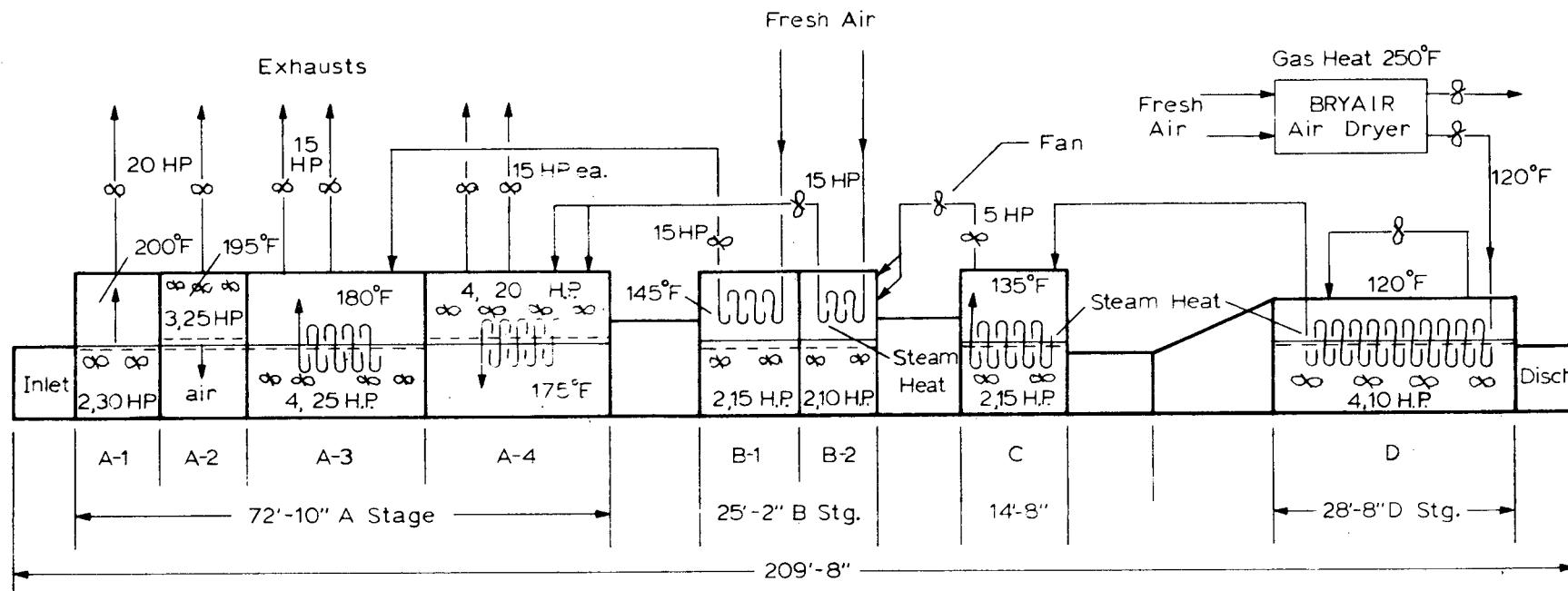
$T_{amb.}$					Energy Into Air BTU/hr. $\times 10^3$			Bed Width 12'6"		
65°F	4,260	4,897	3,164	4,200	2,800	783	375	218	245	892
40°F	5,040	5,839	3,597	4,895	3,624	987	420	292	264	920

Figure 27. Temperature and Energy Requirements for Each Compartment of a Single-Line Onion Dehydrator.

d. Geothermal Applications

Using the specific example detailed in Table III and Figures 26 and 27, a design was made to convert the Proctor dehydrator to geothermal energy. Using a 20°F minimum approach temperature between the goethermal water and process air, a well with 230°F water is required. This temperature is available in the Klamath Basin; however, a deeper well (up to 2,000 feet deep) will probably be required.

The first-stage air temperature can be as low as 180°F; however, temperatures above 200°F are desirable, as indicated by people in the industry.

Figure 28 indicates Design I using 230°F water. The line has to be split between compartments A-1 and A-2, since both require 210°F air temperature. A total of 900 gpm is required. Two wells can probably supply this volume, as 500 to 600 gpm have been pumped from existing wells in the Basin. The Bryair desiccator requires 300°F on the reactor side, thus only half of the 1.0×10^6 BTU/hr energy requirements can be met geothermally. Geothermal heat will be used for preheating to 175°F, with natural gas or propane used to boost the air to 300°F. The waste water from the Bryair preheater has a temperature of 192°F, thus this could be used for space heating, greenhouses or other low-temperature energy needs. The waste water would be returned by an injection well.

Design I considers the ambient air to be 40°F (worst conditions), while Design II considers a 65°F air temperature. This will reduce the required flow to 760 gpm, however, still requiring two production wells.

Design III uses 220°F geothermal water and 200°F air temperature for compartment A-1. This requires 975 gpm, or again two wells.

In compartments A-1, A-2, A-3 and A-4, four finned air-water heat exchangers in parallel would be required to satisfy the energy requirement and water velocity flows. The remaining stages would require from one to two heat exchangers in each compartment, depending upon the energy requirements.

The details of the flow patterns for Designs I, II and III are shown in Figures 28, 29 and 30.

The layout of the plants and wells are showing in Figure 31. A 1,000-foot production well spacing is assumed, each 2,000 feet deep. The supply line will be insulated asbestos cement and buried.

GEOTHERMAL ONION DEHYDRATION
Design I
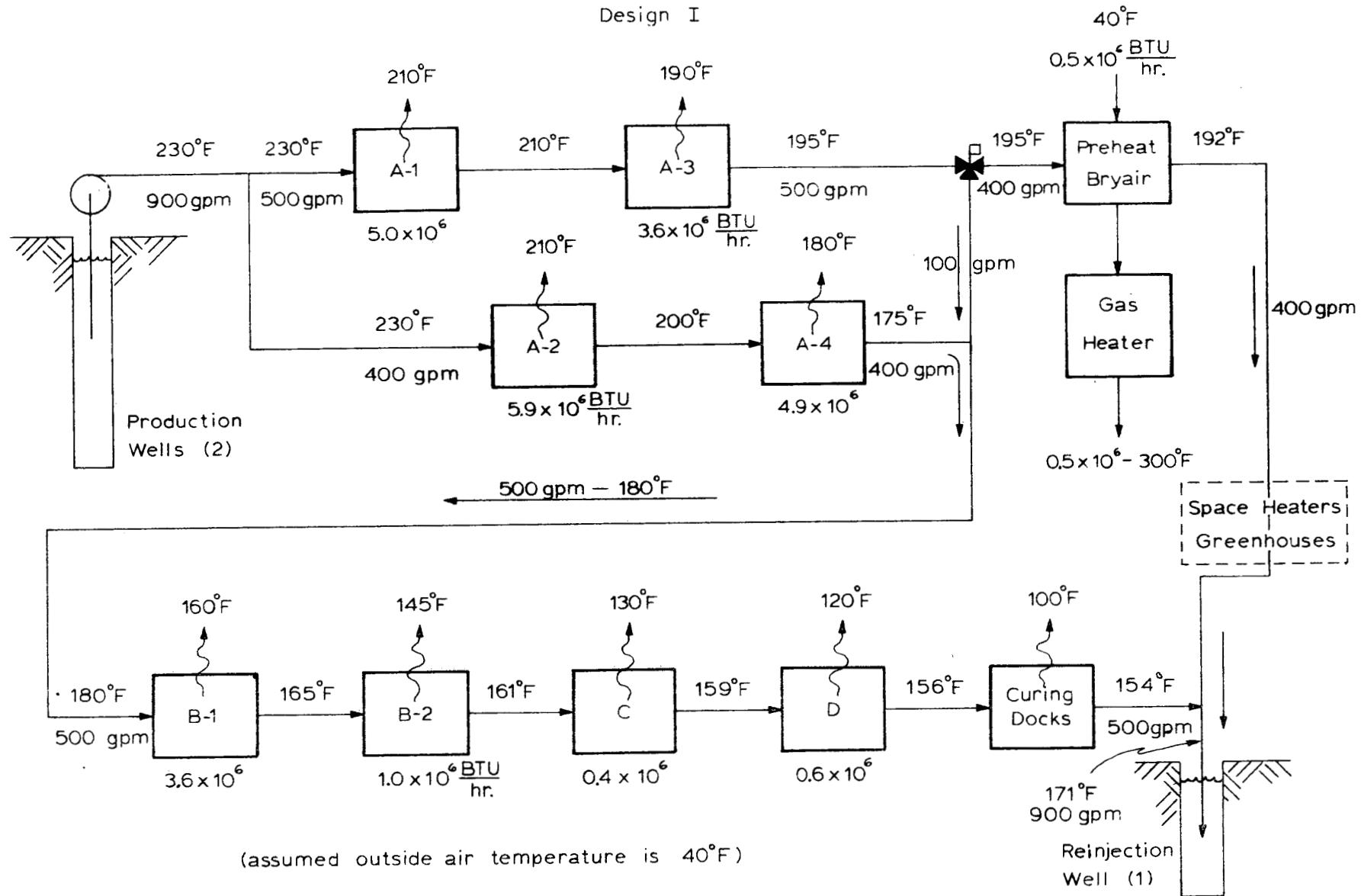
Figure 28. Design I--Single-Line Onion Dehydrator Using 230°F
Geothermal Water and 40°F Ambient Air.

(assumed outside air temperature is 40°F)
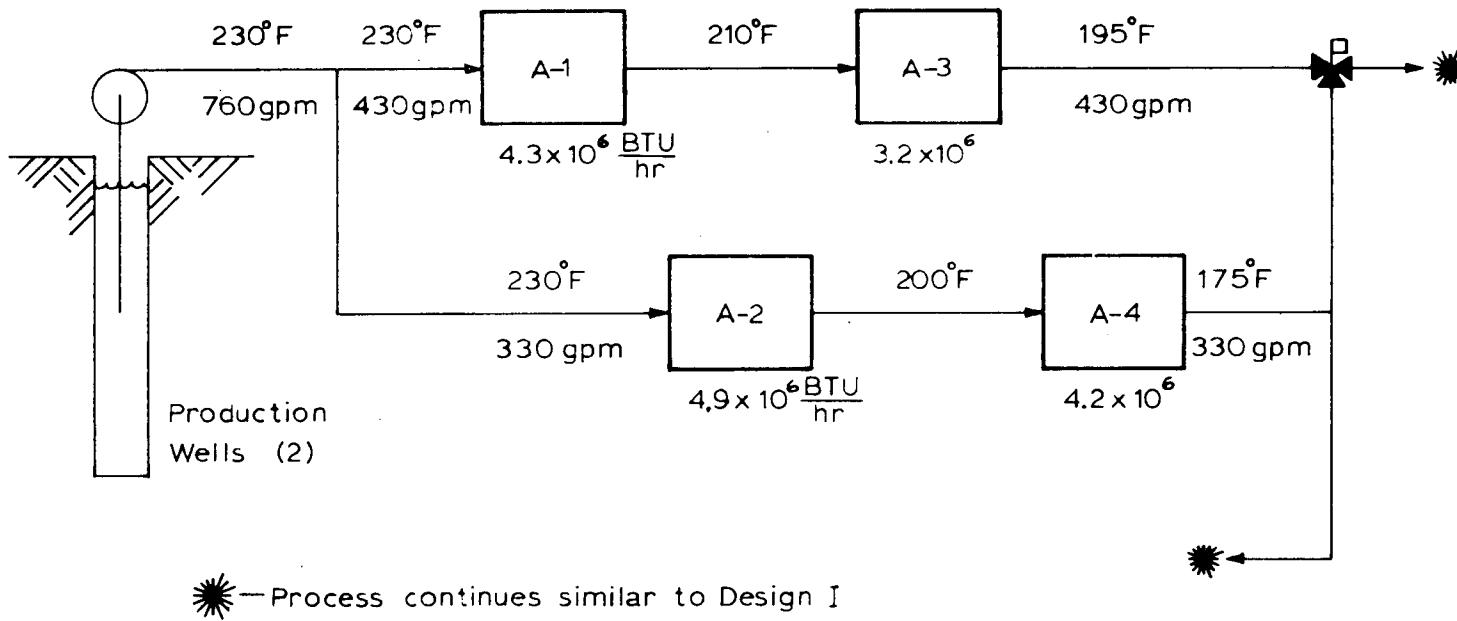
GEOTHERMAL ONION DEHYDRATION

Design II

(assumed outside air temperature is 65°F)

Figure 29. Design II--Single-Line Onion Dehydrator Using 230°F Geothermal Water and 65°F Ambient Air.
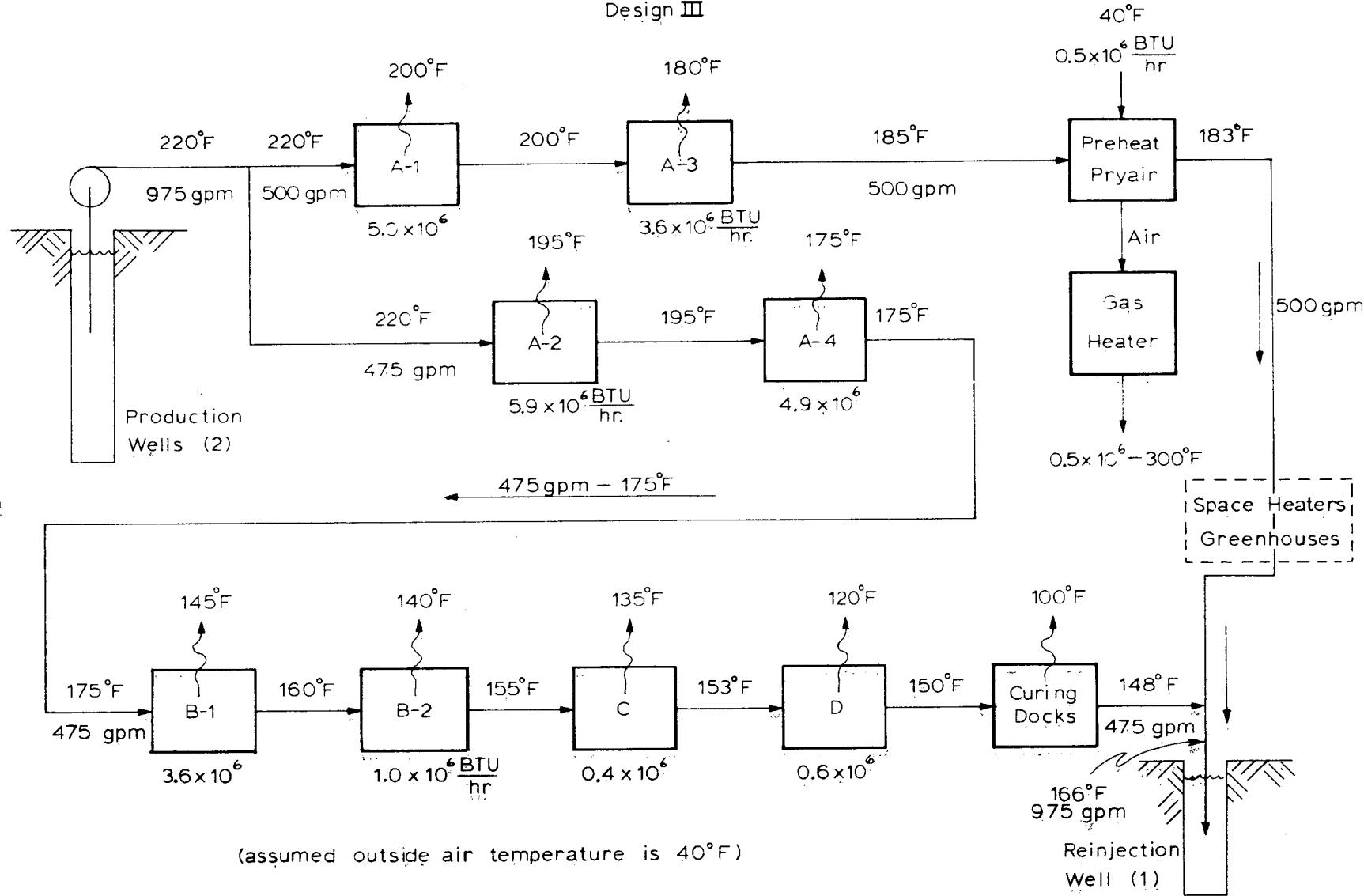
Figure 30. Design III--Single-Line Onion Dehydrator Using 220°F Geothermal Water and 40°F Ambient Air.

LAYOUT
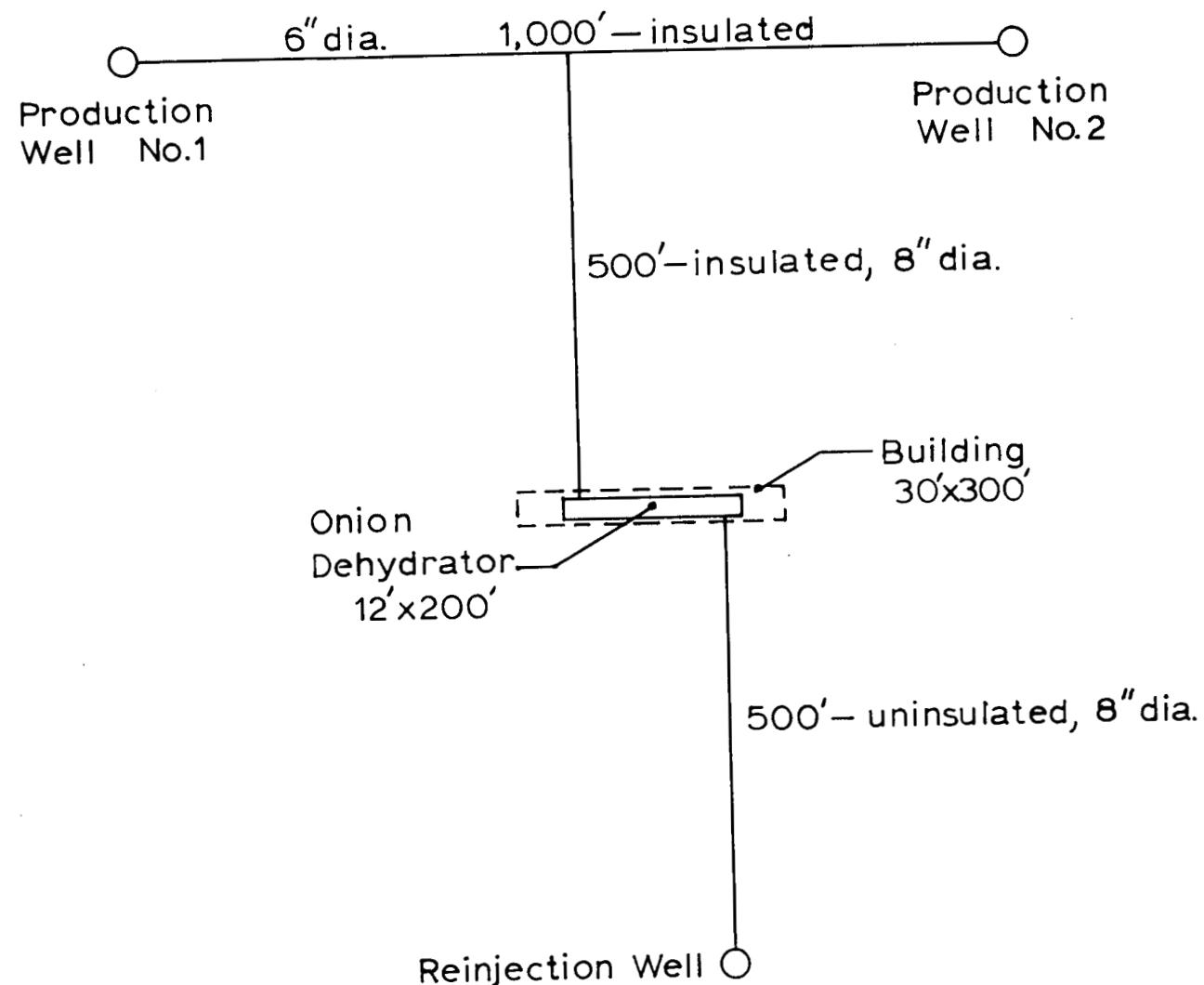
Figure 31. Single-Line Onion Dehydrator Layout of Plant and Wells.

If lower-temperature geothermal waters were encountered (below 200°F), then not all of the energy could be supplied to Stage A geothermally. Geothermal water would then be used as a preheater, with natural gas providing the energy for the final temperature rise. A design of this type for compartment A-1 was considered in the Trident Report (1977) for the Solar Division of ERDA.

e.   Economic Analysis

The economic analysis of onion dehydration does not consider investment tax credits on tangible costs, tax reduction due to write-off of intangible costs, depletion allowances, or tangible asset depreciation due to the fact that this project involves starting new facilities which could take up to five years to pay back the additional capital investment as compared to conventional systems. It is not known what kind of ownership or the tax structure that would be involved, nor what method of depreciation would be appropriate. Therefore, the analysis is ultra-conservative and all federal tax incentives for capital investment and use of geothermal energy would increase the profit margins considerably over these figures.

Since there currently are no onion dehydration plants in the Klamath Basin, the cost analysis for an onion dehydration plant was done by investigating the cost difference in establishing a dehydration plant using conventional fuel (natural gas) versus geothermal energy.

The cost of capital was established at 9 percent per annum and project life was estimated at 20 years. Maintenance costs are expected to increase at 6 percent annually. Electrical power costs are projected to inflate at 8.5 percent per annum through 1986 and at 7.58 percent thereafter. Natural gas costs are projected to increase at 11.2 percent per annum through 1986 and 7.5 percent thereafter. Using the annual equivalent cost formula for inflation with the above assumed inflation rates (Oregon Department of Energy, 1977), the following were calculated:

1.   20-year annual equivalent for $1 of maintenance cost = $1.56

2.   20-year annual equivalent for $1 of electric power cost = $1.87

3.   20-year annual equivalent for $1 of natural gas cost = $2.18

Break-even analysis indicates that a dehydration plant would
have to operate 180 hours per year in order to make the geo-
thermal system competitive with natural gas. The onion harvest
season in the Klamath Basin is approximately two weeks. Assum-
ing a two-week processing supply of onions, 24-hour operation
for 14 days would be 336 hours of operation annually which
would provide a $31,454 advantage to the geothermal system.
Storage facilities could extend the processing period greatly
and starting sets in greenhouses would provide an even longer
processing season. It should be noted that the return fluid
is very suitable for a large 15-acre greenhouse complex, as
described in this report under Section IV-5.

TABLE IV
Onion Dehydration Plant

Estimated Capital Costs for Geothermal System

		20-year annual equivalent cost @ 9%
Heat exchangers	$ 50,000	
Piping 2000' @ $5/ft	10,000	
Valves and fittings	5,000	
Instrumentation	5,000	
Electrical wiring	5,000	
Design modification--engineering	5,000	
	$ 80,000	$ 8,763.72
2 production wells 2000' @ $51,500/well	$103,000	
6" insulated pipe 1000' @ $16/ft	16,000	
8" insulated pipe 500 ft @ $23.50/ft	11,800	
8" uninsulated pipe 500 ft @ $9.50/ft	5,000	
1 return well 1000'	26,000	
2 deep well pumps 60 hp $15,000 each	30,000	
	$191,800	$21,011.01
Annual Costs		
Cleaning and adjustment of heat exchangers	$ 2,000	
Replacement parts and labor	3,500	
Pump/line/well maintenance	2,500	
	$ 8,000	$12,480
Total Annual Equivalent Fixed Costs		$42,255

Annual Energy Costs (variable)	Cost today per hour	20-year annual equivalent cost @ 9%
Electrical energy for pumps 2-60 hp 80% efficient = $\dfrac{150\ hp}{1.341}$		
112 KWh @ .01085/KWh =	$1.2136	$3.702
Natural gas for Bryair	1.10	4.037
Total 20-Year Annual Equivalent Costs		$7.739/hr

Total Annual Equivalent Costs = 42,255 + $7.74/hr

Capital Costs for Conventional System

		20-year annual equivalent cost @ 9%
Cost of natural gas system and boilers	$10,000	$1,095
Cleaning and adjustment of natural gas boilers	2,000	3,120
Replacement of natural gas parts	1,000	1,560
Total annual equivalent fixed costs		$5,775
Annual Energy Costs (variable) 26 x 10^6 BTU/hr @ .22/therm 90% efficiency	57.20	$210/hr
Total annual equivalent costs	$5,775 + $210/hr	

Using these costs, the break-even point can be found in annual hours of operation.

Difference in fixed cost:
$42,255 - $5,775 = $36,480 higher for geothermal

Contribution per hour of geothermal system:
$209.924 - 7.739 = 202.185/hr

Break-even occurs at $\dfrac{\$\ 36,480}{202.185} = 180.43$ hrs

BREAK-EVEN ANALYSIS

Onion Dehydration Plant
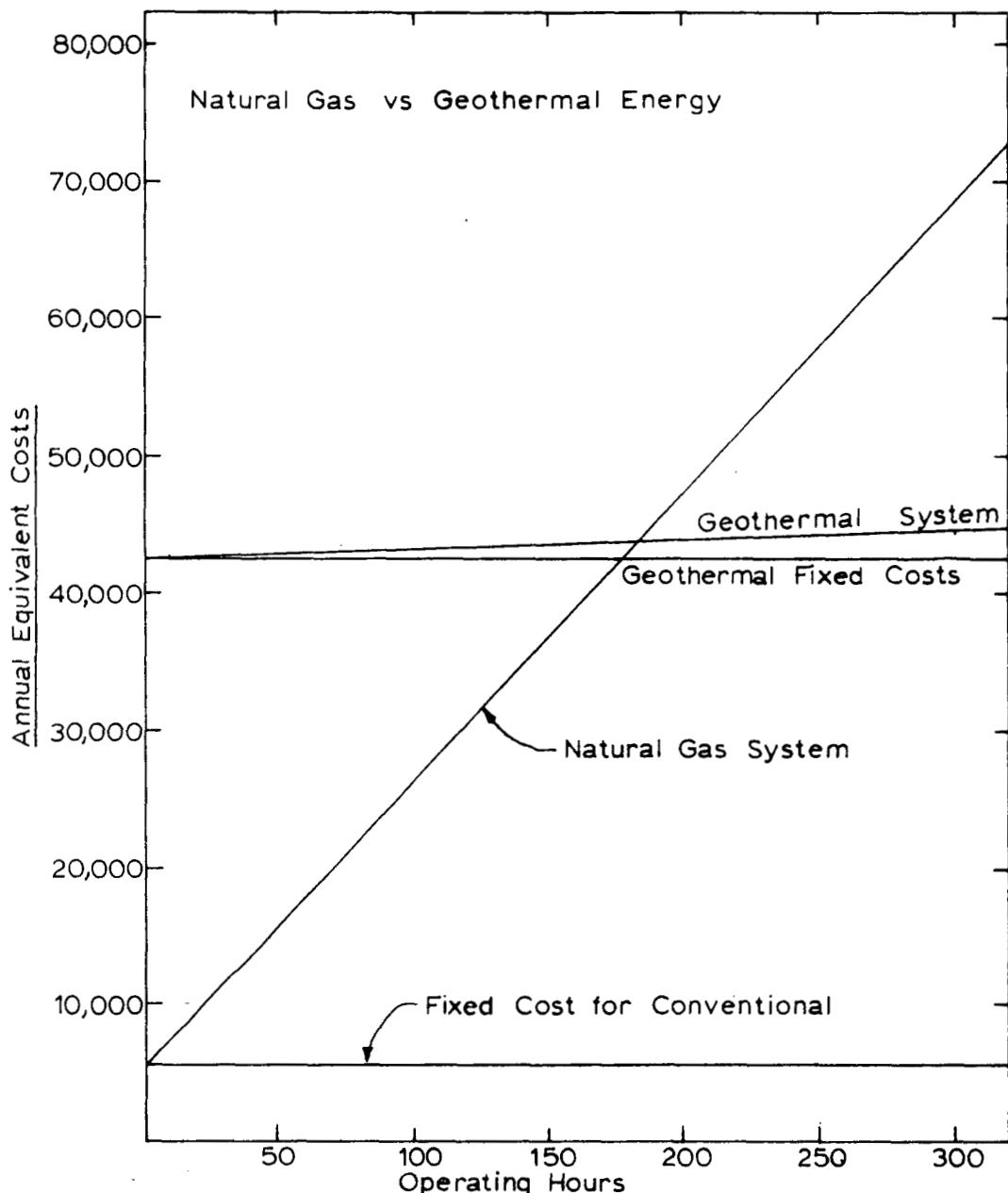
Figure 32. Onion Dehydration Plant Break-Even Analysis for Operating Hours.

3. Alfalfa Dehydration

   a. General Description

   A total of 1,386,000 tons of alfalfa hay were produced in Oregon in 1976. Approximately 70 percent of this production is used within the state. The largest domestic market is California. A survey indicates that approximately 10 to 15 percent of the alfalfa hay is cubed or pelletized. Alfalfa cubes and pellet exports in 1976 amounted to 25,112 tons, at an average price of approximately $100/ton. Exports to Japan amounted to over 99 percent of the total.

   Most pelletizing includes a mixture of alfalfa, grass and oat hay, as well as additives of molasses and other food supplements. The Klamath Basin has a three-month season (three cuttings) from mid-June to late September. Approximately 45,000 acres are in production producing about 4-1/2 tons per acre or 202,500 tons total per year. Approximately half of the amount goes to dairies for feed over the winter and the majority of the other half is shipped out of the Basin (at about $20 per ton for transportation). The alfalfa is normally field (sun) dried to about 10 percent moisture and sold for $55 to $75 per ton. Klamath Falls has a small pellet mill and Alturas, California, has a cuber. However, neither requires heat for drying the product, as it is all field (sun) dried. The Boardman area of Northern Oregon is a large producer and processor of alfalfa. Two basic products are made from the dehydrated alfalfa: pellets and cubes. The cubes are about 1-1/2 inches x 1-1/2 inches x 3 inches long. Cube production generally only requires field (sun) drying to about 17 to 19 percent moisture (first cutting seven to eight days drying, second and third about 48 hours, and fourth cutting about five to six days--in the Boardman area). During production the cubes generate heat and must be cooled at the end of the production cycle. When used as feed, the cubes do not require the addition of ruffage. The pellets are about 1/4 inch in diameter by 1/2 inch to 1 inch long and they require significant quantities of heat for dehydration at a plant. They require about 1×10^7 BTU per ton of dried product or 2×10^6 BTU per ton of wet product in the process. When used as feed, the addition of ruffage is necessary--costing about the same as the pellets. Unfortunately, pellet production is very competitive and no new plants are being built in areas where sun drying is possible. The cube market is not as competitive.

   Two different types of dehydration plants are known. The first, a rotary flame furnace used in the United States, requires temperatures up to 1800°F, and the other, used in New Zealand, is a forced air system using a multi-layer conveyor belt with temperatures up to 250°F. In both cases, it takes about 10,000 lbs of wet alfalfa to produce 2,000 lbs of finished product.

(1) California High-Temperature Plant

A large alfalfa dehydration plant in Sacramento Valley, California, was visited in May of 1977. This plant will produce 10,000 tons of finished pellets this year (30,000 tons reported in previous years) consisting of both alfalfa and brewers grain waste from a nearby brewery. The pellets are 1/4 inch in diameter by 1 inch long produced from alfalfa at an initial moisture content of 77-82 percent and with a final moisture content of 10 percent.

A Sterns-Rogers single-pass rotary dryer is used, evaporating 60,000 to 65,000 pounds of dry product per hour with a 100 million BTU/hr natural gas burners. Thus, this requires about 0.16 therms per pound of dry product.

The main advantage of this process over sun curing is that more vitamin A and xanthrophyll (a yellow pigment present in the normal chlorophyll mixture of green plants) is retained. The latter is important in chicken and egg coloring. The xanthrophyll is retained better by high heat and rapid dehydration.

The normal operating season is from mid-March to mid-November and requires 25 people. Year-around operation is achieved by using the brewers grain waste. The buying area for the grain is 20 miles, as the plant cannot afford to haul "water" greater distances. Half of the final pellet cost is due to the dehydration cost.

(2) New Zealand Low-Temperature Plant

The system used in New Zealand at Broadlands is the result of a cooperative of 12 farms in the area, formed in 1973. Over a three-year trial period the system has proved successful and up to May, 1977, some 3,000 tons of dried alfalfa pellets have been produced.

In general, geothermal steam from a deep well bore in the Broadlands geothermal field is used. The steam is produced via a separator and used in a heat exchanger system to produce a hot air stream of approximately 275°F. The plant uses 16,000 pounds of steam per ton of pellets. A simple fixed bed, double-pass dryer is used. This dryer is made by the company and the system is unique. A continuous operation extracts approximately 8,000 pounds of moisture per hour giving approximately one ton per hour of dried alfalfa per drying unit. A larger 1-1/2 ton per hour unit is at present being developed. The system can be used for all types of green feed and grains and should also be suitable for wood chips, etc. The alfalfa pellets

produced are of high quality, strong green in color and exceed international specifications for alfalfa products. They are completely free of any type of contaminant, the material being dried in hot fresh air at all stages.

The alfalfa (lucerne) grown by farmers in the area surrounding the plant is chaffed and blown directly into trucks and delivered to and loaded onto the dryer elevator at moistures ranging between 70 and 85 percent. The drying cycle takes approximately 1/2 hour and the dried material being auger discharged into a hammer mill. It is then transported to the pellet press where it is compressed into pellets for storage and transport. Labor in the plant is minimal, two men being able to operate the entire process excluding harvesting. A plant to produce 3 tons of pellets per hour would cost $500,000 and would require 3,000 acres of alfalfa to keep the plant working at full capacity. Working 4,000 production hours per year would produce 10,000 tons of pellets.

(3) Boardman, Oregon, Low-Temperature Plant

A new method of dehydration has been used in the Boardman area in northern Oregon. This involves wilting the product in the field to remove about 25 percent moisture. The balance of the moisture is then removed by dehydration at the plant in order to retain as much of the nutrient value (vitamin A) as possible. This process requires temperatures from 180° to 250°F.

There are several reasons for fuel drying on the final product instead of complete sun wilting. Fuel drying produces a harder and heavier pellet, and retains a greater percentage of the vitamin A and xanthrophyll.

Ideally, 100,000 to 125,000 international units of vitamin A and xanthrophyll are needed; however, this can only be achieved by complete fuel drying as described in the California plant. By field wilting and then some fuel drying, they can retain a minimum of 17 percent protein and an average of 55,000 international units of vitamin A (xanthrophyll is assumed to be at about the same level as vitamin A). In addition, a bright green color is maintained that appears to improve the sellability of the product. The Japanese feel the protein guarantee is important. Complete dehydration at this time does not appear to be economical and no new plants are being built along this line.

The domestic market uses pellets for a feed mix. The main advantage with the process at Boardman is:

(a) Low fuel and temperature requirements
(b) High field moisture loss
(c) A final product with a bright green color
(d) An average of 55,000 international units of vitamin A (xanthrophyll assumed to be at the same level)
(e) A minimum of 17 percent protein

A plant of this type will produce 80 to 110 tons of pellets per eight-hour shift (ten tons per hour average--16 to 17 tons maximum). The alfalfa is purchased (or costs the company) at $45 to $55 per ton standing (at 12 percent moisture), and costs an additional $20 per ton to harvest and pellet. Of the total cost $2.50 is due to the actual drying or about 6 gallons of fuel oil per ton of alfalfa (at $.40 per gallon). This fuel usage can range from 5 to 30 gallons per ton depending upon the moisture content and the ambient conditions. The total cost of pellets is $65 to $75 per ton, of which about $5 per ton is the margin of profit. Thus any fuel savings by converting to geothermal would have a significant percentage effect on the margin of profit.

The main disadvantage with this process is that it does not produce any ruffage or fiber. Cubing will provide the necessary fiber, otherwise the pellets must be combined with ruffage for domestic use. Cost of construction of a pellet plant today is around $1 million, whereas a stationary cubing plant would cost $200,000 and a field cubing plant about $50,000.

b. Processing Steps

The more typical high-temperature plant, such as the one in California, would have the following processing steps (see Figure 33):

The alfalfa is cut in the field and chopped to lengths of 3/4 to 1-1/2 inches long (1-1/2 to 3 inches long for cubes). It is then trucked into the plant and dumped on an outdoor storage slab. From there the material is transferred by front loader to a bin and volumetric feeder. The feed rate for the entire plant is controlled at this point. A conveyor belt lifts the alfalfa to the rotary drum dryer. This dryer is 48 feet long and 10.5 feet in diameter. The drying heat is provided by a series of nozzles providing gas burning throughout the length of the drum. The drum is tilted and rotates so that the heat, air and time in the dryer produces the desired final moisture content. Typical retention time is 20 minutes. Throat temperature is 1800°F and exit temperature 235° to 240°F. The

PELLETIZED ALFALFA PROCESSING

Field   **Storage Slab**   **Volumetric Feeder**   **Conveyor**   1,800°F   240°F   **Rotary Drum Drier**

steam

Hammer Mill   **Pellet Meal Bin**   **Pellet Mill**   **Pellet Cooler**   **Fines Scalper**   **Batch Scale**   **Storage**
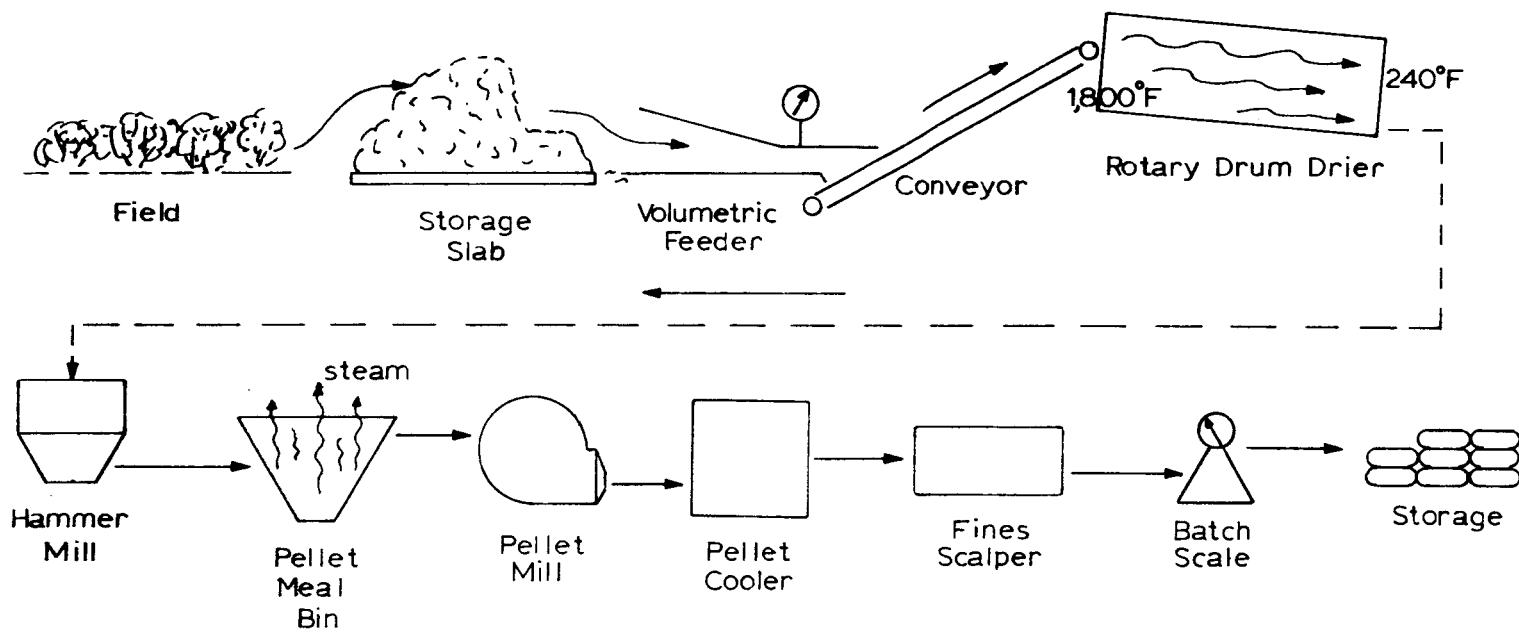
Figure 33.   Pelletized Alfalfa Processing Steps.

stack exit temperature is 215°F. The dryer is considered a single-pass, high-moisture product dryer with perforated hot plates and a detention chamber for the heavier and wetter particles. Ideal entering moisture content is 70 percent or less.

From the dryer, the alfalfa is fed to the hammer mill and the pellet meal bin. The latter is the surge point in the system. Here the material is conditioned with 17 pounds per ton of 35 psi production steam and then fed to the pellet mill pressure extruder. The steam helps in providing a uniform product and makes it easier to extrude the alfalfa through the 1/4-inch diameter holes in the circular steel plates. The material is then cooled and the fines removed in a scalper. Finally, the product is weighed on batch scales, packaged and stored.

The processing steps for the plant as described for the Boardman area are somewhat unique in the West, as it involves field wilting and a final dehydration in a rotary drum dryer. This process is also being attempted in the Midwest. Approximately 25,000 to 30,000 tons of alfalfa pellets (at 8 to 15 percent moisture) can be produced each year at 8 tons per acre (at 8 percent moisture). This assumes four to five cuttings per year. It should be pointed out that the Boardman area has extremely dry and hot summers with little or no rain, thus making field wilting practical.

The process starts with cutting and chopping the alfalfa in the field at about 70 percent initial moisture. The chopped material is then allowed to sun wilt for 24 to 48 hours to a 15 to 25 percent moisture content. This can easily be accomplished in the Boardman area due to available sun and low rainfall (if any) during the season. The Midwest is only able to wilt to about 60 percent moisture. This short field wilting time also prevents minimal damage to the next crop, as the cut material is removed before the new shoots sprout and are crushed by equipment. The field wilted material is then trucked to the plant (generally a short distance as they cannot afford to haul "water"), and stockpiled for no more than a couple of days. The chopped material is then belt-fed to a triple-pass rotary drum dryer. This dryer initially used natural gas for fuel, but this has been cut off so they now use fuel oil. The alfalfa is dried at a temperature below 250°F, as any temperature over 400°F will over-dry the product. The actual drying temperature depends upon the ambient conditions and moisture content of the alfalfa. The final pellets are checked for firmness, color, etc., as a means of adjusting the plant. Dryer temperatures can go as low as 180°F, and on some warm days the outside air can produce temperatures of 150° to 160°F without fuel. The material is moved through the dryer by a suction fan capable of producing 50,000 cfm (25 percent of this air is recycled). The retention time is about 15 to 20 minutes. The material is then fed through

a process similar to the one described for the California plant. The only other heat energy required is in the steam curing at the pellet mill--this provides a binder for the pellets. The final product is bulk stored and most of it shipped to Japan for its protein content.

c.   Geothermal Conversion

Geothermal Applications--It is estimated that approximately half (72,000 tons) of the alfalfa product in the Klamath Basin could be converted to cubes or pellets for use as dairy cattle feed. Geothermal energy might make it economical to start such a plant in the Basin, especially since more and more alfalfa is being raised. If a plant were considered for this area, one using the lower temperature heat (New Zealand- or Boardman-type) would probably be the most reasonable, as this temperature is closest to the temperature of the local resource. It is questionable whether it would be economically feasible to increase the temperature of the resource by conventional fuel to meet the temperature demands of the California-type rotary flame furnace plant.

A geothermal energy conversion design was made for the Boardman-type plant, as not enough details were available for the New Zealand-type. However, since the temperatures for both are similar, a design for the New Zealand-type using geothermal water instead of steam is possible.

Using a 200°F air drying temperature for the triple-pass dryer would require at least 220°F geothermal water. This temperature water is available in the Klamath Basin; however, wells up to 1,500 feet deep would probably be necessary.

Assuming a combination of ambient air and 25 percent recycle air at 75°F and 50,000 cubic feet per minute, 6.8×10^6 BTU/hr would be required.

If only 200°F water were available, then 180°F air could be used requiring 6.3×10^6 BTU/hr.

The following combinations of flow rates and temperatures could be used to provide the necessary energy.

T_1 (geothermal water incoming °F)	F_1 (Geothermal water flow gpm)	T_2 (Waste geothermal water temperature)
220°	500	193
220°	300	175
200°	500	175
200°	300	158

90

One well could then provide the required flow, with one injection well for the waste water. The assumed layout of the plant and wells are shown in Figure 34. Due to the high energy requirements and flow rates, a four-pass fixed water-to-air heat exchanger would be required.
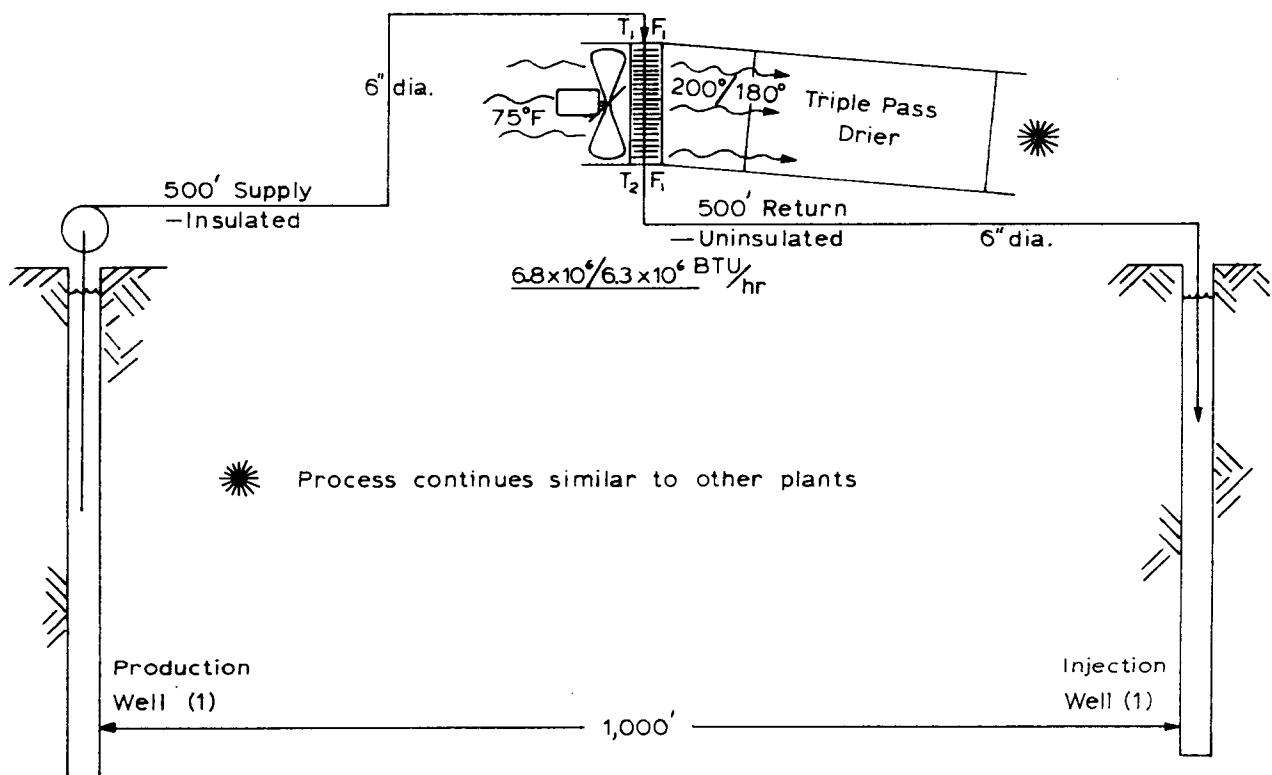
Figure 34. Alfalfa Drying Plant and Well Layout.

Figure 34. Alfalfa Drying Plant and Well Layout.

d. Economic Analysis

Economic comparison of a geothermal alfalfa drying plant as compared to a fuel oil fired plant indicates the capital investment in the heating system is about 60 times higher for geothermal.

The economic analyses of alfalfa drying does not consider investment tax credits on tangible costs, tax reduction due to write-off of tangible costs, depletion allowances, or tangible asset depreciation due to the fact that these projects involve starting new facilities which could take up to five years to pay back the additional capital investment as compared to conventional systems. Therefore, it is not known what kind of ownership or the tax structure that would be involved, nor what method of depreciation would be appropriate. Therefore, the analysis is ultraconservative and all federal tax incentives for capital investment and use of geothermal energy would increase the profit margins considerably over these figures.

The economic assessment was accomplished using a 20-year life, 9 percent per annum cost of capital and a 20-year annual equivalent cost using inflation factors on electric power costs and fuel oil costs as projected by the Oregon Department of Energy. The facility uses a low-temperature dryer of the type similar to that used by a processor in the Boardman, Oregon, area. Annual equivalent fixed costs for the geothermal system are $16,583 and require 362 hours of operation annually in order to break even with a fuel oil fired system. A plant of this type produces about 10.33 tons of product per hour and the break-even point would occur at 3,737 tons annually. Current costs per ton of product are $50/ton for materials and $20/ton harvesting and processing. Profit margin per ton of product is $5 or 7 percent. By using geothermal energy, the harvesting and process costs would be cut to less than $16/ton providing a 13.6 percent profit margin per ton of product. These calculations are based on 20-year annual equivalent costs and consider only the variable costs associated with product output. The facility at Boardman has an annual output of between 25,000 and 30,000 tons of pellets annually. After subtracting the increased annual equivalent costs of $16,364 for geothermal energy, profits would be increased by over $100,000/year for such a facility. It must be remembered that these figures are based on a 20-year life and the annual equivalent cost of fuel oil over this 20-year period. At today's prices for energy, considering a 20-year plant life, the break-even point would be 8,000 tons of product annually.

Table V indicates that a plant producing 10,000 tons annually would require five years of operation to pay back the capital investment costs of a geothermal system at 9 percent per annum. A plant similar to the Boardman facility would have a payback of about two

years. It is interesting to note that the decreasing costs of capital as project life increases, opposed to the increasing costs of maintenance inflating at 6 percent give an optimal project life of 18 years. This analysis only considers fixed annual costs and ignores the fact that due to inflation of heating fuel prices the contribution per ton of product in the 18th year is $9.19 and therefore there is considerable profit to be gained by extending the life of the system well beyond 20 years.

TABLE V
Alfalfa Pelletizing Plant

Geothermal System Costs

		20-year annual equivalent cost @ 9%
Heat exchanger (425 ft^2)	$ 15,000	
Fan (100 hp)	2,000	
Support and housing for fan and heat exchanger	5,000	
Wiring and controls	2,000	
Contingency 10%	2,400	
	$ 26,400	$ 2,892
One production well @ 1500'	40,000	
One return well @ 500'	15,000	
500' of 6" insulated pipe	8,000	
500' of 6" uninsulated pipe	2,000	
One 60-hp deep well pump	15,000	
Controls and wiring	5,000	
Contingency 10%	8,500	
	$ 96,500	$ 10,571
Geothermal annual fixed costs Maintenance	$ 2,000	$ 3,120
Geothermal hourly operation costs Pumping costs $\frac{60 \text{ hp}}{.80}$ x .7457 = 56 KWh efficiency	$0.6075/hr	$1.8529/hr
Fan operation $\frac{100 \text{ hp}}{.90}$ x .7457 = 83 KWh efficiency	$0.90055/hr	$2.7467/hr
		$4.5996/hr

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Oil-Fired System

		20-year annual equivalent cost @ 9%
Burners and supports	$ 2,000	$ 219

Annual Costs

Blower operation $\frac{75 \text{ hp}}{.90 \text{ efficiency}}$ x .7457 = 62 KWh	$0.6742/hr	$2.056/hr
Fuel oil 8.5 x 10^6 BTU/hr = 62 gal/hr = 27.032/hr		$47.7925/hr
		$49.849/hr

Total fixed annual equivalent costs geothermal

Plant conversion	$ 2,892
Wells, pumps, transmission line	10,571
Maintenance	3,120
	$ 16,583

Break-even in hours of operation

$$\text{hrs} = \frac{\$16,583 - \$219}{\$49.849 - \$4.5996} = \frac{\$16,364}{\$45.249} = 362 \text{ hours}$$

TABLE VI
Break-Even in Tons of Product Versus Project Life

Year	Annual cost of capital investment @ 9%	Maintenance inflating @ 6%	Total annual cost	Geothermal contribution per ton of product	Break-even point in tons of product	Project life in years
1978	$135,961	$2,120	$138,081	$ 2.18	63,340	1
1979	69,865	2,247	72,112	2.37	30,427	2
1980	48,552	2,382	50,934	2.81	18,126	3
1981	37,935	2,525	40,460	3.05	13,266	4
1982	30,597	2,676	33,273	3.32	10,022	5
1983	27,397	2,837	30,234	3.60	8,398	6
1984	24,419	3,007	27,426	3.90	7,032	7
1985	22,205	3,188	25,393	4.23	6,003	8
1986	20,500	3,379	23,879	4.58	5,214	9
1987	19,150	3,582	22,732	4.95	4,592	10
1988	18,060	3,797	21,857	5.36	3,953	11
1989	17,163	4,024	21,187	5.80	3,653	12
1990	16,415	4,266	20,681	6.26	3,304	13
1991	15,784	4,522	20,306	6.77	3,000	14
1992	15,247	4,793	20,040	7.31	2,741	15
1993	14,785	5,081	19,866	7.88	2,521	16
1994	14,385	5,386	19,770	8.51	2,323	17
1995	14,037	5,709	19,746	9.19	2,149	18
1996	13,732	6,051	19,783	9.91	1,996	19
1997	13,463	6,414	19,877	10.68	1,861	20

20 yr. operating life
& 9% cost of capital

Fuel Oil Fired System

Geothermal System

Geothermal Fixed Costs

Annual Equivalent Costs
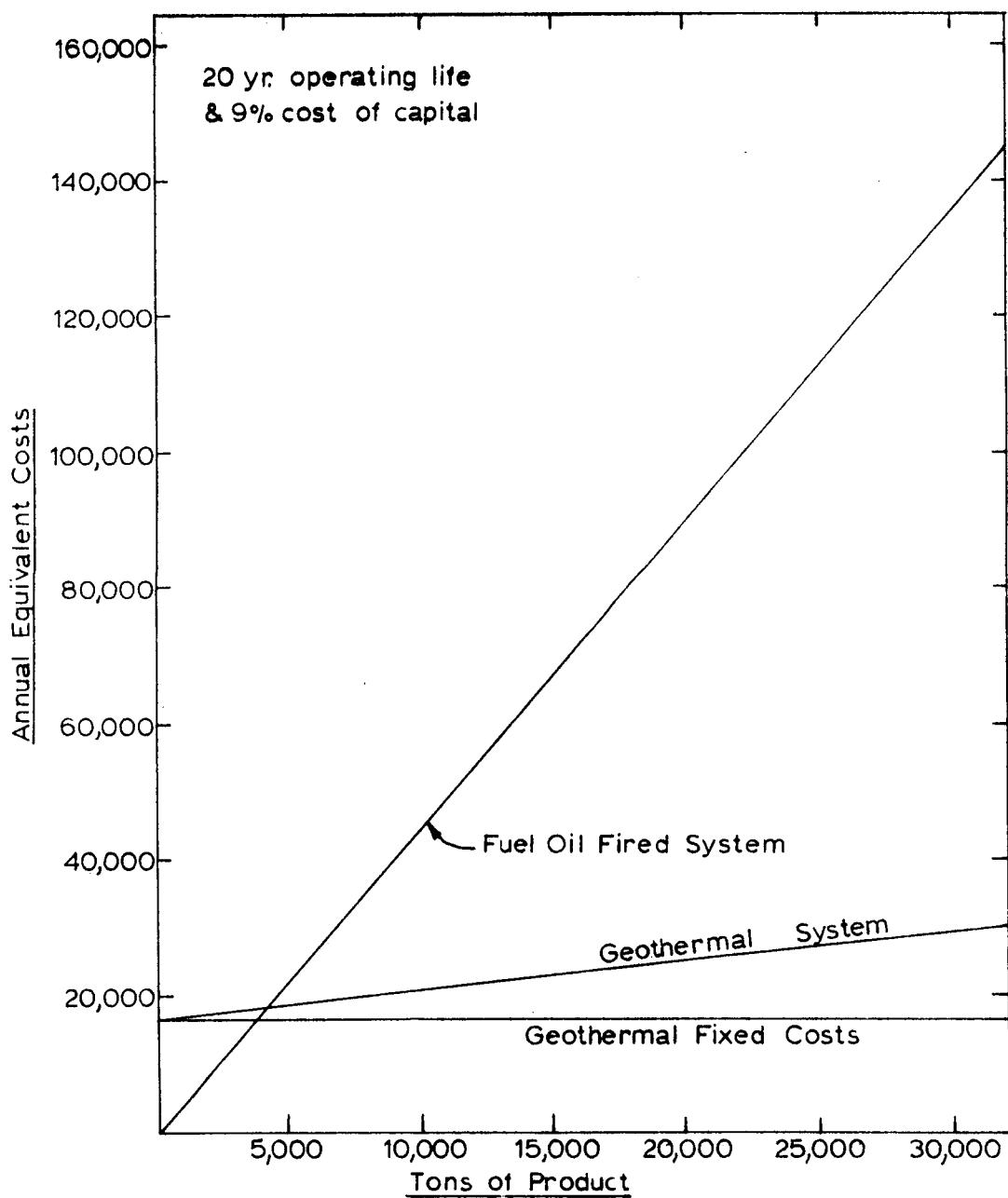
Tons of Product

Figure 35. Alfalfa Drying Plant Break-Even Analysis for Tons of
Product.
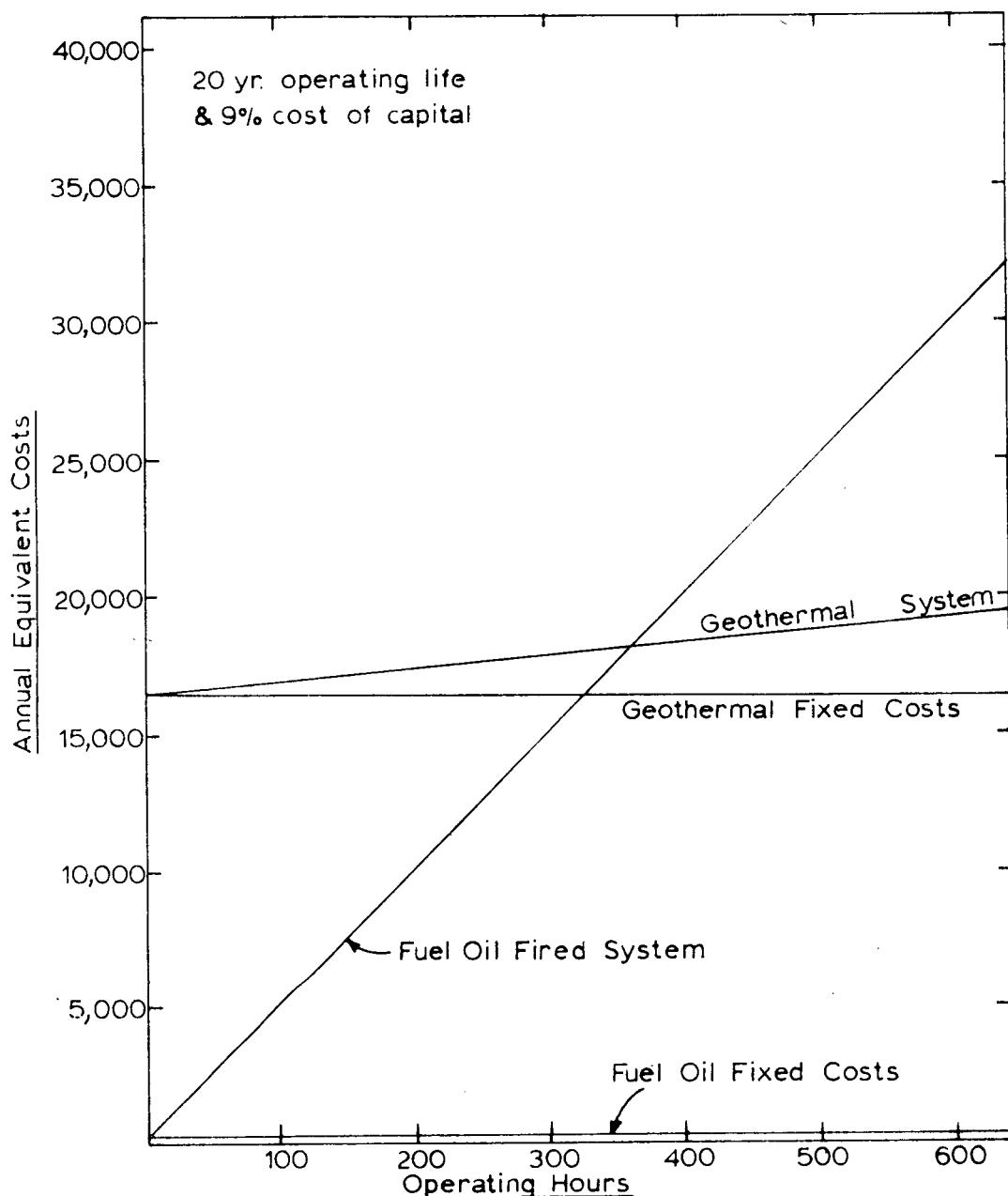
Figure 36. Alfalfa Drying Plant Break-Even Analysis for Operating Hours.

4. Western Polymer Corporation

a. General Description

The Western Starch Division of Western Polymer Corporation is located on the Oregon-California border, 21 miles south of Klamath Falls.

Twenty thousand acres of potatoes are harvested annually in the Klamath Basin producing 25 to 28 tons per acre. Nearly 10 percent of the potato crop is normally made up of substandard potatoes unsuitable for tablestock market because they are either too small, too large, misshapen, or damaged. Diversion of cull and surplus potatoes to starch factories has done much to improve the quality of tablestock and establish more orderly marketing in the potato industry.

Most of the potatoes grown in the Klamath Basin are sold on the fresh market.

The Western Polymer starch plant processes 14 tons per hour of potatoes (primarily culls) for starch extraction. The operating season or "campaign" is from September to May on an eight-hour-per-day basis.

The plant consumes 122,250 gallons of propane annually costing $42,700. Most of the fuel, 85 percent, is used for drying starch to a moisture content of 18 percent. The remaining 15 percent is used for heating offices and the plant area.

Potato starch produced nationwide is used in its various outlets in aPproximately the following proportions: paper, 60 percent; textiles, 30 percent; food, adhesives, and miscellaneous, 10 percent. Western Polymer's starch is marketed primarily to Campbell Soup and the West Coast paper industry.

b. Processing Steps

Potatoes are transported from storage to a hammer mill by means of a water flume at the rate of 14 tons per hour. The hammer mill is used to disintegrate the potato cells and liberate the starch. The skin and fiber are then separated from the starch.

Starch slurry from the hammer mill flows to centrifugal rotating sieves, which bear some resemblance to a centrifugal pump, but with slotted sieve plates in place of impeller vanes. The pulp slurry enters the rotating sieve through a central feed pipe and then flows radially outward along sieve plates. Centrifugal force drives the starch milk through the slots in the sieve plate. The coarse pulp, which cannot pass through the slots, is discharged

through a separate outlet. Several centrifugal sieves are usually employed in sieves. An advantage over ordinary screen separation is that the percentage solids content of the waste pulp from the centrifugal sieve is about three times that of pulp from the conventional screen.

The extracted pulp is dried to provide a component for livestock feed.

The final purification of starch milk is carried out by passage through a battery of cylindroconical centrifugals. These horizontal, continuous centrifugals are used to remove protein water. Settling vats are employed for removing the small quantity of remaining fine fiber and insoluble impurities that settle at the top in the so-called "brown starch" layer. The purified starch is dewatered into a cake form with a 45 percent moisture content by rotary vacuum filters.

Western Polymer uses cyclone "flash" dryers to dry the starch to an 18 percent moisture content. Predrying of the moist starch from the vacuum filter is effected in a screw conveyor through which 250°F air passes concurrently heated by direct fired propane burners. The partially dried starch then drops into a high-speed blower where it is mixed with 250°F air flowing at 15 000 cfm. The moisture-laden air and starch are separated in a cyclone dust collector. This is repeated by passing the starch through three additional blowers and cyclone separators. A fifth blower-cyclone cools the starch before bagging. The plant produces three hundred 100-pound bags during an average eight-hour shift.

c. Geothermal Applications

Geothermal energy from two sources was analyzed: the first from a 3,000-foot deep well located 15,000 feet north of the plant supplying 200°F water and the second from an existing 1,200-foot deep well located on the plant site supplying 72°F water.

A third option considered drilling the existing well to a depth of 3,000 feet to increase the water temperature to between 180° to 200°F.

Option I--200°F Geothermal Water

The water is pumped from the supply well through an asbestos cement insulated pipeline, passed through close-finned tubed heat exchange coils. The reject water (160°F) from the heat exchange coils passes through air-handling unit space heaters in the plant, then discharges to an existing cooling tank from which it is used in the process operation of the plant.

The existing dryer system (Figure 37) requires 15,000 cfm air flow
from an inlet inside the warehouse estimated at a temperature of
35°F during winter operation. The air temperature is raised to
250°F by propane burners providing 3.5 x 10^6 Btu/hr to the dryer.
A finned-tube heat exchanger installed in the warehouse would
serve as a preheater increasing the air temperature from 35° to
180°F with 200°F water flowing at 237 gpm on the water side.
This heat exchanger would provide 2.4 x 10^6 Btu/hr or 68 percent
of the energy requirements for the drying process. Reject water
at 180°F from the heat exchanger could supply the necessary space
heating for the plant, an estimated peak load of 1.0 x 10^6 Btu/hr.
This system would supply 76 percent of the thermal energy require-
ments for space and process heat.
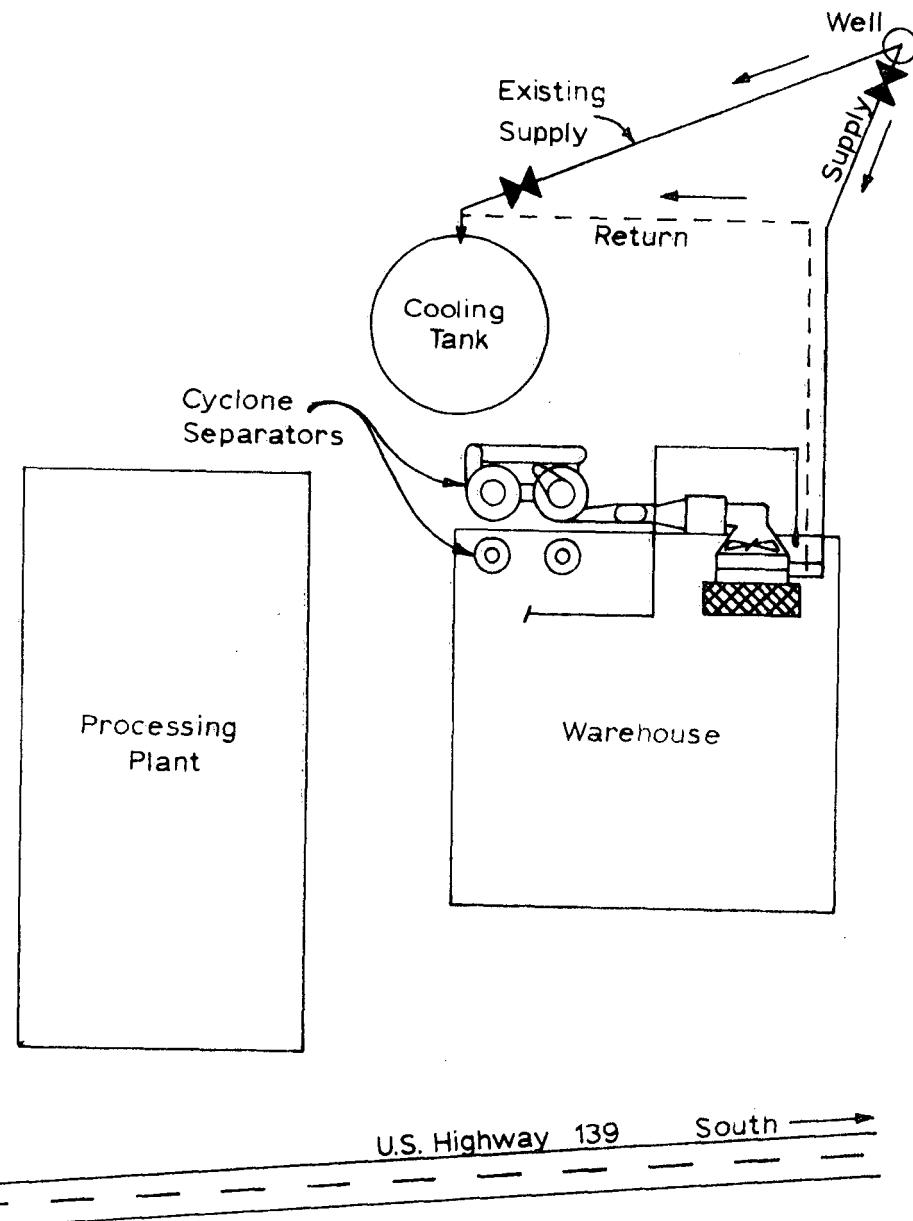
Figure 37.   Western Polymer Corporation
             layout of existing well and
             transmission lines.

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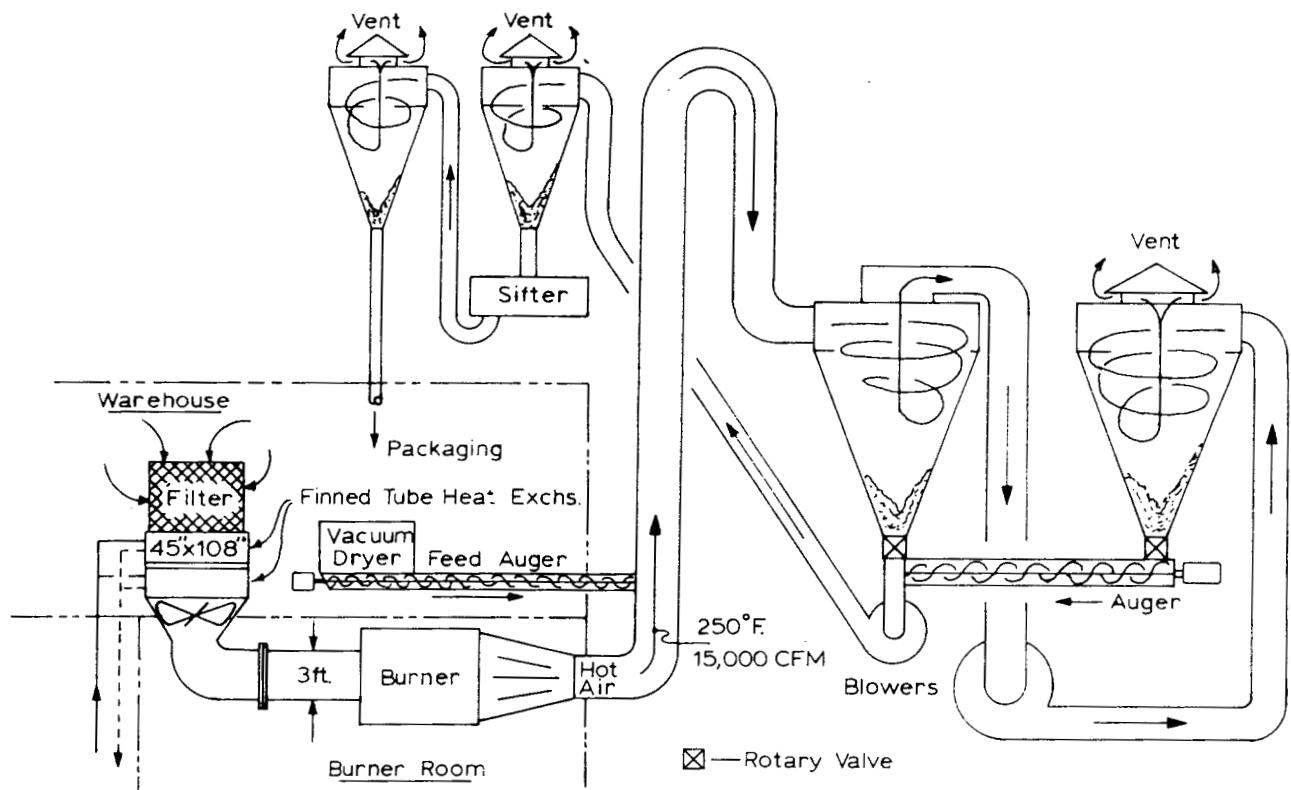
Figure 38.   Western Polymer Corporation
potato starch dryer.

Option II--72°F Existing Well

Water at 72°F is pumped to a cooling tank where it is cooled to
about 62°F before it is used in processing starch from potatoes.
Starch processing requires about 500 gpm of 62°F water in this
plant.

Piping 72°F water to finned-tube heat exchangers installed at the
air inlet of the existing dryer can serve as a preheater, heating
the air up to 68°F during winter operation. This will supply
540,000 Btu/hr, which represents about 15 percent of the heat
required for drying at peak load, or when the entering air temp-
erature is 35°F.

The existing well has a 40-hp deep-well shaft-driven pump capable
of pumping 500 gpm of 72°F geothermal water. The pump is con-
trolled by the water level in a cooling tank. This well has been
pump-tested up to 2,650 gpm.

Approximately 300 feet of asbestos cement buried pipe would be
required to supply water to the preheat coil located in the ware-
house. If insulated pipe were used, the temperature drop would
be 0.06°F, and 0.6°F for bare pipe with a flow of 270 gpm.

Option III

This option considered drilling the existing 1,200-foot well to a
depth of 3,000 feet in hopes of encountering 180° to 200°F geother-
mal water. In addition to supplying preheat for process, this sys-
tem would also provide space heating of the plant. The components
would be the same as Option I except for the 15,000-foot pipeline.

The company should consider measurements of the existing well to
determine the feasibility of this approach.

d. Economic Analysis

The economic analysis for Western Polymer Corporation was completed
by considering three options. All of the analyses were based on
200 percent declining balance depreciation with the exception of
Table IX, which was completed to show the company the advantages
of 200 percent declining balance as compared to 150 percent de-
clining balance. In all cases the inflation rate of propane was
calculated on all three options using a 9 percent cost of capital
(this is Western Polymer's method of evaluating investment
alternatives).

Option I consists of drilling a 3,000-foot well 15,000 feet from
the plant site yielding 200°F water. Option I requires a total
investment of $406,800 and would supply 76 percent of the total
energy requirements of Western Polymer. By expensing all intan-
gible costs in the first year and applying a 20 percent invest-
ment tax credit to the tangible costs, Option I provides a present
worth of only $288,867 without considering additional cost for elec-
tricity and maintenance of the geothermal system. Therefore Option
I is not economically feasible.

Option II consists of using 72°F water from an existing well
located at the plant site which would supply 15 percent of the
total energy requirements of the company. Option II requires no
intangible costs and a total tangible investment of $15,000.
Two hundred percent declining balance depreciation with ten-year
life and the 20 percent investment tax credit would allow Option
II to yield an ROI of approximately 37 percent and a four-year
payback period. In terms of ROI, or payback period, Option II
is by far the most attractive. However, it accomplishes very
little in regard to providing an independent energy source for
Western Polymer since they would still be 85 percent dependent
on propane to meet their energy needs.

In view of the fact that Option I is too costly and Option II fails to solve the energy problem, Option III was considered as a third possibility.

Option III consists of drilling the existing 1,200-foot well 1,800 additional feet to a total depth of 3,000 feet. This option assumes that 200°F water could be reached at this depth. The casing size of the existing well is suitable to allow further drilling. It was felt that 200°F water could be reached at a depth of 3,000 feet in Option I and the temperature gradient in the existing well indicates that approximately 200°F water could be reached at a depth of 3,000 feet. The primary advantage of drilling in the existing well would be to eliminate the cost of power lines and water transmission lines. The total first-year cost for Option III is $61,250 intangible costs and $63,570 tangible costs, for a total capital outlay of $124,820. The intangible costs would be expensed in the first year, providing a tax reduction of $29,400 for a net intangible cost of $31,850. An investment tax credit of $12,714 in the first year would be available on the tangible costs and with 200 percent declining balance depreciation assuming a ten-year life and 10 percent or less salvage value this option would provide a 26.5 percent ROI and a payback period of slightly less than five years. Option III appears to be the most attractive of the three options considered since it yields an attractive ROI, a shorter payback period than required by Western Polymer Corporation (five years), and reduces the consumption of propane by 76 percent. Installation of heat pumps at a later date could pick up the remaining 24 percent of the company's energy needs.

TABLE VII
WESTERN POLYMER CORPORATION
Fuel Costs

Ten-year projection of fuel costs assuming a 6 percent inflation rate and a propane inflation rate of 1-1/2 percent above the normal inflation rate. Reference: Oregon Department of Energy, "Oregon's Energy Future," First Annual Report, January 1, 1977. Beginning with a December 1977 cost of $.325 per gallon and an annual consumption of 122,251 gallons.

Year	Projected Propane Costs	Savings 76% Options I & III	Savings 15% Option II
1978	42,711.44	32,460.70	6,406.72
1979	45,914.80	34,895.25	6,887.22
1980	49,358.41	37,512.39	7,403.76
1981	53,060.29	40,325.82	7,959.04
1982	57,039.81	43,350.26	8,555.97
1983	61,317.80	46,601.53	9,197.67
1984	65,916.64	50,096.64	9,887.50
1985	70,860.38	53,853.89	10,629.06
1986	76,174.91	57,892.93	11,426.24
1987	81,888.03	62,234.90	12,283.20

TABLE VIII
Option I - 200°F Well

WESTERN POLYMER CORPORATION
Geothermal Conversion
First-Year Expenses and Investment Costs

Item	Intangible Costs	Tangible Costs
1. Drill one well	$ 92,000	$
2. Well pumps		30,000
3. Pump test	4,000	
4. Power line		5,000
5. Pipeline includes 4-in. asbestos cement insulated and trench $12/ft., 15,000 feet		180,000
6. Centrifugal booster pump		5,000
7. Heat exchanger, water to air hot water coil and fan		2,000
8. Labor to install heat exchanger		2,000
9. In-plant air handling units for space heating		15,000
10. Engineering 10% of tangible costs		23,900
11. Contingency 10% (tangible)		23,900
12. Contingency intangible 25%	24,000	
TOTAL	$120,000	$286,800

TABLE IX

Option I.   Ten-Year Cash Flow Using
a 150 Percent Declining Balance Depreciation
and 9 Percent Cost Capital

Year	Depreciation	After Tax Cash Inflow Due to Tax Credit and Depreciation	After Tax Reduction in Fuel Costs	Total Cash Inflow After Tax	Present Worth of Cash Inflow at 9% Annually
1	$ 43,020	$ 78,009.60	$16,879.56	$94,889.16	$87,054.28
2	36,567	17,552.16	18,145.53	35,697.69	30,046.03
3	31,082	14,919.36	19,506.44	34,425.78	26,583.02
4	26,419	12,681.12	20,969.43	33,650.86	23,839.12
5	22,457	10,779.36	22,542.13	33,321.35	21,656.59
6	19,088	9,162.24	24,232.79	33,395.13	19,912.42
7	16,225	7,788.00	26,050.25	33,838.24	18,510.68
8	13,791	6,619.68	28,004.02	34,623.81	17,376.52
9	11,723	5,627.04	30,104.32	35,731.14	16,451.61
10	9,964	4,782.72	32,362.15	37,144.94	15,690.43
					$277,120.70

NOTE: Total Capital investment is $349,200 after write-off
of intangible costs and the 20% tax credit.

Ten year payback is $277,120.70 exclusive of pumping and maintenance
costs for the geothermal system. Project is not economically feasible.

TABLE X

Option I. Ten-Year Cash Flow Using
a 200 Percent Declining Balance Depreciation
and 9 Percent Cost Capital

Alternative A

Year	Depreciation	After Tax Cash Inflow Due to Tax Credit and Depreciation	After Tax Reduction in Fuel Costs	Total Cash Inflow After Taxes	Present Worth of Cash Inflow at 9% Annually
1	$ 57,360	$ 84,893	$ 16,879.20	$101,772.00	$ 93,368.81
2	45,888	22,026	18,145.14	40,171.38	33,811.45
3	36,710	17,621	19,506.03	37,127.02	28,668.87
4	29,368	14,097	20,968.98	35,065.77	24,841.48
5	23,495	11,277	22,541.65	33,819.09	21,980.09
6	18,796	9,022	24,232.27	33,254.22	19,828.41
7	15,037	7,218	26,049.70	33,267.25	18,198.33
8	12,029	5,774	28,003.42	33,777.47	16,951.77
9	9,623	4,619	30,103.68	34,722.92	15,987.40
10	7,699	3,695	32,361.45	36,056.84	15,230.80

$288,867.39

NOTE: Option I does not pay back the original investment in the first
ten years exclusive of pumping and maintenance costs for the
geothermal system.

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TABLE XI
Option II - 72°F Well (Existing)

WESTERN POLYMER CORPORATION
Geothermal Conversion
First-Year Expenses and Investment Costs

Item	Tangible Costs
1. Pipeline - supply includes 4-in. asbestos cement insulated pipe and trench, $12/ft., 300 feet, and $3/ft., 200 feet noninsulated return	$ 4,500
2. Heat exchanger, water to air hot water coil and fan	5,000
3. Labor to install heat exchanger	2,000
4. Valves	1,000
5. Engineering 10% of tangible costs	1,250
6. Contingency 10% of tangible costs	1,250
TOTAL	$ 15,000

TABLE XII

Option II. Ten-Year Cash Flow Using a 200 Percent Declining Balance Depreciation and 9 Percent Cost Capital

Year	Depreciation	Cash Inflow Due to Tax Credit and Depreciation	After Tax Reduction in Fuel Costs	Total Cash Inflow After Taxes	Present Worth of Cash Inflow at 9% Annually	Present Worth
1	$ 3,000	$ 4,440	$ 6,407	$ 7,771.49	$ 7,129.81	$5,672.62
2	2,400	1,152	6,887	4,733.36	3,983.97	2,521.90
3	1,920	922	7,404	4,771.56	3,684.52	1,855.66
4	1,536	737	7,959	4,875.99	3,454.27←*	1,384.14
5	1,229	590	8,556	5,038.93	3,274.96	1,044.08
6	983	472	9,198	5,254.65	3,133.18	794.73
7	786	377	9,888	5,518.99	3,019.08	609.28
8	629	302	10,629	5,829.10	2,925.43	469.72
9	503	242	11,426	6,183.24	2,846.93	363.69
10	403	193	12,283	6,580.54	2,779.69	282.52
					$36,231.84	$14,998.35

ROI ≈ 37%

*Payback period

ROI based on 200 percent declining balance depreciation and a 15 percent reduction in fuel costs which are inflating at 7-1/2 percent per year.

TABLE XIII
Option III - Drilling Existing Well Deeper

WESTERN POLYMER CORPORATION
Geothermal Conversion
First-Year Expenses and Investment Costs

Item	Intangible Costs	Tangible Costs
1. Drill old well to 3,000 feet	$ 45,000	$
2. Well pumps		30,000
3. Pump tests	4,000	
4. Heat exchangers		2,000
5. Labor to install heat exchangers		2,000
6. In-plant air handling units for space heating		15,000
7. Transmission line - 300 feet @ 13.25/ft. 4-in. asbestos cement insulated and trenched		3,975
8. Engineering 10% of tangible cost		5,298
9. Contingency 10% of tangible cost		5,298
10. Contingency 25% of intangible cost	12,250	
TOTALS	$ 61,250	$ 63,570
Tax reduction	29,400	
Net intangible cost	$ 31,850	

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TABLE XIV
Option III. Ten-Year Cash Flow Using
a 200 Percent Declining Balance Depreciation
and 9 Percent Cost Capital

Year	A Depreciation	B Cash Inflow Due to Tax Credit and Depreciation	C Annual Savings in Reduced Fuel Costs	D Annual Electrical Costs for Well Pump	E Annual Maint. Costs for Geothermal Sys.
1	$ 12,714	$ 18,817	$ 32,460.69	$ 3,180.00	$ 3,180.00
2	10,171	4,882	34,895.25	526.22	3,370.80
3	8,137	3,906	37,512.39	570.95	3,573.05
4	6,510	3,125	40,325.82	619.48	3,787.43
5	5,208	2,500	43,350.26	672.13	4,014.68
6	4,166	2,000	46,601.52	729.27	4,255.56
7	3,333	1,600	50,096.64	791.25	4,510.89
8	2,666	1,280	53,853.89	858.51	4,781.54
9	2,133	1,024	57,892.93	931.48	5,068.44
10	1,706	819	62,234.90	1,002.09	5,372.54

Year	F Annual Savings Before Taxes	G Annual Savings After Taxes Includes 15% Depletion Allow.	H Total Annual Savings After Taxes incl. Depreciation & Investment Cr.	I Present Worth of Cash Inflow @ 9%	J Present Worth of Cash Inflow @ 26.5%
1	$28,795.70	$17,047.05	$ 35,864.05	$ 32,902.80	$ 28,351.03
2	30,998.23	18,350.95	23,232.95	19,554.71	14,518.55
3	33,368.39	19,754.09	23,660.09	18,269.93	11,688.12
4	35,918.91	21,263.99	24,388.99	17,277.78	9,524.27
5	38,663.44	22,888.76	25,388.76	16,500.95←*	7,837.70
6	41,616.70	24,637.09	26,637.09	15,882.82	6,500.45
7	44,794.49	26,518.34	28,118.34	15,381.69	5,424.45
8	48,213.83	28,542.59	29,822.59	14,966.95	4,548.01
9	51,893.01	30,720.66	31,744.66	14,616.12	3,826.98
10	55,860.27	33,069.28	33,888.28	14,314.78	3,229.57
				179,668.54	95,449.14

Rv = 6,828
ROI 26.5%
*Payback period

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TABLE XIII
Option III - Drilling Existing Well Deeper

WESTERN POLYMER CORPORATION
Geothermal Conversion
First-Year Expenses and Investment Costs

Item	Intangible Costs	Tangible Costs
1. Drill old well to 3,000 feet	$ 45,000	$
2. Well pumps		30,000
3. Pump tests	4,000	
4. Heat exchangers		2,000
5. Labor to install heat exchangers		2,000
6. In-plant air handling units for space heating		15,000
7. Transmission line - 300 feet @ 13.25/ft. 4-in. asbestos cement insulated and trenched		3,975
8. Engineering 10% of tangible cost		5,298
9. Contingency 10% of tangible cost		5,298
10. Contingency 25% of intangible cost	12,250	
TOTALS	$ 61,250	$ 63,570
Tax reduction	29,400	
Net intangible cost	$ 31,850	

TABLE XIV
Option III. Ten-Year Cash Flow Using
a 200 Percent Declining Balance Depreciation
and 9 Percent Cost Capital

Year	A Depreciation	B Cash Inflow Due to Tax Credit and Depreciation	C Annual Savings in Reduced Fuel Costs	D Annual Electrical Costs for Well Pump	E Annual Maint. Costs for Geothermal Sys.
1	$ 12,714	$ 18,817	$ 32,460.69	$ 3,180.00	$ 3,180.00
2	10,171	4,882	34,895.25	526.22	3,370.80
3	8,137	3,906	37,512.39	570.95	3,573.05
4	6,510	3,125	40,325.82	619.48	3,787.43
5	5,208	2,500	43,350.26	672.13	4,014.68
6	4,166	2,000	46,601.52	729.27	4,255.56
7	3,333	1,600	50,096.64	791.25	4,510.89
8	2,666	1,280	53,853.89	858.51	4,781.54
9	2,133	1,024	57,892.93	931.48	5,068.44
10	1,706	819	62,234.90	1,002.09	5,372.54

Year	F Annual Savings Before Taxes	G Annual Savings After Taxes Includes 15% Depletion Allow.	H Total Annual Savings After Taxes incl. Depreciation & Investment Cr.	I Present Worth of Cash Inflow @ 9%	J Present Worth of Cash Inflow @ 26.5%
1	$28,795.70	$17,047.05	$ 35,864.05	$ 32,902.80	$ 28,351.03
2	30,998.23	18,350.95	23,232.95	19,554.71	14,518.55
3	33,368.39	19,754.09	23,660.09	18,269.93	11,688.12
4	35,918.91	21,263.99	24,388.99	17,277.78	9,524.27
5	38,663.44	22,888.76	25,388.76	16,500.95←*	7,837.70
6	41,616.70	24,637.09	26,637.09	15,882.82	6,500.45
7	44,794.49	26,518.34	28,118.34	15,381.69	5,424.45
8	48,213.83	28,542.59	29,822.59	14,966.95	4,548.01
9	51,893.01	30,720.66	31,744.66	14,616.12	3,826.98
10	55,860.27	33,069.28	33,888.28	14,314.78	3,229.57
				179,668.54	95,449.14

Rv = 6,828
ROI 26.5%
*Payback period

5. Greenhouses

   a. General

   The Klamath Basin's climate is favorable for the development of
   a greenhouse industry production. Other regions of the United
   States that have major greenhouse industries and comparable
   climates are Cleveland, Ohio and Denver, Colorado. The Klamath
   Basin is comparable to Cleveland in both solar radiation and
   heating degree days; however, lags behind Denver in solar radia-
   tion (Green, 1977).

   Nearly every type of terrestrial commercial crop has been grown
   in greenhouses. Geothermal resources of temperatures above
   140°F have been used successfully for this application. Lower-
   temperature geothermally heated water can be utilized for green-
   houses than for most agribusiness industries. However, heating
   greenhouses geothermally does require large quantities of water,
   especially if lower temperatures of water are utilized. It is
   possible that some areas within the study may have insufficient
   cold water of good quality to be used for irrigation and cooling,
   or the location may be remote from a labor force or transporta-
   tion facilities. Each subarea of the Klamath Basin was evaluated
   from these criteria for determining the potential for geothermally
   heated greenhouses. (See Appendix C--Potential for Greenhouse
   Development in the Klamath Basin by Subarea.)

   A recent memorandum to Oregon's governor from the State Forestry
   Department (March 1977) stated that, "Currently, nursery produc-
   tion (to grow tree seedlings for reforestation) is considerably
   below the production capability by about 27 percent . . .."
   However, a letter from the same office to the Department of
   Economic Development (May 1977) states that, "The nursery ca-
   pacity that is in place at this time exceeds the projected demand
   by a considerable amount." These projections considered the next
   decade of Oregon's reforestation demands by the U.S. Forest Serv-
   ice and Bureau of Land Management, state and other public agencies,
   forest industry, and other private acreages. The estimated needs
   and potential supplies appear satisfactory at the present rate of
   production. About 25 percent of the total demands will be for
   container (greenhouse-grown) seedlings.

   However, the demand and supply of seedlings depends upon the
   ability of greenhouses to economically and competitively grow
   the seedlings. Most greenhouses use natural gas as their heat
   energy source. A recently published survey by the National Asso-
   ciation of Regulatory Utility Commissioners (July, 1977) stated
   that, "Residential (natural) gas prices are increasing at annual
   rates ranging from 20 percent to as high as 40 percent."

Commercial gas rates have increased correspondingly. Furthermore, most greenhouse industries have been placed on interruptable supplies which could damage or destroy a large portion of Oregon's 41 million containerized seedling crops for any year. These combinations of events where the forest industry is dependent upon greenhouse-grown seedlings and the spiraling costs of undependable fossil fuel supplies, are the major reasons for the accelerated interests in geothermal heated greenhouses to grow the product.

b. Geothermal Heating System

The greenhouse business benefits from the size or scale of operation. For purposes of this study a one-acre unit house is used as the basis for a 15-acre operation.

Greenhouse heating and construction costs are based on a fiberglass furrow-connected gable structure covering 43,200 ft^2 of floor area. Well depths and geothermal water temperature will vary depending on the selected site as indicated in the resource assessment section of this report. For purposes of economic analysis, 200°F geothermal waters at a depth of 1,500 feet were assumed. The chemical properties of waters in areas noted should not create excessive scaling or corrosion problems in heating equipment (fan coils and pipes) or pumps. Similar waters have been used directly for many years in Klamath Falls.

Greenhouse Design — One Acre Unit
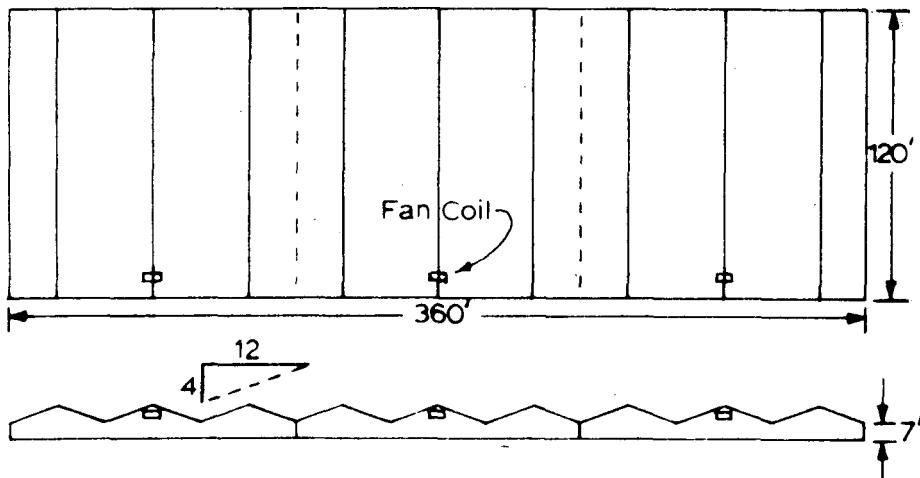
1. Size - 120' x 360' = 43,200 ft^2.

2. Outside design temperature = -10°F.

3. Design temperature inside greenhouse = 70°F.

4. Building orientation--furrow-connected structure with ridges running north-south.

5. Cooling--single ceiling vent along each ridge and wall vents.

6. Heating--combination fan coils and horizontal pipes located on walls and under benches.

7. Heat loss from corrugated fiberglass furrow-connected gabled house--increase exposed surface by 18.8 percent (Green, 1977).

	Flat surface	Corrugated surface
Exposed roof area -	45,530 ft^2	54,089 ft^2
Exposed wall area -	9,600 ft^2	11,405 ft^2
TOTAL	55,130 ft^2	65,494 ft^2

$q = UA\Delta T$

Roof: $q = 1.22 \dfrac{Btu}{hr - ft^2 - °F} \times 54,089 \text{ ft}^2 \times 65°F$

$= 4.29 \times 10^6 \text{ Btu/hr}$

Walls: $q = 1.13 \dfrac{Btu}{hr - ft^2 - °F} \times 11,405 \text{ ft}^2 \times 65°F$

$= .84 \times 10^6 \text{ Btu/hr}$

Total heat loss = 5.13 x 10^6 Btu/hr.

8. Annual heat loss $= \dfrac{6300 \text{ deg day}}{yr} \times \dfrac{1}{65 \text{ deg}} \times \dfrac{24 \text{ hr}}{day} \times 5.13 \times 10^6 \dfrac{Btu}{hr}$

9. Annual heat loss (15 acres) = 1,790,000 therms/yr.

Heating System Design

Free convection from horizontal pipes is the method widely used for heating greenhouses with geothermal waters in Iceland and Europe (see Figure 39) and is the basis for the heating pipe network design used in this study.
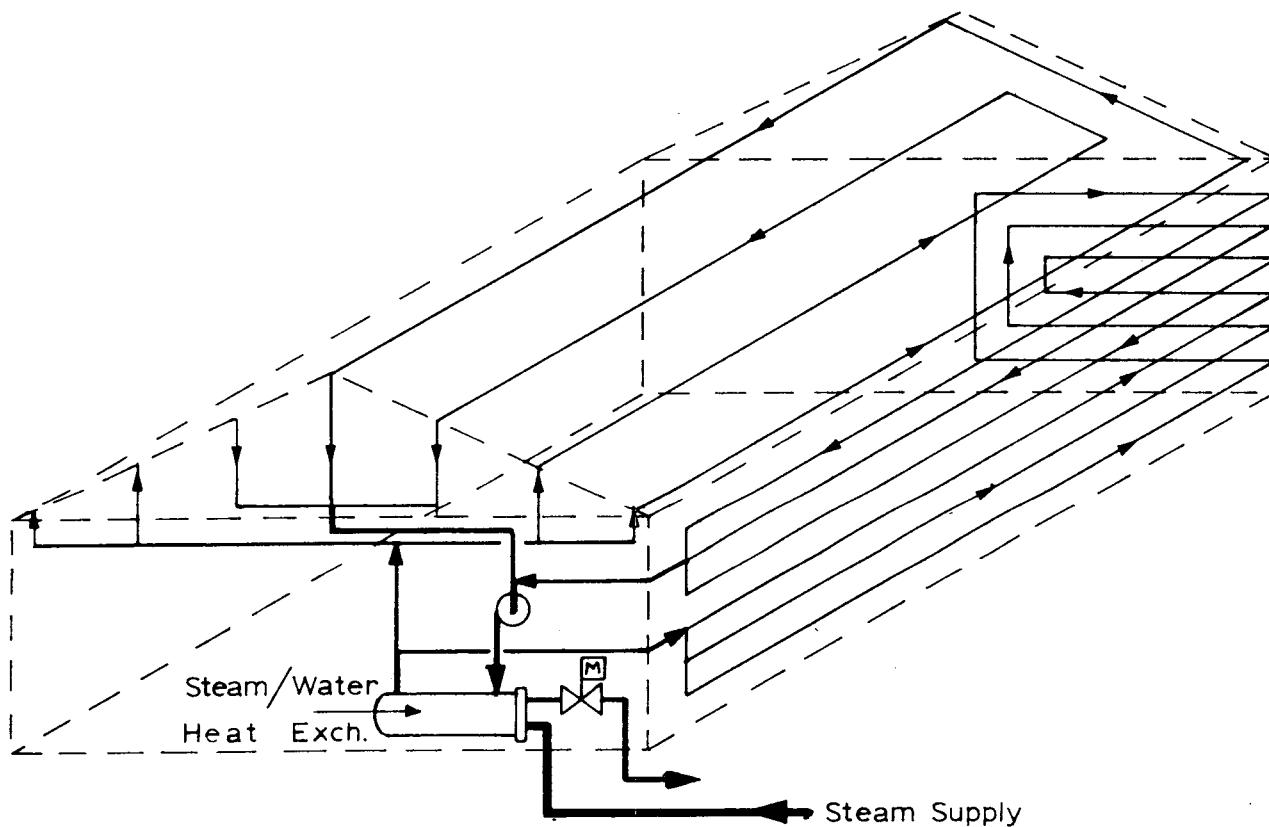
Figure 39. Heating pipe network for greenhouse
             at Hveragerdi, Iceland.

The system considered for this study consists of a fan coil connected in series with a network of horizontal pipes installed on outside walls and under benches, as shown in Figure 40. Three of these systems are required for each one-acre house.
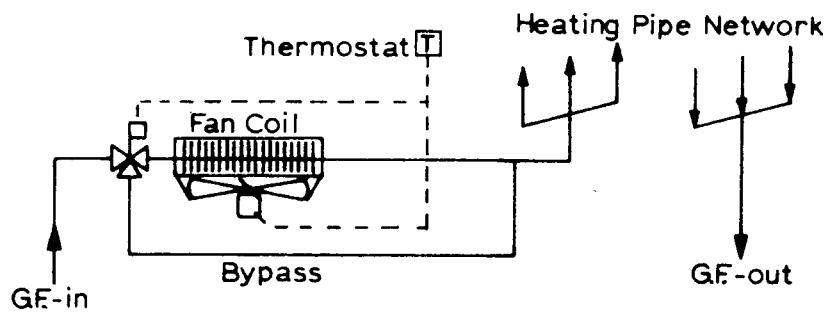
Figure 40. Unit Heating System Design (three per house)

Heat transfer per unit length for horizontal pipe due to free convection and radiation is given by the following equation (McAdams, 1954):

$$q = (hc + hr)A \Delta T$$

Nested horizontal pipes mounted on outside walls prevent downdrafts caused by the cold walls and radiation transmitted through fiberglass is negligible due to the long wavelength produced by the low-temperature pipes.

Bare Pipe Convection

Heat transfer from the network of two-inch horizontal pipes for a one-acre greenhouse:

$$q = 165 \text{ Btu/hr-ft} \times 19,000 \text{ ft} = 3,135,000 \text{ Btu/hr}$$

The pipe network, operating independently of the fan coils, supplied with 200°F geothermal waters would heat the house down to an ambient temperature of 15°F or provide for all but 10 percent of the annual heating requirements. Three fan coils, each rated at 655,000 Btu/hr, would be required to heat the greenhouse on the coldest winter day, with reject water from each fan coil going through the network of heating pipes. A thermostat located inside the house would control the water flow through the house by means of a motorized valve and the motor of the fan coil.

Finned-Tube Convectors

Heat transfer from a two-row network of two-inch finned-tube convectors (4-1/2-inch fins, 33/ft) with a supply temperature of 180°F is rated at 1570 Btu/hr-ft. The heat transfer from convectors mounted on outside walls is:

$$q = 1570 \text{ Btu/hr-ft} \times 1,440 \text{ ft} = 2,261,000 \text{ Btu/hr}$$

Additionally, three fan coils rated at 956,000 Btu/hr each would be required to heat the greenhouse on the coldest winter day.

Distribution System

For a 15-acre complex, a double-pipe system is used to circulate water to a 60,000-gallon storage tank. The supply water to the greenhouses is maintained at 180°F by mixing entering 200°F water from the wells and the return water from the houses. When the return water temperature drops below 90°F, the valve to the return well opens and closes at a preset higher temperature, and water is disposed of by means of the injection well. This

double-pipe system illustrated in Figure 41 reduces the number of production wells required by extracting 110 Btu per pound of water. Geothermal water demand on the coldest winter day is 93 gpm for a one-acre house.
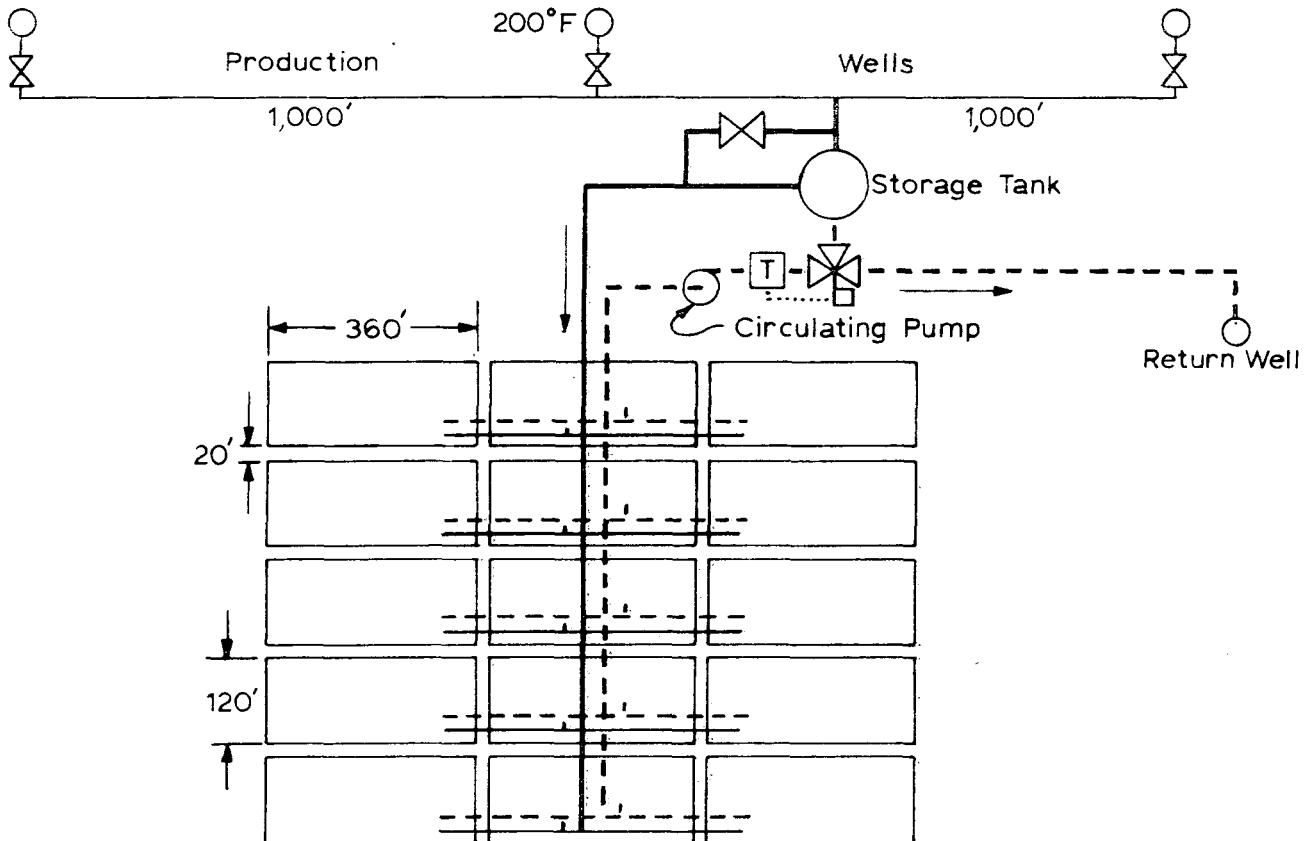
Figure 41. Fifteen-acre greenhouse complex.

The 15-acre complex would require 1,395 gpm with the water flowing directly through the system to the injection well.

For purposes of this study it is assumed each well is drilled to an average depth of 1,500 feet and is capable of producing 500 to 600 gpm of 200°F geothermal waters. Three production wells and one return well would be required for a 15-acre greenhouse complex. Deep-well shaft-driven turbine pumps (50 hp), controlled by the water level in the storage tank, are installed at each well.

Insulated asbestos cement pipe buried to a depth of three feet is used for the transmission line. Bare asbestos cement supply and return pipe buried under the houses are used for the distribution system.

c. Economic Analysis

The economic analysis for greenhouses was accomplished using a
15-acre greenhouse complex. This was considered to be an optimal
size since it requires three production wells and a return well.
It was estimated that the production wells would operate on an
average of 12 hours per day throughout the year. It was felt
that during the three coldest months of the year nearly 100 per-
cent of operation from all wells would be required during the
night or periods of heavy overcast and during the three warmest
months of the year production would be practically zero. The
remaining six months would require maintaining of temperatures
overnight which could be done with minimal production and the
use of the recirculating storage tank. While the annual cost
per one-acre greenhouse heated by natural gas would be a linear
function and could simply be multiplied by the number of one-
acre greenhouses, it would not be economically feasible to drill
a production and return well for one acre of geothermal green-
houses. Since one production well could serve five acres of
greenhouses and three production wells could serve 15 acres of
greenhouses with the requirement of only a single return well,
the annual costs of geothermal greenhouses are reduced drasti-
cally by economies of scale.

TABLE XV

INVESTMENT COSTS FOR A 15-ACRE GREENHOUSE COMPLEX

		Natural Gas	Geothermal
1.	Land	$ 15,000	$ 15,000
2.	15 houses - 43,200 ft^2 @ $2.75/ft^2	1,782,000	1,782,000
3.	Outfitting house - $1/ft^2	648,000	648,000
4.	Heating and cooling equipment	635,000*	687,000
5.	Engineering @ 10%	308,000	313,200
6.	Contingency @ 10%	308,000	313,200
	Total investment	$3,696,000	$3,758,400
	Depreciable investment	$3,681,000	$3,743,400

TABLE XVI

GREENHOUSE CONVERSION COSTS FOR GEOTHERMAL ENERGY

	Energy Costs	Intangible	Tangible
1.	3 wells - 1,500 feet deep @ $38,000/well	$ 114,000	$
	1 return well	38,000	
2.	3 deep-well turbine pumps - 50 hp		60,000
3.	Pump tests	4,000	
4.	Power line		15,000
5.	Pipeline (includes installation)		74,000
6.	Circulating pump - 35 hp		5,000
7.	Storage tank - 60,000-gallon		15,000
8.	Engineering @ 10% (tangible costs)		16,900
9.	Contingency @ 10% (tangible costs)		16,900
10.	Contingency @ 25% (intangible costs)	39,000	
	These costs will be expensed in the first year	$ 195,000	
	These costs yield a 20% investment tax credit		$ 202,800

TABLE XVII

GREENHOUSE ANNUAL OPERATING AND MAINTENANCE COSTS

The following costs are estimated to increase by 6 percent per year.

	Natural Gas	Geothermal
House maintenance - $445/house*	$ 6,650	$ 6,650
Heating and cooling maintenance - $48/acre-house	720	720
Pump and well maintenance		6,000
Cooling pad and duct replacement - $567/year/acre-house	8,505	8,505
Insurance - $2,000/acre-house	30,000	30,000
TOTAL	$ 45,875	$ 51,875

*In evaluating the annual cost of natural gas greenhouses and estimating in-house maintenance, electricity, insurance, property taxes, cooling pad, and duct replacement, and heating and cooling maintenance, data were extrapolated from Klamath Basin - A Potential Greenhouse Development Site, Agricultural Experiment Station, Oregon State University, Corvallis, August 1977.

TABLE XVIII
TWENTY-YEAR PROJECTION OF ANNUAL ENERGY COSTS
FOR A 15-ACRE GREENHOUSE COMPLEX

Year	Natural gas 13,222 MBtu/ 1 acre/yr* @ $2.521/MBtu	Geothermal electric power 446,646 KWh/yr	Electric power costs for either system	Annual savings of geothermal system
1978	$ 500,009	$ 3,890	$2260	$ 496,119
1979	556,010	4,221	2450	551,789
1980	618,283	4,580	2660	613,703
1981	687,531	4,969	2890	682,256
1982	764,534	5,392	3130	759,142
1983	850,162	5,850	3400	844,312
1984	945,380	6,347	3690	939,033
1985	1,051,263	6,887	4000	1,044,376
1986	1,169,004	7,472	4340	1,161,532
1987	1,256,680	8,038	4670	1,248,642
1988	1,350,931	8,648	5020	1,342,283
1989	1,452,250	9,303	5410	1,442,947
1990	1,561,169	10,008	5810	1,551,161
1991	1,678,257	10,767	6260	1,667,490
1992	1,804,126	11,583	6730	1,792,543
1993	1,939,436	12,461	7240	1,926,975
1994	2,084,893	13,405	7790	2,071,488
1995	2,241,260	14,422	8380	2,226,838
1996	2,409,355	15,515	9010	2,393,840
1997	2,590,056	16,690	9700	2,573,366

*Heating efficiency for natural gas is 90 percent.

The total annual equivalent costs of a 15-acre greenhouse complex (see Table XXI) were calculated using a 9 percent per annum cost of capital assuming a 20-year life, as follows:

1) First-year investment tax credit was discounted at 9 percent and subtracted from the total capital investment for the 15-acre greenhouse complex.

2) A 20 percent tax investment credit was discounted at 9 percent and subtracted from the tangible investment in the geothermal system.

3) The tangible costs associated with the geothermal system were considered to be expenses in the first year, reducing federal income taxes by 48 percent, and the resulting reduced taxes were discounted at 9 percent and subtracted from the total tangible investment.

4) The annual cost of insurance in house maintenance, heating and cooling system maintenance, well and pump maintenance, was inflated at a rate of 6 percent per annum, which is assumed to be the economic inflation rate.

5) Property taxes were inflated at a rate of .1 percent per annum. Annual electrical energy costs were inflated at a rate of 8-1/2 percent per annum through 1986, and at 7.58 percent per annum thereafter. These inflation rates for electricity were obtained from the Oregon Department of Energy.

The annual equivalent costs for a 15-acre complex heated with natural gas were calculated in the same manner except that there were no intangible costs, and inflation rates for industrial natural gas were assumed to be 11.2 percent per annum through 1986 and 7-1/2 percent per annum thereafter.

TABLE XIX
EQUIVALENT ANNUAL COST FOR A 15-ACRE GREENHOUSE COMPLEX.
ASSUME A 20-YEAR LIFE AND A 9 PERCENT PER ANNUM COST OF CAPITAL.

	Natural Gas		Geothermal	
	Present worth	Annual equivalent	Present worth	Annual equivalent
Capital investment in 15-acre complex and equipment less 10% investment tax credit discounted at 9%	$3,696,000 - 339,083 $3,356,917	$ 367,738	$3,758,400 - 344,807 $3,413,593	$ 373,947
Tangible energy investment less 20% investment tax credit discounted at 9%	-0-	-0-	$ 202,800 - 37,211 $ 165,589	$ 18,140
Intangible energy investment expensed in first year less reduced federal taxes discounted at 9% (assumes 48% federal taxes)	-0-	-0-	$ 195,000 - 85,872 $ 109,128	$ 11,955
TOTAL FIRST-YEAR COSTS	$3,356,917		$3,688,310	
Annual maintenance and insurance (inflation 6% per annum)		$ 71,654		$ 81,026
Property taxes (inflation .1% per annum)		51,835		51,835
Electrical power costs (inflation 8.5% through 1986 and 7.58% thereafter)		4,240		7,713
Natural gas annual costs (inflation 11.2% through 1986 and 7.5% thereafter)		1,087,967		-0-
TOTAL ANNUAL EQUIVALENT COST		$1,579,618		$ 544,616

TABLE XX
ADDITIONAL CAPITAL INVESTMENT REQUIRED
FOR A GEOTHERMAL COMPLEX

$331,393

Year	Annual savings	Discounted cash flow before taxes 150%	160%
1	$ 496,119 (note)	$198,448	$190,816
2	551,789	88,286	81,626
3	613,703	39,278	34,917
4	682,256	17,466*	14,930
5	759,142		5,389
6	844,312		2,733*
7	939,033		
8	1,044,376		
9	1,161,532		
10	1,248,642		
11	1,342,283		
12	1,442,947		
		$343,478	$331,410

*Payback period

NOTE: Investment pays back in one year at 49.7 percent

In calculating an ROI, it is only necessary to consider the cost
differences between the conventional and geothermal heating system.
Additional capital investment of $331,393 is required for the geo-
thermal system. Examining the energy costs in Table XX, it becomes
obvious that the ROI is in excess of 100 percent. When using the
equivalent annual cost formula with projected energy costs, those
costs that are projected into the future ten years or more become
insignificant with an ROI in excess of 100 percent. For example,
the costs of natural gas from 1987 through 1997 begin with a rela-
tive high annual amount of $1,256,680 annually and inflate at a
rate of 7.5 percent a year. However, when calculated at a rate of
return of 160 percent, these costs have a present value of only
$89. Annual costs of $10,000 or less approach zero in present
value and become insignificant. The ROI was calculated at 160 per-
cent and gave a payback in six years, indicating the ROI is higher
than 160 percent. A ROI calculation was done for 165 percent and
yielded no payback, indicating the ROI was slightly higher than
160 percent; therefore, the ROI is assumed to be approximately
162 percent.

C. Western Snake River Basin Assessment

1. Background

Some understanding of the physical geography of the basin is necessary
in order to realize the agricultural and agribusiness potential of the
area. The benchlands of the Oregon portion of the Snake River Basin
were formed during a period of intensive volcanic activity in south-
western Idaho and eastern Oregon. Lava flows filled the stream val-
leys, including the Snake River, damming them and impounding large
lakes. Several thousand feet of sediments were deposited in the lakes,
which subsequently were drained by streams eroding through the basalt
dams. Wind transported sediments and alluvial materials mantle exten-
sive portions of the area and have matured into excellent agricultural
sails which produce high yield crops where irrigation water is available.

The climate can be considered as semiarid, experiencing hot dry summers,
cold winters and moderate spring and fall temperatures. The average
temperatures for the Vale, Ontario, Nyssa area is about 10°C (50°F),
with an average annual precipitation of 8 to 10 inches. The frost-free
growing period in the agriculturally extensive area is 150 to 180 days
per year.

Agriculture is the major base of the area's economy and food processing
is the only major manufacturing activity. The major food processing
crops produced are potatoes and sugar beets with minor crops of sweet
corn and onions. In 1975, 10,200 acres of potatoes, 5,400 acres of
sweet corn and 5,500 acres of onions were grown in Malheur County.
Most of the onions are sold to the fresh vegetable market.

The processing plants have historically depended primarily on natural gas for their energy supplies but are now in the process of changing to oil. One plant has already converted to using coal. The agribusiness industry consumes considerable quantities of relatively low-temperature heat in the range of 140° to 300°F (Reistad, 1975). A major savings in fossil fuels could be achieved if food processing industries in the region could utilize geothermally heated waters for a portion of these energy requirements.

The geothermally heated greenhouse industry in the basin has been limited to three greenhouses at Vale which have been in production for more than 20 years. Their major crop has been foliage, flowering, and bedding plants. While no future expansion of this operation is anticipated, a five-acre greenhouse-mushroom growing complex is beginning construction adjacent to the present greenhouses.

Geothermal energy from the basin's reservoir could be used to reduce the wide fluctuations in agricultural incomes experienced in most farming areas. Greenhouses could be individually and/or cooperatively owned and managed by farm operators. Such activities would extend the season and produce crops not presently competitive in the area. A dehydrator could utilize other crops that are not presently grown on basin farms. Specifications for the Klamath Basin greenhouses and dehydrator presented earlier in this report could be utilized by using the cost charts in the introduction of this section to include the additional expenditures of deeper wells than in the Klamath Basin.

Comprehensive Land Use Plans for Malheur County, Oregon address the agricultural economy of the area. County planners anticipate changes which can be made in their long-range plans when geothermal energy resources can expand and stabilize the economic base for their area's residents.

2. The Amalgamated Sugar Company, Nyssa, Oregon

    a. General Description

    The Nyssa District of the Amalgamated Sugar Company is situated on the Oregon-Idaho border near the Snake River in one of the nation's outstanding agriculture areas.

    The Nyssa sugar factory--Oregon's only sugar processing plant-- was built in 1938 and is the seventh largest beet sugar processing plant in the United States. This factory can process 6,300 tons of sugar beets every 24 hours. Approximately 200 tons per day of molasses is also worked by means of the Steffen process. The campaign usually starts October 10 and runs 120 to 125 days. During the campaign the company employs 450 people on a three shift per day basis. Off season, 160 full-time employees repair plant equipment and ship stored sugar and by-products.

When the plant is operating, 615 tons of coal are burned in the boilers per day. A total of 2.02×10^{12} Btu of coal and 1.15×10^{11} Btu of natural gas were used during the 1976 season. The plant converted from burning natural gas as its main fuel supply to coal in the early 1970s. The plant has electric generators that produce 5000 kw; in addition 3000 kw are purchased.

Steam is supplied from five boilers at 68.4 lb/sec (245 psia to 3000 and 541-kw generators and 420 psia to the 1500-kw generator) to the generators. Exhaust steam at about 50 psia pressure is used primarily for process in the first-effect evaporator. The company is trying to reduce energy consumption by 20 percent.

White Satin sugar processed at Nyssa is packaged in 25-, 50-, and 100-pound bags. Nyssa's sugar warehouse, the company's largest, can hold over 33,500 tons of bagged sugar for distribution to customers. Huge silos can hold an additional 43,500 tons of bulk sugar shipped to industrial customers and consumer markets.

The company's White Satin sugar is sold primarily to bakeries, canneries, bottlers, and other food processors in Utah, Idaho, Oregon, and Washington, as well as in eight midwest states.

The company's dried molasses beet pulp sales are coordinated through offices at Nyssa. This high protein livestock feed is sold to farmers and livestock feeders throughout six western states and three foreign countries.

b. Processing Stages

Preparation of sugar beets for processing is the step between harvesting and slicing operations. These steps include: receiving at the factory site; dirt and trash removal; short-term storage; beet flow control; final trash removal and final cleaning; and elevating to the factory slicers. The above steps to not use thermal energy.

In the following stages thermal energy is involved in the process. The processes may be conveniently separated into six stages: 1) diffusion; 2) juice purification; 3) evaporation; 4) crystallization, 5) dried pulp manufacture; and 6) recovery of sugar from molasses. The first three stages comprise the beet end of the factory, and the fourth stage the sugar end.

The composite flow sheet (Figure 42) and the following descriptions for the Steffen process, used at the Nyssa plant, will help in understanding the beet sugar manufacturing process and its energy requirements.
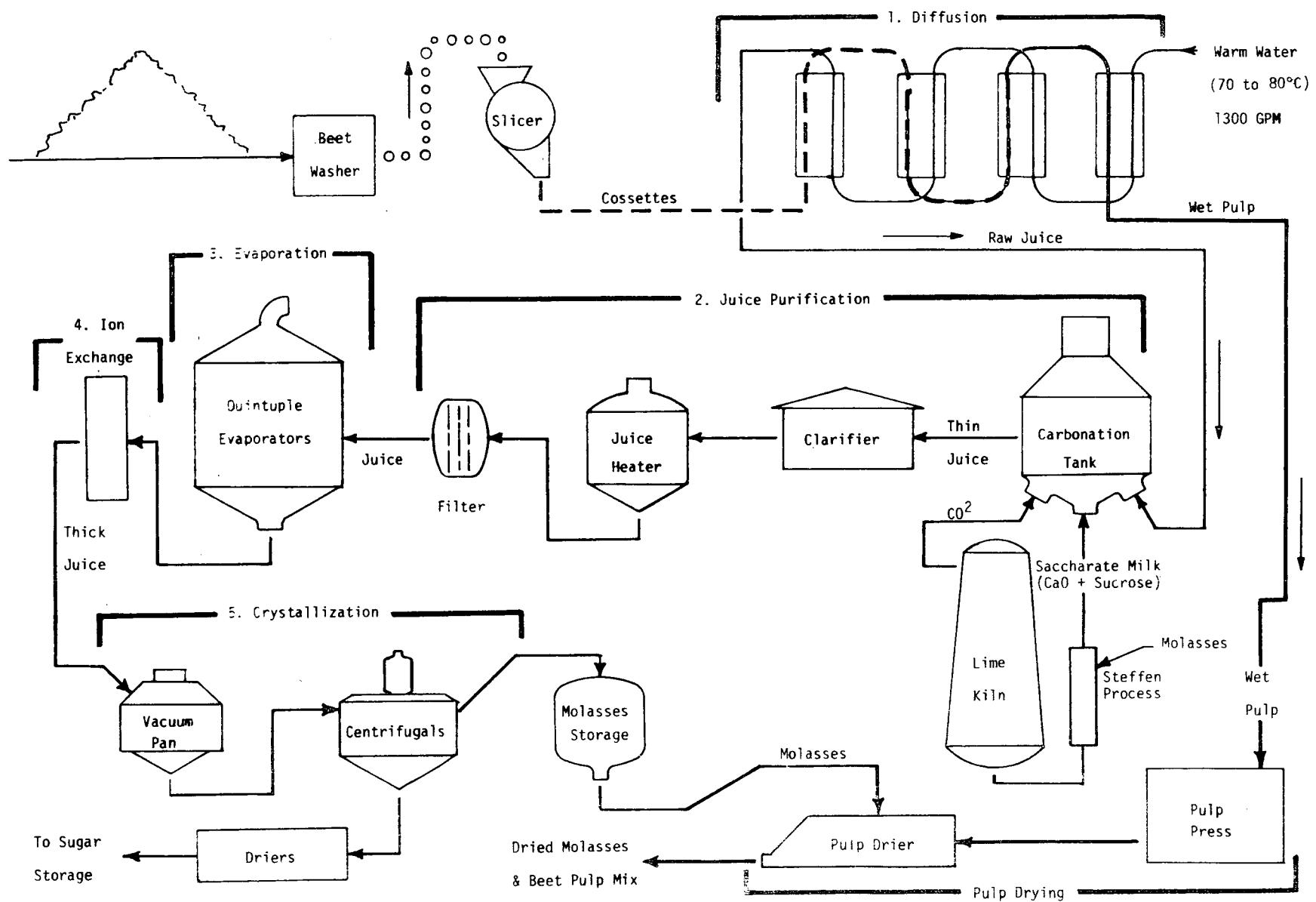
Figure 42.   Processing stages--composite flow sheet.

1) Diffusion

The diffusers separate from the long thin strips (cossettes) of sliced beets the pulp and raw juice. Continuous diffusers are used at the Nyssa plant. To start the process 78,300 gpm of makeup water enters and percolates by gravity through the cossette mass, leaching out sugar as it proceeds countercurrent to the cossettes. The temperature is raised to between 158° and 176°F, for better extraction, by steam-heated jackets surrounding the trough. The rate of diffusion increases directly with temperature. The sugar loss in exhausted pulp is proportional to the product of time, temperature, draft, and cossette size. Higher temperatures in the diffuser make it possible either to lower the draft, to increase the size of cossettes, or to shorten the contact time between juice and cossettes without increasing sugar loss. The draft is the ratio of the weight of diffusion juice drawn from the diffuser to the weight of cossettes introduced expressed as percent. Drafts vary between 100 and 150 percent.

The steam required for the diffusers comes from the evaporator juice second vapor.

The sugar-depleted cossettes leaving the diffuser are known as pulp and are transferred to the pulp press and dryer. Sugar-enriched juice is next introduced to the juice purification process. The diffusion juice contains between 10 and 15 percent sugar, which is about 98 percent of the sugar which was in the beets when sliced.

2) Juice Purification

It is necessary to purify the juice since it contains nonsugar impurities. The nonsugar impurities in both true and colloidal solution make it very difficult to concentrate the diffusion juice, or to crystallize pure sugar from it. Impurities are removed by introducing lime in the form of a slurry of calcium saccharates obtained from the Steffen process for extracting sugar from molasses. The CO_2 bubbles are passed through the mixture to precipitate lime as very small calcium carbonate crystals. As the crystals precipitate the impurities coagulate and adher to the calcium carbonate crystals and can be settled out as a thickener in the clarifier. The purpose of a second carbonation is the removal of lime remaining in solution. Second carbonation is at a lower pH; the precipitated calcium carbonate is removed by filtration. At this point the juice is known as thin juice. Preporatory and during purification, juice is heated from 148° to 194°F plus the thermal energy used at lime kilns to produce CaO and CO_2.

Thin juice is heated to 239°F and transported to the evaporators.

3) Evaporation

Heat is required to evaporate water from the beet juices.
This heat is supplied to the first-effect evaporator as
steam from the electric generator turbine exhausts at 50
psia absolute. Thermal energy for this process consumes
about 80 percent of the total energy produced at the plant.

Water evaporated from the beet juices in the first-effect
evaporator leaves as vapor which is subsequently used in
succeeding evaporator stages and other processes in the plant.

Multiple-effect evaporators are used with five individual
bodies or effects, as shown on Figures 43 and 43A; turbine
exhaust plus reduced pressure super-heated live steam makeup
(77.2 lb/sec total) steam at 50 psia is piped to the first-
effect steam chest. On condensing, this steam gives most of
its heat to the juice in the first effect, 1A and 1B; the
transfer of heat causes the juice to boil. Vapor from the
boiling first-effect juice passes through the evaporator
dome and is piped into the vapor chest of the second-effect
evaporators (2A, 2B, and 2C), and to other processes.

First-effect vapor in the second-effect vapor chest gives
most of its heat to the juice in the second effect, and so
produces second-effect vapor. This process continues down
through evaporators 3, 4, and 5, until the vapor from the
last effect is led to a condenser. This condenser maintains
the last vapor below atmospheric pressure and consequently
at a low temperature. Thus, each evaporator effect acts
as a condenser for the preceeding effect. Each succeeding
vapor pressure, and of course temperature, is proportionately
lower with the lowest vapor pressure in the last effect under
control by the barometric condenser.

One pound of steam admitted to the first-effect steam chest
evaporates approximately one pound of water from the juice
in the effect. One pound of the first vapor thus formed, when
admitted to the second-effect steam chest, will evaporate one
pound of water from the juice in the second effect. Conse-
quently, one pound of steam admitted to the first-effect evapo-
rator will evaporate approximately five pounds of water in the
quintuple-effect evaporator. Evaporation comes from two
sources: juice "flash" and condensation of steam or vapor
in the chest.

High-pressure steam from the boilers at 255 psia is expanded
to exhaust steam pressure, either through turbines or reducing
valves, and is used in the first-effect evaporator only. All
other factory heating uses vapor from the following effects:
diffusion juice with third and then second vapor, juice after
carbonation with second vapor, and thin juice on its way to
the first effect with second vapor then first vapor.

a. steam chest (calandria)   d. vapor condensate out   g. to diffusers, heaters & pans
b. steam condensate out   e. superheated juice out   h. throttle valve
c. vapor out   f. to heaters   i. desuperheated, L.P. steam, make-up
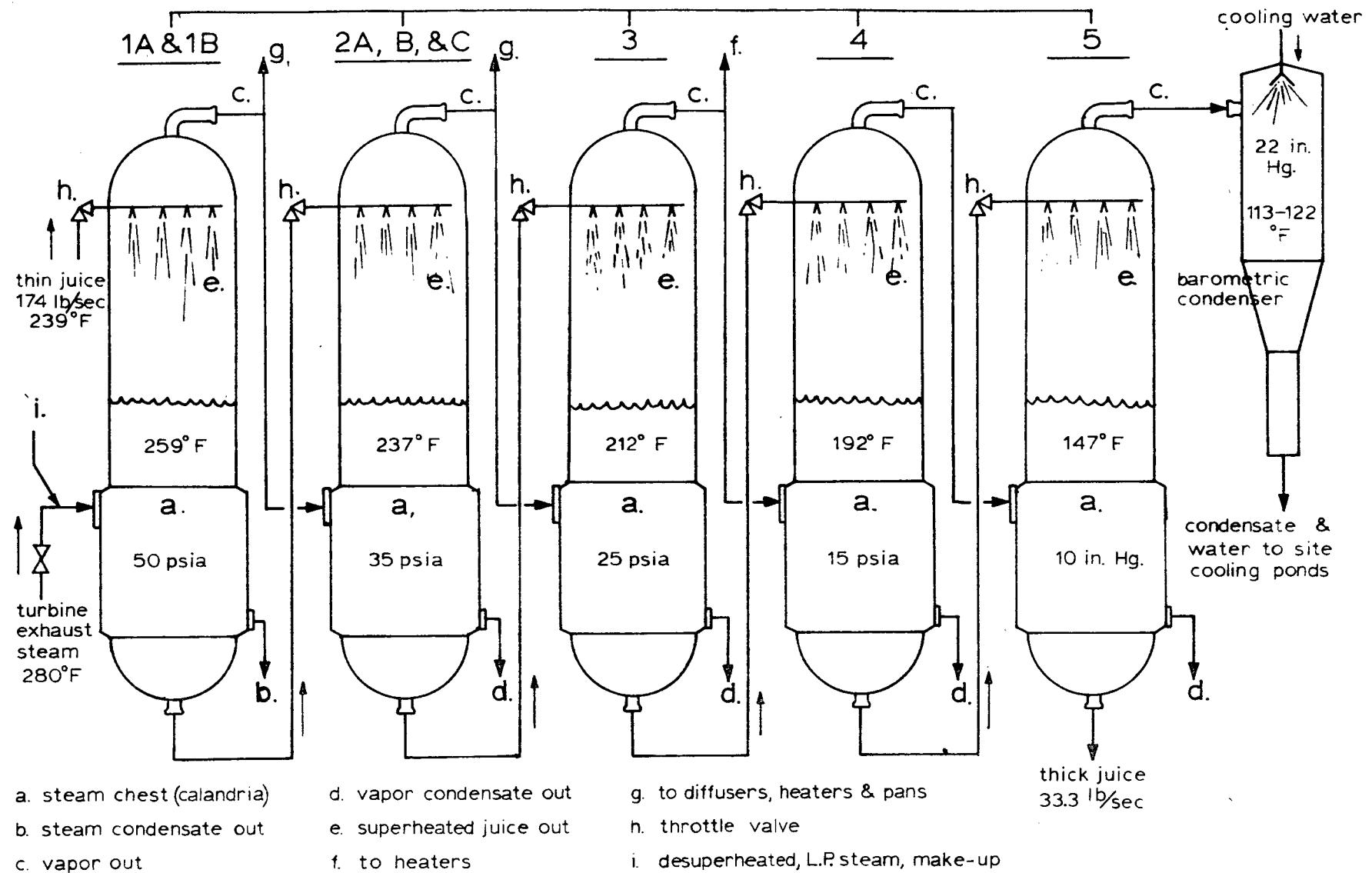
Figure 43.   Quintuple-effect evaporators.

Effect   Turbine Exhaust Steam
(77.6 lb/sec @ 50 psia)

280°F

	Juice Vapor abso. press (psia), flow rate (lb/sec)	To Process abso. press (psia rate (lb/sec)
1st Effect (1A) → Condensate to boiler (77.6 lb/sec) ← (1B)	35 psia 67.3 lb/sec →	35 psia 15.2 lb/sec to heaters
(2A)	51.8 lb/sec	
2nd Effect (2B) 237°F (2C)	22 to 25 psia 55.6 lb/sec →	22 to 25 psia 52.3 lb/sec to diffusers, heaters and pans
	5.3 lb/sec	
3rd Effect 212°F (3)	15 psia 5.3 lb/sec	
4th Effect 192°F (4)	10 in Hg 5.3 lb/sec	
5th Effect 147°F (5)	22 in Hg 7.1 lb/sec	
Barometric Condenser 122°F	To Barometric Condenser	

Liquid (122°F) to detention ponds

Figure 43A.   Quintuple-effect evaporator flow diagram.

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By evaporation the percentage of dissolved solids in the juice is raised from 10 to 15 percent to 50 to 65 percent and the outflow is called thick juice.

4) Ion Exchange

The role of ion exchange is to exchange Ca ions with Mg ions which bind up less sucrose, resulting in increased extraction (less molasses). Ion exchange is accomplished by passing juices through beds of synthetic ion exchange resins. In the 6,600-ton Nyssa plant, with 15 percent sugar in beets, the increase in extraction can increase white sugar production by 240 bags (100 pounds) a day.

5) Crystallization

Sugar is crystallized by pan boiling in the vacuum pans. The boiling takes place at low pressure and thus low temperature in order to avoid caramelization.

A quantity of juice is boiled in the pan under vacuum, until the juice is supersaturated. The liquor is either shocked to start crystal formation by the addition of a small amount of powdered sugar, or it is seeded at a lower saturation by addition of finely milled sugar in a slurry with isopropyl alcohol.

When crystals are of the desired size and number, they are discharged from the vacuum pan into the mixer which slowly agitates the mass. From the mixer the mass of crystals is fed to centrifugals. The sugar centrifugal is a perforated basket which rotates around a vertical axis at high speed within an outer collector shell. The liquid surrounding the crystals is centrifuged or spun off, and leaves the basket through the perforations.

Following one or two brief washes with pure hot water, the wet white sugar crystals are discharged from the centrifugal basket, and are sent to the dryer or granulator and the cooler. Hot, filtered air is passed through the granulator, and cool, filtered air is passed through the cooler. The granulated sugar is then screened, and either sacked immediately, or stored in bulk bins to await future packaging or bulk delivery.

A three-stage boiling scheme is used. The syrup spun from the third boiling is molasses, which is a by-product. Sugar may be recovered from molasses by the Steffen process. Part of the molasses is added to pulp to be used as livestock feed.

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6) Dried Molasses Beet Pulp

Wet pulp from the diffuser is run to vertical single-screw and horizontal double-screw pulp presses, where the moisture content is reduced from 95 percent to between 76 and 84 percent. After the addition of molasses the pressed pulp is dried to a moisture content of about 10 percent by hot air in a pulp dryer consisting of a horizontal rotating drum. Hot air enters the pulp dryer at 1800°F and leaves at 240°F. The pulp dryer consumes about 10 percent of the total energy produced by the plant.

The pulp is normally made into pellets in which form it is stored and sold for animal feed.

c. Power Production and Energy Requirements

Sugar processing requires large quantities of low-pressure process steam. The power plant uses a noncondensing steam turbine generator which will exhaust steam at the pressure required for process.

The inlet steam pressure to the turbine is 245 psia and 420 psia absolute, with the back pressure or exhaust at 50 psia. Approximately 110 pounds of steam per second is generated by the coal-fired boilers. Energy produced by the boilers is consumed by the following: 75 percent to evaporators, 4 percent to turbines, 6 percent live steam to process, 10 percent to evaporation to form concentrated Steffen Filtrate (CSF) and pulp dryers, and 5 percent to steam venting and losses.

During the 1976 campaign, the three steam turbine generators produced a total 15.3 million kw hr of electrical energy. Table XXI provides a summary of energy used by the factory.

Bituminous coal from the Wyoming fields is the fuel for boilers. The company has a 25-year agreement with the coal suppliers, of which 12 years remain.

During the 1976 operating season (130 days), boilers produced 1.67×10^{12} Btu of thermal energy by burning 80,000 tons of coal. Boiler efficiency is rated at 76 percent and the heat content of the coal is 664 Btu/lb. Coal cost was approximately $.09 per therm. Approximately 1.20×10^6 Btu are required to produce a 100-pound bag of sugar.

d. Geothermal Application

Table XXI shows the steam balance from the boilers. The turbine generators consume approximately 4 percent and evaporators 75 percent of the total steam supplied. However, as has been discussed in section C, the evaporators utilize turbine exhaust steam.

TABLE XXI
STEAM BALANCE

	Application	Temperature °F	Absolute pressure psia	Steam use %
1.	Turbines	403 & 262	245 & 420	4
2.	Evaporators	280	40	75
3.	CSF & pulp dryers	424	55	10
4.	Live steam	403	245	6
5.	Venting & losses	varies	varies	5

The high use of energy in the evaporation process makes it an attractive candidate for conversion to geothermal energy. Even though some of its energy needs are currently supplied from waste heat generated by electricity production, a large part of the energy loads of the plant could be satisfied if the evaporation process was to be adapted to use of geothermal energy.

Two ways of doing this are apparent. One method would use the total flow (Figure 44) of geothermal fluid through the first effect. The second alternative would employ only steam flashed from the geothermal fluid in the first effect, the water fraction of the flow being discarded. Both methods have been investigated and will be discussed, but the latter was considered the more attractive scheme and costs for the conversion were based on the assumption that it would be used.

Total Flow Method

A prime consideration in using this method is the heat transferring capability of the first effect when the hot side fluid is predominantly water rather than steam, which is now used. An estimate of this capability follows.

Present Overall Heat Transfer Coefficient

The first effect actually consists of two vertical-tube, shell-and-tube heat exchangers containing 8,174 and 3,938 tubes, respectively, having a 1.25-inch o.d. The general configuration of these exchangers is shown in Figure 45. As currently operated, saturated steam at 280°F and 49.74 psia is condensed at a rate of 77.44 lb/sec to deliver energy at a rate of 71,518 Btu/sec. On the cold side, juice at a lower pressure enters at 239°F and is

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first-effect
evaporators

Vapor

Flow From Wells

Thick Juice

Hot Water
Two-Phase

Water Out

Juice

reservoir

Figure 44. Total Flow Method
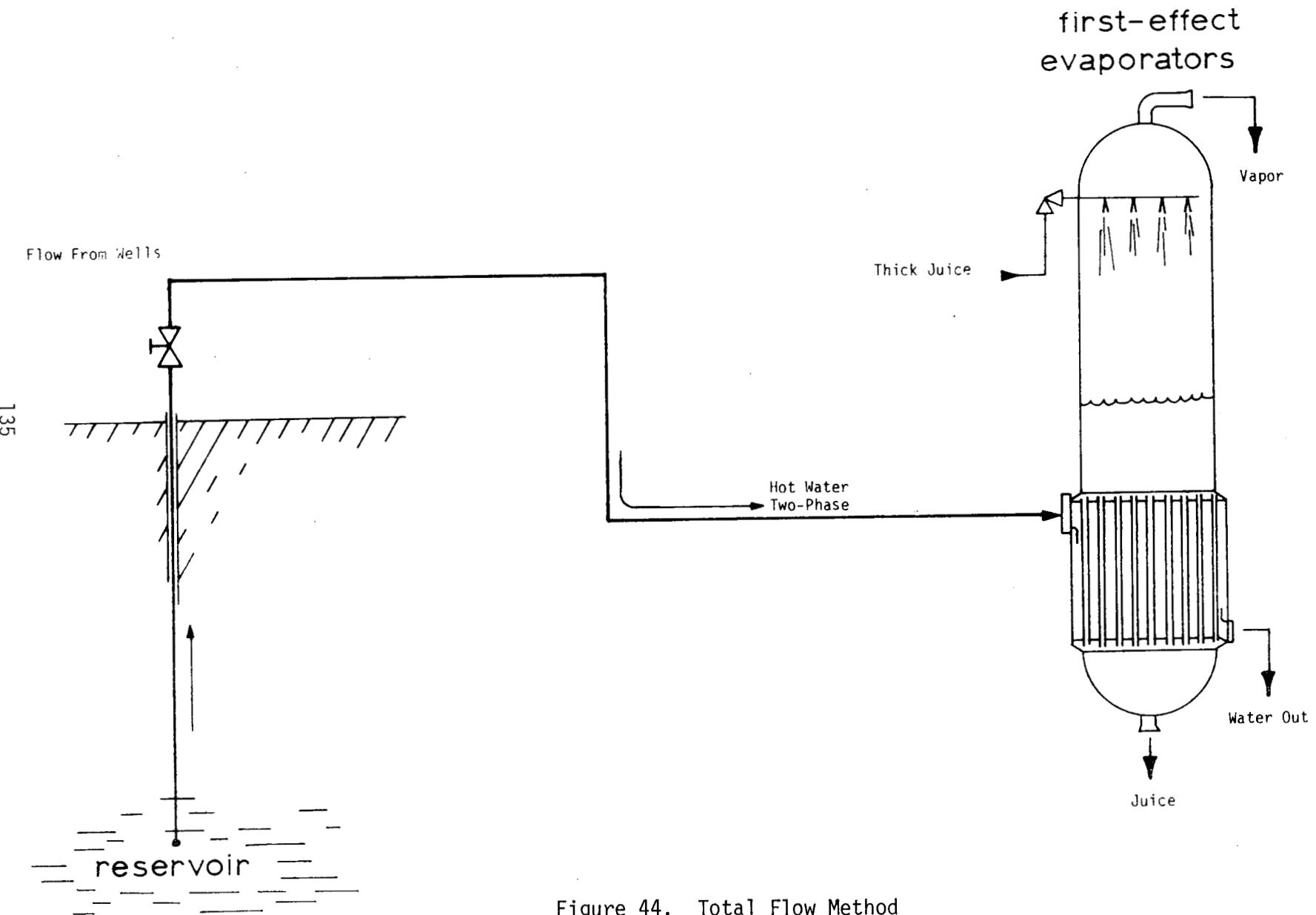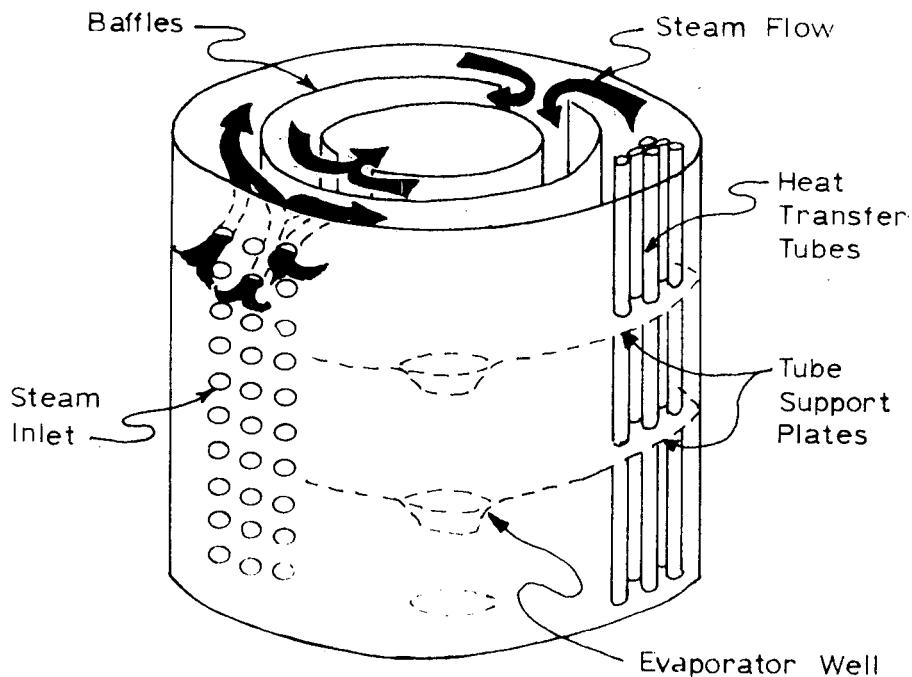
Figure 45. Evaporator heat exchanger configuration.
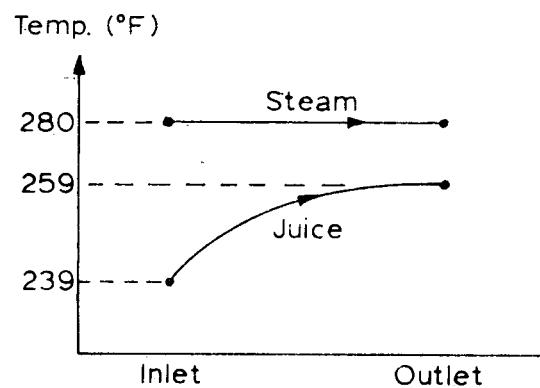
Figure 46. Temperature profile of first-effect
evaporator heat exchanger.

heated to saturation at 259°F. It is then vaporized at a rate of 67.1 lb/sec. The total energy, Q, delivered to the juice in the first effect is 66,571 Btu/sec. The temperature profile in the first effect is shown in Figure 46; the corresponding log-mean temperature difference, ΔT_m, is 30°F. As the total (outside) heat transfer area, A, of the first effect is 35,926 ft^2, the overall (outside) heat transfer coefficient is:

$$U_{steam} = \frac{Q}{A\Delta T_m} = 210 \frac{Btu}{hr\ ft^2 °F}$$

New Overall Heat Transfer Coefficient

The general expression for U is:

$$U = \frac{1}{\frac{1}{h_o} + R_{f_o} + [R_t + R_{f_i}\frac{A_o}{A_i} + \frac{1}{h_i}\frac{A_o}{A_i}]}$$

where A_i = inside tube surface area

        A_o = outside tube surface area

        h_i = inside film coefficient

        h_o = outside film coefficient

        R_{f_i} = inside fouling resistance

        R_{f_o} = outside fouling resistance

        R_t = tube resistance

All of the bracketed terms in the denominator will be essentially unchanged when the current shell fluid (steam) is replaced by geo-thermal fluid. The sum of these terms may be evaluated, once h_o and R_{f_o} are estimated when the outside fluid is steam, using:

$$\underline{X} \triangleq [R_t + \cdots + \frac{1}{h_i}\frac{A_o}{A_i}] = \frac{1}{U_{steam}} - [\frac{1}{h_o} + R_{f_o}]_{steam}$$

Assuming film-type condensation $h_{o_{steam}}$ is estimated from:

$$h = \Phi_f \times A_1 \times (\frac{4\Gamma}{\mu f})^{-1/3} \quad (1)$$

where A_1 1.47 (for vertical tubes)

$$\Phi_f = \frac{h_f{}^3 \rho_f{}^2 g}{\mu^2 f}$$

h_f = thermal conductivity of condensate at film temperature

ρf = density of condensate at film temperature

g = acceleration of gravity

μf = absolute viscosity of condensate at film temperature

and $\Gamma = \dfrac{\text{mass flow rate of condensate per tube (lb/hr)}}{\pi \times \text{tube diameter (ft)}}$

An approximate average condensate flow rate is established next. Assuming the steam flow rate in each exchanger is proportional to the number of steam admission holes in the exchanger (124 and 84), the condensate mass flows are, respectively, 16.6 x 10^4 lb/hr and 11.3 x 10^4 lb/hr. The number of tube segments (the tubes are divided into segments by the support plates) in the larger exchanger is 32,696 and 7,876 in the smaller one. The condensate mass flow rates for the larger and smaller exchangers are 5.08 and 14.4, respectively. A flow-rate weighted average value is then:

$$8.9 \text{ lb/hr}$$

and $\Gamma = \pi \times \dfrac{8.9}{1.25} \times 12 = 27.2 \dfrac{\text{lb}}{\text{hr ft}}$

At the mean film temperature of 265°F, μf = .517 $\dfrac{\text{lb}}{\text{hr ft}}$, and Φ_f = 6918, giving an outside film coefficient of:

$$h_o = 1710 \dfrac{\text{Btu}}{\text{hr ft}^2 \text{ °F}}$$

A reasonable value for the outside fouling resistance is:

[2] $0.0005 \dfrac{\text{hr ft}^2 \text{ °F}}{\text{Btu}}$

So finally:

$$\underline{X} = [R_t + \cdots + \frac{1}{h_i}\frac{A_o}{a_i}] = \frac{1}{210} - [\frac{1}{1710} + 0.0005] = 0.0037 \frac{(\text{hr ft}^2 \text{ °F})}{\text{Btu}}$$

A reasonable value for the outside fouling resistance to be expected with geothermal fluid on the shell side is felt to be:

$$[1],[3] \quad 0.003 \ \frac{hr \ ft^2 \ °F}{Btu}$$

The outside film coefficient for this case may be found from [1]:

$$h_o = 370 \ (1 + 0.006 \times T_f) \ \frac{V_{max}^{0.6}}{D_o^{0.4}}$$

where T_f = average film temperature, °F

V_{max} = maximum shell side fluid velocity, ft/sec

and D_o = outside tube diameter, inches

V_{max} may be approximated after the quantity of geothermal fluid required is established. It is assumed this will be available at a temperature of 327°F and a quality of 8.3 percent [4], and that the exchanger pinch point temperature difference is 20°F, as before. The energy extracted under these conditions from the geothermal fluid is 122 Btu/lb. Thus, to supply the same energy (71,518 Btu/sec) as is currently obtained from steam, the geothermal fluid flow rate must be 586 lb/sec (10.1 ft³/sec, approximately). From the tube bundle and baffle geometry of the first-effect exchangers, the average maximum velocity of the geothermal fluid can now be estimated to be about 0.5 ft/sec. Taking the film temperature to be 276°F the outside film coefficient for the geothermal fluid case is:

$$h_{o_{g.f.}} = 370 \ (1 + 0.006 \times 276) \ \frac{.5^{0.6}}{1.25^{0.4}} = \frac{Btu}{hr \ ft^2 \ °F}$$

For the geothermal case, then:

$$U = \frac{1}{\frac{1}{593} + 0.003 + 0.0037} = 119 \ \frac{Btu}{hr \ ft^2 \ °F}$$

Since ΔT_m = 47°F with geothermal fluid on the shell side,

$$Q = 119 \times 35,926 \times 47 = 2 \times 10^8 \ Btu/hr,$$

which is about 13 percent less than the current heat transfer rate.

The uncertainties involved in this calculation only allow one to conclude that geothermal fluid can be used in place of steam to operate the first effect with the possible necessity of using some additional heat exchanger capacity.

Flashed Steam Method

The geothermal fluid is again assumed to be available at 327°F and 8.3 percent quality, fixing the enthalpy at 369 Btu/lb. If the fluid is throttled down to a pressure of about 49 psia some of it will flash to steam at 280°F. Specifically, .125 lb. of steam will be available for each pound of geothermal fluid that is throttled. Further, this steam will be exactly at the conditions of the steam currently used. So, to obtain 77.4 lb/sec of steam, the quantity currently used, the quantity of geothermal fluid required would be about 620 lb/sec. It is estimated that seven self-flowing wells would provide this flow rate, and two injection wells would be adequate for disposing of the waste.

A general plan for implementing this scheme is illustrated in Figure 47. All wells are interconnected so they feed a common line to the steam flasher or their outputs can be directly disposed of via the injection wells. Provision is also made for disposing of the well flow in a surface pond through a silencer unit.

Water separated out at the steam flasher is routed to the disposal lines where it joins the condensate returning from the plant. Some of the condensate may be diverted to the flasher for the purpose of scrubbing the flashed steam. The 22-inch steam delivery line and the 6-inch condensate return line run from the well field to the plant in a reinforced concrete conduit, as illustrated in Figure 48. The removable top of the conduit would be at ground level. The 1,200-foot long path of the pipeline is shown in Figure 48, which is adapted from an aerial photograph of the plant and surroundings. The portion of the pipeline near the plant is elevated on stanchions about 20 feet above ground.

e. Economic Analysis

The economic assessment of the Amalgamated Sugar Company presents several factors unique to this company. In 1964, Amalgamated obtained a 25-year coal contract at a price of $10 per ton. With 12 years remaining on this contract, the inflation rate for the next 12 years will consist of labor and transportation which is currently $10.75 per ton, inflating at a rate of 7.5 percent annually. Amalgamated currently uses 615 tons per day for 120 days per year. Also in converting to geothermal energy, Amalgamated could salvage their pollution control equipment, which has a current book value of $2 million. It is estimated that this equipment would salvage for about $650,000 after removal costs, providing a loss of $1,350,000 on the sale of this equipment and a tax reduction of $648,000. Further, Amalgamated could reduce maintenance costs by $6,500 annually that are currently inflating at a rate of 6 percent per annum. The maintenance force could also be reduced from five to two men resulting
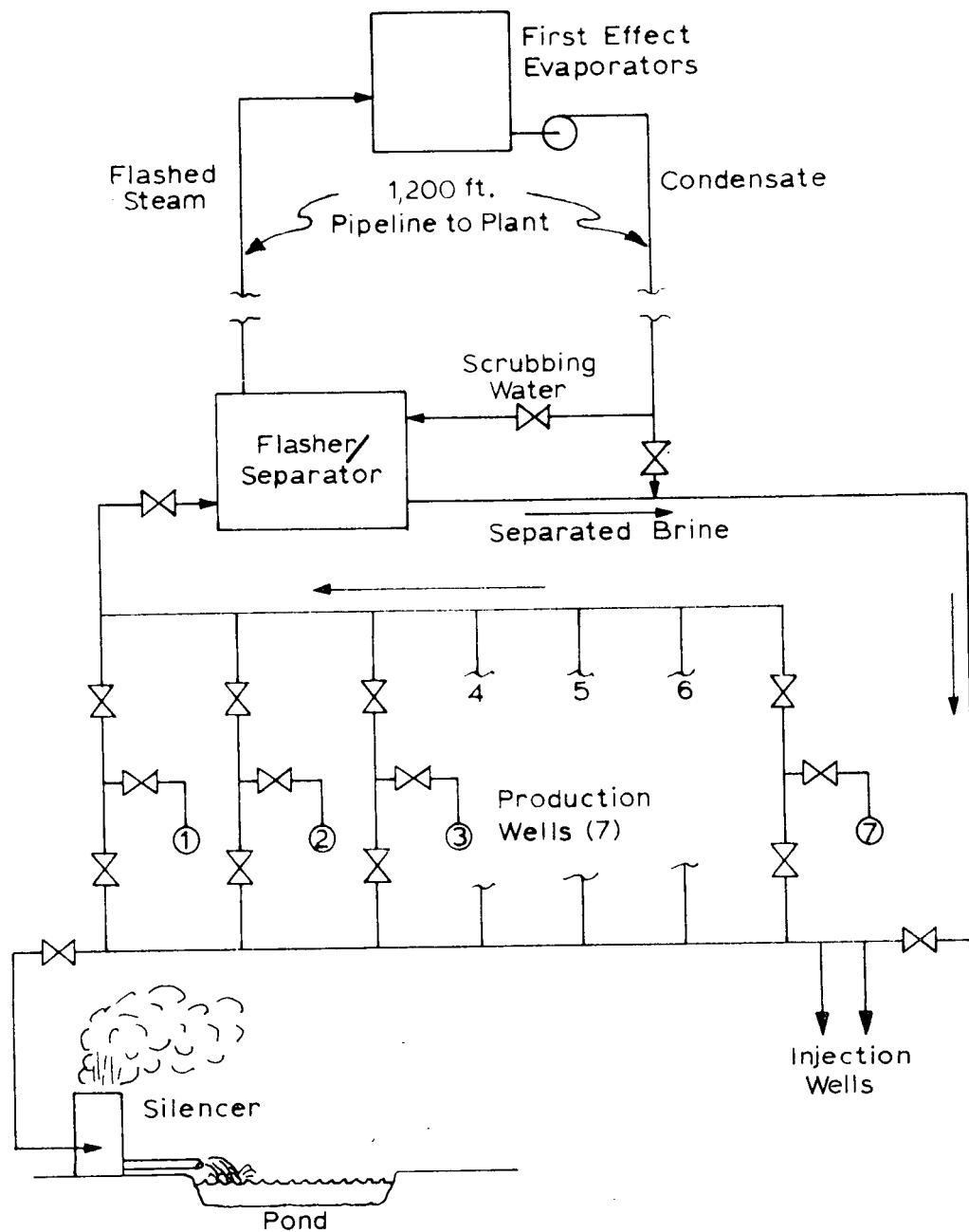
Figure 47.   Amalgamated Sugar Company
Flow Diagram for Geothermal Conversion

Figure 48. Amalgamated Sugar Company
Plant and Well Layout
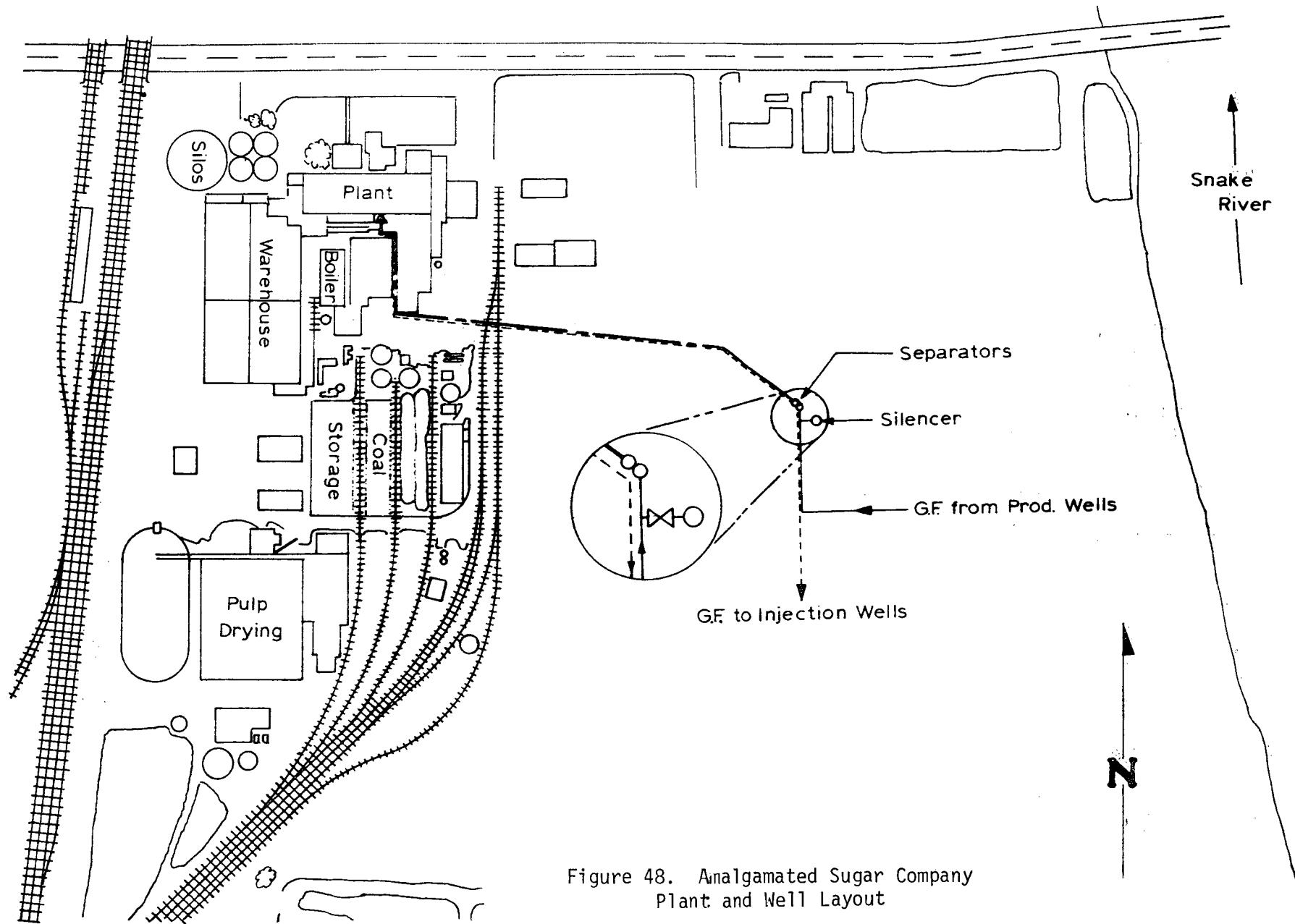
in an annual savings of three men at $6.50/hr/man, 8 hours per
day, 120 days per year for a total annual savings of $18,720.
These costs are also inflating at 6 percent per annum.

Costs of electrical power would decrease by $3,900 per year due
to shut down of pollution control equipment and would increase
by $166,000 because of shutting down the steam turbines which
currently produce 1,530,000 kWh annually. The geothermal con-
version would add 136 kWh for the operation of two 70-hp pumps
on the return wells plus a 15-hp condensate pump operating at
85 percent efficiency. The total annual cost for geothermal
operation then, is 136 kWh at .01085/kWh for 24 hr/day 120
days/year equals $4,250. Therefore, total annual power costs
for the geothermal system are:

Pollution control shutdown	($ 3,900)
Turbine shutdown	166,000
Geothermal operation	4,250
	$166,350

The cost of electrical energy is assumed to inflate at 8.5 per-
cent through 1986 and 7.38 percent thereafter.

The following table presents a ten-year projection of all oper-
ating costs at their respective inflation rates.

TABLE XXII
OPERATING COSTS

Year	A Projected annual cost of delivered coal	B Pollution control and maintenance cost	C Increased power costs	D Geothermal system annual maintenance	E Total annual savings before depletion and taxes. A+B-(C+D)
1978	$1,590,851	$25,220	$166,350	$ 8,000	$1,441,721
1979	1,654,814	26,733	180,490	8,480	1,492,578
1980	1,723,576	28,337	195,831	8,989	1,547,093
1981	1,797,494	30,037	212,477	9,528	1,605,526
1982	1,876,956	31,840	230,538	10,100	1,668,158
1983	1,962,378	33,750	250,133	10,706	1,735,289
1984	2,054,207	35,775	271,395	11,348	1,807,239
1985	2,152,922	37,922	294,463	12,029	1,884,352
1986	2,259,041	40,197	319,493	12,751	1,966,994
1987	2,373,119	42,609	346,649	13,516	2,055,563

A depletion allowance for savings from geothermal conversion is antici-
pated as follows:

1978 through 1980 - 22 percent   1983 - 16 percent
            1981 - 20 percent   1984 on - 15 percent
            1982 - 18 percent

This depletion allowance is subtracted from the total annual savings to
lower federal taxes due to lower energy costs.

TABLE XXII (continued)
Operating Costs

Year	Percent	F Depletion allowance indicated % of column E	G Tax increase due to reduced costs (E - F) .48	After tax cash inflow from operations E - G
1978	22	$317,179	$539,780	$ 901,941
1979	22	328,367	558,821	933,757
1980	22	340,360	579,232	967,861
1981	20	321,105	616,522	989,004
1982	18	300,268	656,587	1,011,571
1983	16	277,646	699,669	1,035,621
1984	15	271,086	737,354	1,069,886
1985	15	282,653	768,816	1,115,536
1986	15	295,049	802,534	1,164,460
1987	15	308,334	838,670	1,216,893

TABLE XXIII
AMALGAMATED SUGAR COMPANY

Conversion Costs for Geothermal Energy

Item	Tangible
Steam separator	$ 57,400
Silencer	18,000
Wellhead valving @ 25,000/well	
9 wells required (7 supply, 2 return)	225,000
Return well pumps 70 hp @ 40,000 each	80,000
Condensate pump 15 hp	500
Piping (includes installation) 1,200 feet 22" and 8"	168,400
Trenching	54,000
Power line	19,300
Transformer	35,000
Engineering @ 10%	65,760
Contingency @ 10%	65,760
	$789,120

	Intangible
Drill 9 wells	$5,121,000
Contingency @ 20%	1,024,200
	$6,145,200

TOTAL CAPITAL INVESTMENT	$6,934,320

Tangible asset costs in the first year total $789,120. Assuming a ten-year life and a 10 percent salvage value, annual straight-line depreciation would be $71,021 providing a cash inflow of $34,090 annually in reduced taxes.

At the end of the first year additional cash inflow would result as follows:

Expensing intangible cost of $6,145,200 provides $2,949,696

Loss on sale of pollution equipment	1,350,000	648,000
Cash received from sale of equipment		650,000
Investment tax credit @ 20%	(789,120)	157,824
		$4,405,520
Depreciation (straight line)		34,090
After-tax inflow from operations		901,941
Total first-year cash inflow		$5,341,551

Total capital investment at
year zero $6,934,320

Ten-year projection of cash inflow after taxes:

Year	Cash inflow	Discounted @ 20%	Present worth of cash inflows @ 30%	@ 27%
1978	$5,341,551	$4,451,293	$4,108,885	$4,205,946
1979	967,847	672,116	572,691	600,066
1980	1,001,951	579,833	456,054	489,142
1981	1,023,094	493,390	358,214	393,279
1982	1,045,661	420,228	281,627	316,499
1983	1,069,711	358,244*	221,619	254,944
1984	1,103,976		175,937	207,173
1985	1,149,626		140,932	169,874
1986	1,198,550		113,023	139,451
1987	1,250,983		90,744	114,608
			$6,519,725	$6,890,982

*Payback occurs in sixth year @ 20%

ROI ≈ 26%

3. Ore-Ida Foods, Inc., Ontario, Oregon

   a. Introduction

   Ore-Ida Foods, Inc., a division of H. J. Heinz Company, is located
   on the Oregon-Idaho border near the Snake River at Ontario, Oregon.
   Their major product is frozen potato products processed from
   August 1 through June 31. There is an additional seasonal process-
   ing of corn and onions for seven weeks and six months respectively.
   This plant processes over two million pounds of potatoes per day
   resulting in over one million pounds of frozen potato products.

   The plant occupies 187,000 ft^2 which includes all processing and
   package areas. Two natural gas-fired boilers supply an average
   of 120,000 lb/hr steam to process with 40 percent returned as a
   condensate. All processes except frying utilize direct injection
   of steam at 100 psig. Saturated frying employs heat exchangers
   and steam at 275 psig. The fryers consume 45 percent of the
   energy of the plant and since the return temperature is greater
   than 300°F, the assumed geothermal water supply temperature, 55
   percent of the process energy requirements can be supplied by
   geothermal energy.

   The energy consumption for the 1976 calendar year was:

   1. Heating: 290,000 therms per year at a cost of $65,075

   2. Processing: Natural gas--4,394,326 therms at a cost of
                  $880,904

                  Oil--816,081 gallons at a cost of $297,870

   Natural gas availability is dependent upon weather conditions and
   gas utility contracts. According to company spokesmen, it appears
   that the trend for industrial fuel is away from natural gas and
   toward fuel oils and possibly coal. At present the availability
   of fuel oil appears to be quite solid and will continue to be so
   in the near future.

   b. Process Steps

   To understand the potato process methods and energy requirements
   for each step, the accompanying composite flow sheet, Figure 49,
   and following description from an Ore-Ida publication is used
   to explain potato processing at the Ontario plant.

   There are two prime french-fry potato lines and several by-product
   lines. Potatoes for processing are conveyed to a battery of
   scrubbers and then moved into a preheater, which warms the potatoes
   and softens the peel, making it easier to remove the skin. The
   potatoes are then chemically peeled by a 15 percent lye solution.
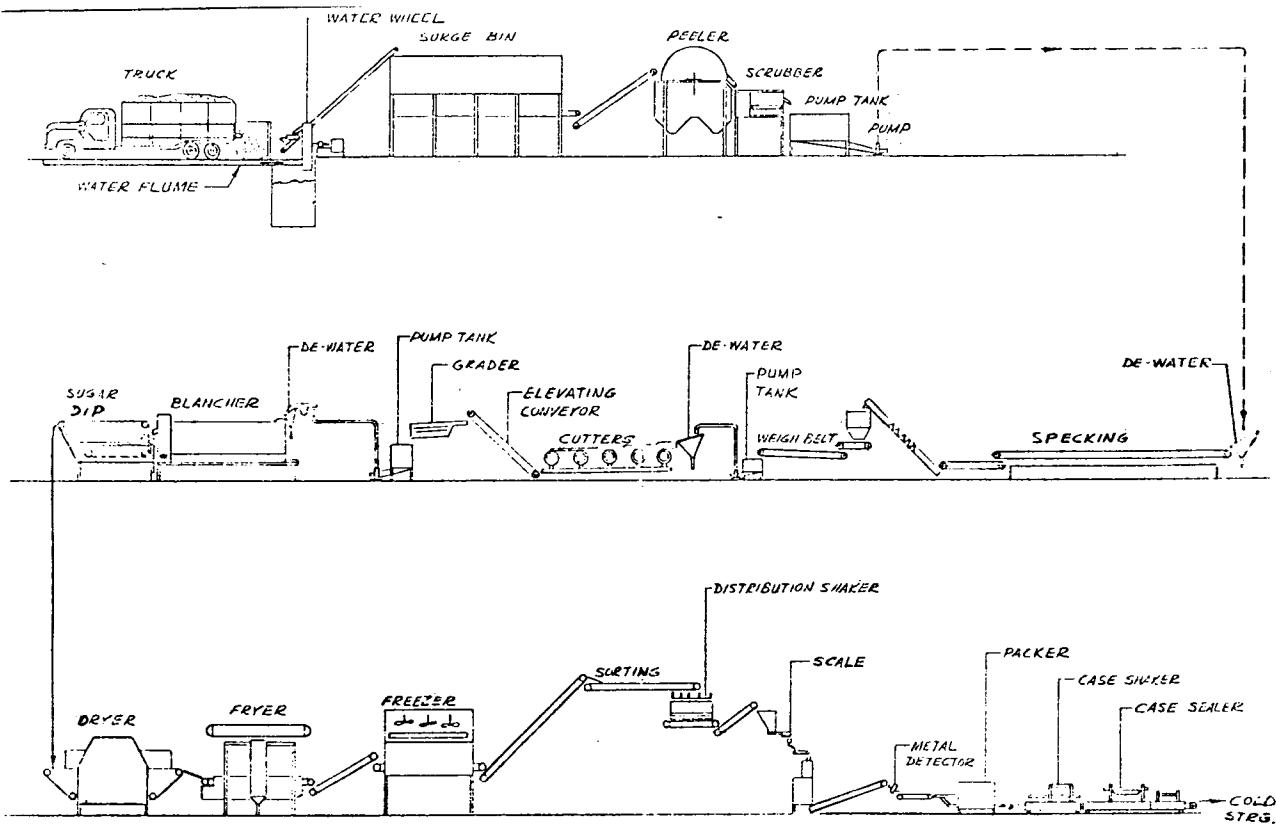
Figure 49. Ore-Ida Foods, Inc.
Schematic Process Flow Chart

Heat for peeling, 24,460,000 Btu/hr is supplied by the direct injection of steam at 100 psig, maintaining the solution at a temperature of 140° to 175°F.

Upon leaving the chemical peeler, the potatoes are conveyed to a battery of scrubbers, where the peeling is removed. After the scrubbers, the peeled potatoes are subjected to another washing process and then conveyed to the trim tables by pumping. The peeling removed by the scrubbers is pumped to a holding tank and sold as cattle feed.

After the potatoes are trimmed for defects, the product is conveyed to cutter areas where a bank of Urschel cutters cut them to the desired style of french fries. Shakers sort the product

into appropriate lengths. Small lengths are separated and then processed into hash browns or tator tots. All processing equipment in the plant is made of stainless steel.

The properly trimmed and sized french fries are then carried by gravity to the blanching system on the floor below.

After blanching, the potatoes are dewatered and fed through a sugar drag, which adds a slight amount of dextrose to the surface of the potato, which will impart a golden color when the potatoes are fried. They then pass through a dryer which removes the surface moisture prior to a two-stage frying process. The first stage cooks the product more completely, while the second stage gives it the golden color. The oil in the fryers is heated to 375°F by heat exchangers receiving steam at 275 psig. The frying process requires 43,135,000 Btu/hr. All fryers were designed and built to Ore-Ida specifications to produce the desired results.

Cleanup, miscellaneous use and plant heat requires about 2,620 lb/hr of steam, or 2.55 x 106 Btu/hr. The shorter pieces which have been delegated for the making of tater tots go into a water blancher, then to cutters to be diced, and finally to a mixer, where flavoring ingredients are added.

Freezing of the products is Individual Quick Freeze (IQF) in Lewis continuous freezing systems powered by Sullair and Mycom compressors. Freezing temperatures are maintained at a constant -30°F.

The products, 13 different varieties, are now ready for packaging. They are again mechanically sized and hand-sorted before they are fed onto exact portion scales and the polybags are filled.

Product pours out of the plant 24 hours a day, engaging three shifts of workers, a total of 900 people, and the pace continues 11 months per year.

c. Energy Requirements

The heat consumption rate, which largely determines the extent of the geothermal resource required, totals 106,545,000 Btu/hr. This includes all potato processing and plant heating. Of this amount, 43,135,000 Btu/hr are used in the frying process. As has been mentioned, the anticipated resource temperature of 300°F precludes the direct use of geothermal energy for frying, which is at 375°F. However, the remaining 63,410,000 Btu/hr can readily be satisfied geothermally. (The energy needed for the 2,300 tons of refrigeration used for freezing at -30°F has not been considered for replacement by geothermal energy due to the advanced state-of-the-art required for obtaining such low temperatures.)

To avoid any possible contamination of the product by the geo-thermal fluid, or the need for treatment of the fluid, energy is supplied to the process via intermediate heat exchangers. The geothermal fluid passing through these exchangers will transfer energy to a secondary fluid, primarily water, which delivers the energy to the process. The secondary fluid, cir-culating in a closed system, then returns to the intermediate heat exchanger to be reheated.

The processes to be supplied by the geothermal resource are distinguished in Table XXIV by their function and temperature requirements. The peeling process involves three distinct steps calling for input temperatures of 250°, 200° and 150°F. The hot blanch process uses an input temperature of 200°F and the warm blanch requires 150°F. Heating of the hot water used for various functions also calls for 150°F as does the plant heating system.

TABLE XXIV
Heat Loads and Secondary Fluid Temperatures

Function	Heat rate (million Btu/hr)	Temperature in (°F)	Temperature out (°F)
Peeling	4.12	260	200
Peeling	5.63	200	150
Peeling	14.6	150	100
Hot blanch	16.52	200	100
Warm blanch	8.92	150	100
Water heating	2.62	150	50
Plant heat	11.00	150	100

d. Geothermal Application

With an anticipated temperature drop of 170°F for the geothermal fluid used to supply the 63.4 million Btu/hr needed for process-ing, roughly 370,000 lb/hr will be required. This should be readily available from two wells, with adequate margin for load variation or delivery rate fluctuation. The wells would be pumped to minimize temperature losses. A third well would be required for injection of the waste fluid.

Figure 50 suggests one possible routing of the geothermal fluid through the intermediate hot exchangers for maximum extraction of energy. Energy requirements for the high-temperature (200°F or more) processes are satisfied by dropping the geothermal fluid temperature from 300°F to 190°F. The lower-temperature processes are then supplied partially by this cooled-off geothermal fluid and partially by fresh geothermal fluid.

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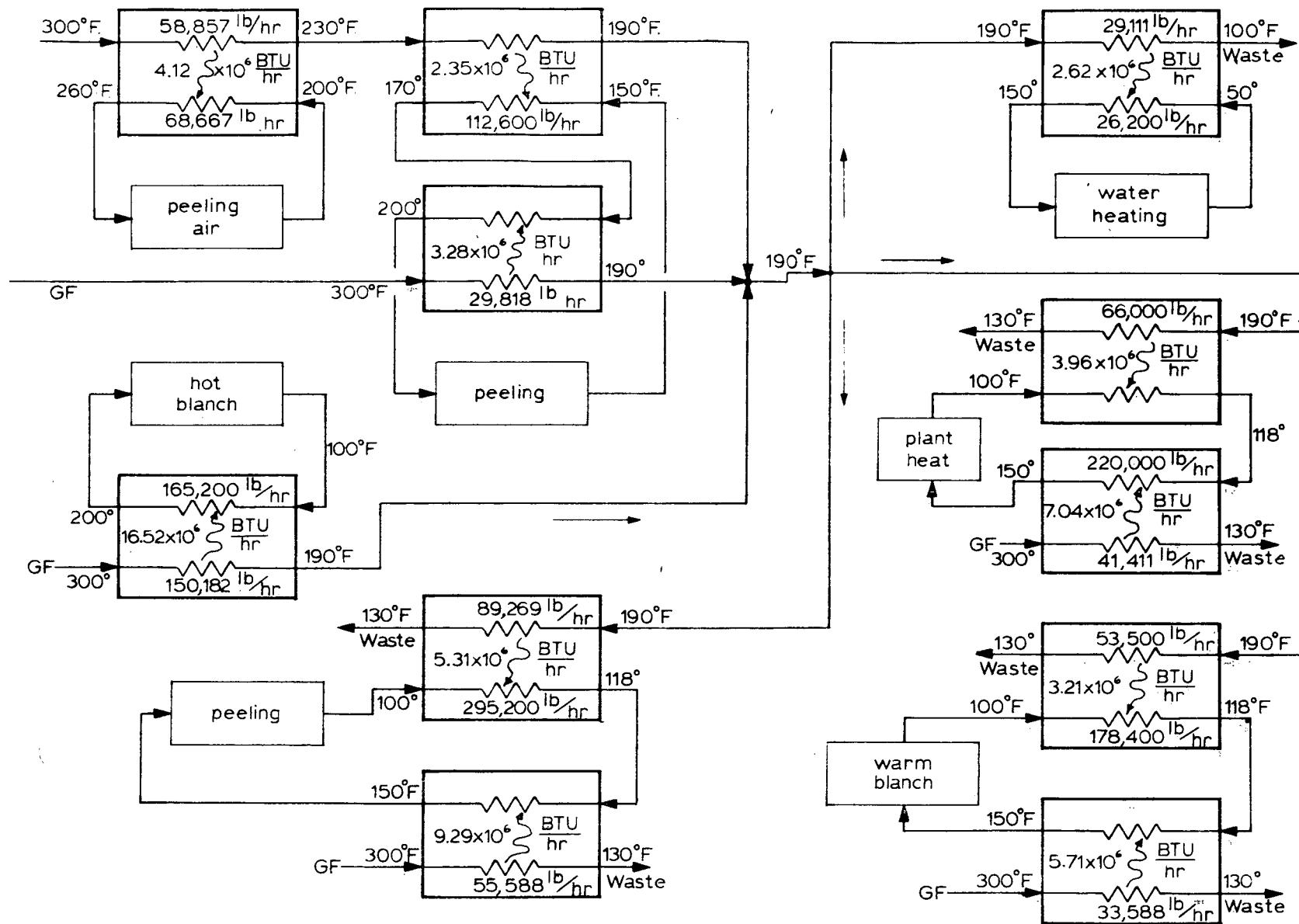
Figure 50. Ore-Ida Foods, Inc.
Flow Diagram for Geothermal Conversion

The intermediate heat exchangers could either be of the shell-and-tube design or the compact and versatile plate-type heat exchanger. The secondary fluid circulating to the processing tanks could either be used directly, or, as Ore-Ida representatives have considered, the fluid could pass through heat exchangers located at the processing tanks to heat the fluid in the tanks.

All of the secondary heat exchangers would be housed in a separate, new structure adjacent to the plant, along with the pumping and control equipment. A roughly 2,000-foot long pipeline, Figures 51 and 52, would carry fresh geothermal fluid from the well field, on company-owned property, to the heat exchanger building and waste fluid would be carried back from the building to the injection well.

Figure 53 indicates the pumping requirements for the system and also shows how control of the system could be achieved.

e. Economic Analysis

The economic analysis for the geothermal conversion of Ore-Ida Foods, Inc. assumes a ten-year depreciation life for tangible assets. Throughout the economic analysis, Ore-Ida's method of cost analysis was used. This requires 200 percent declining balance depreciation, after-tax cash flows from operations, expensing intangible costs in the year incurred, and discounting the after-tax cash flow for each year, to arrive at a present worth.

The calculation of annual savings from operations were accomplished as follows:

1) The fuel mix of natural gas and fuel oil that occurred in the year ending July 1977 was assumed to remain constant.

2) A 15-year projection of costs for natural gas to supply 100 percent space heating and 54.9 percent of process requirements was inflated at a rate of 11.2 percent annually through 1986, and 7.5 percent thereafter.

3) Costs of fuel oil were inflated at 7.5 percent annually for the 15-year projection.

4) Increased electrical power costs due to wellhead pumps and other components of the geothermal system were inflated at 8.5 percent annually through 1986, and 7.58 percent thereafter.

5) Maintenance and repair costs were inflated at 6 percent annually, which is the projected economic inflation rate.

All of the above inflation rate projections were obtained from the Oregon Department of Energy.

Well Site #1

Secondary Waste
Treatment

Snake River

Point of Application:
-Anchor/Expansion System -----------

Pipeline Prefered Route---——+——

Second Choice --- ——·——

Guide---)|(

Expansion Joint---

Anchor---

I-80

I-80

West

East

N.E. 3rd St.

N

U.P.R.R.

520

521

522

523

524

525

526

527

503

502

501

517

516

515

519

538

540

N.E. 2nd St.

529

N.E. 3rd St.

510

504

505

506

Well
Site
#2
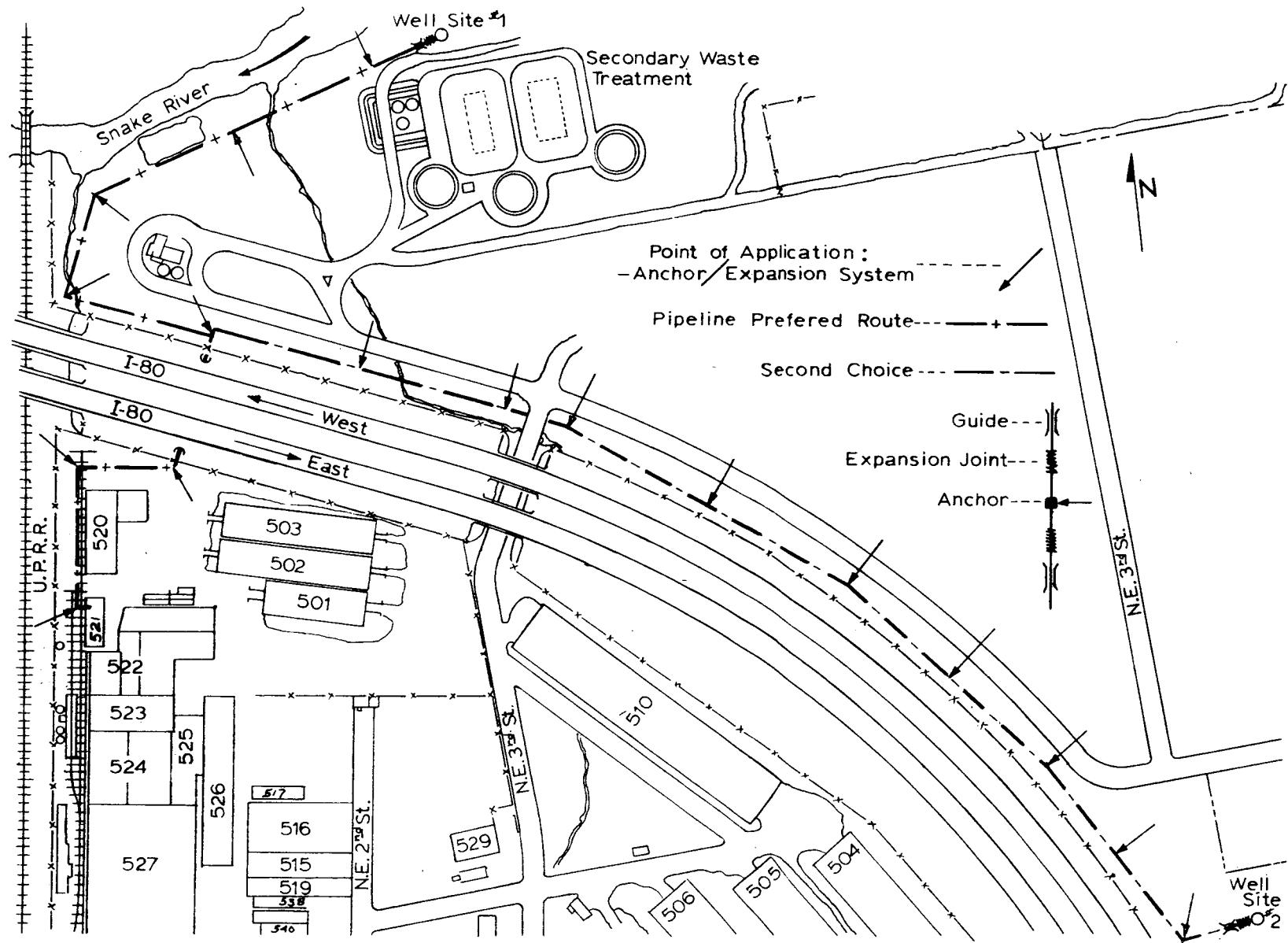
Figure 51. Ore-Ida Foods, Inc.

ORE - IDA FOODS, INC.

Cross Section of Transmission Line

Steel Pipe

G.F. Supply Line

Fiberglass Wrap
Insulation

Concrete Conduit

Power Cables

G.F. Return Line

Roller Pad

Roller

EXPANSION
JOINTS

Fixed Support
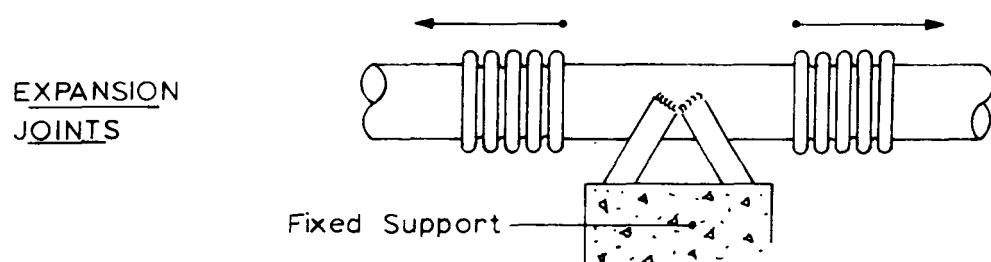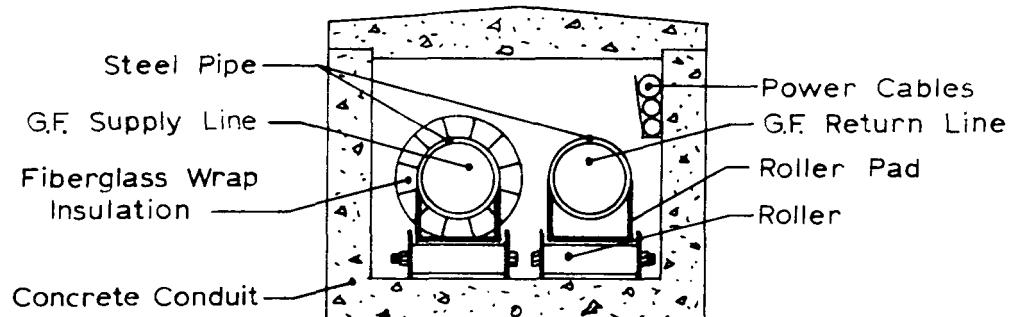
Figure 52. Cross-section of transmission line.
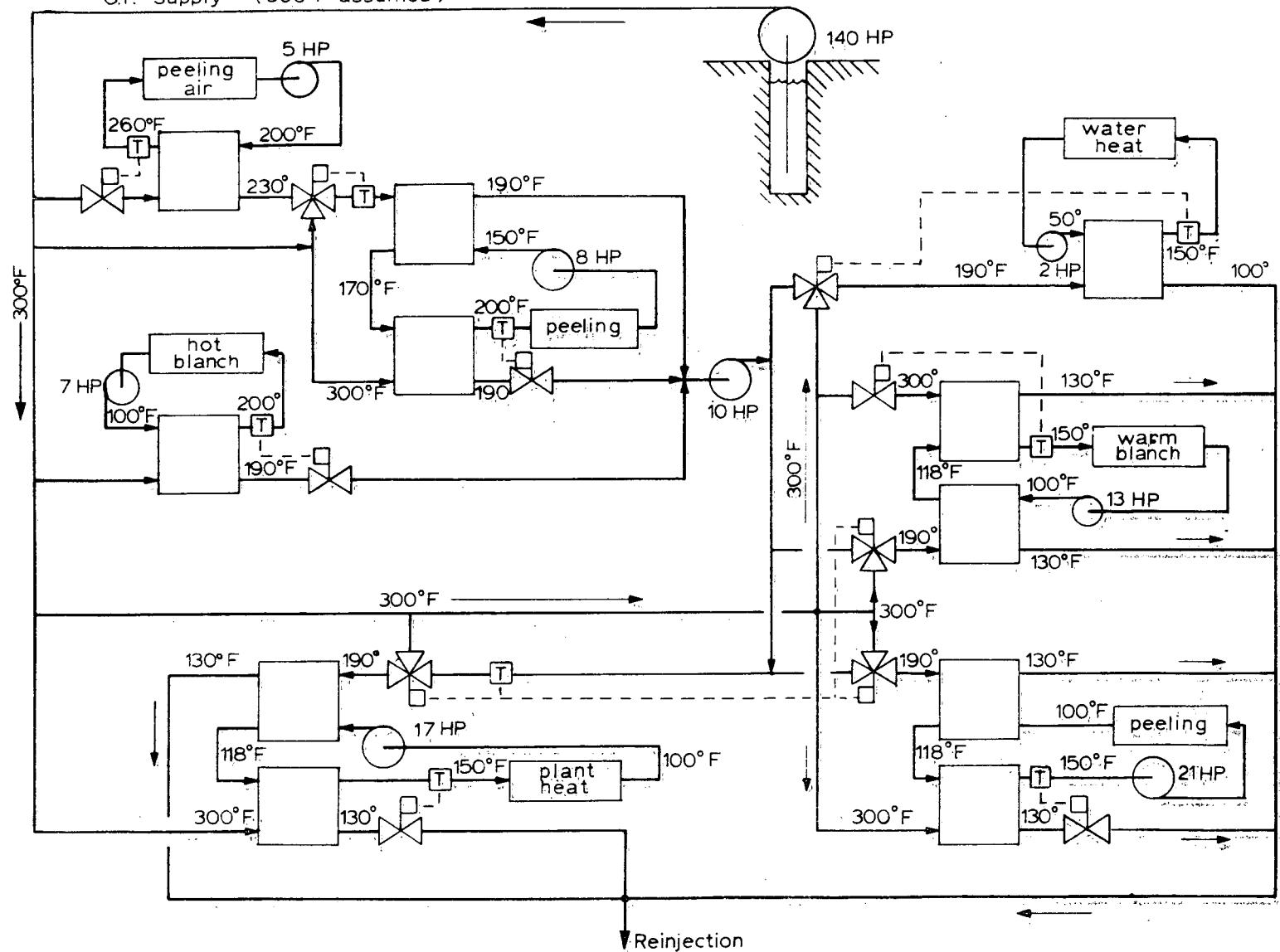
Figure 53. Ore-Ida Foods, Inc.
Control Diagram for Geothermal Conversion

Annual costs of the geothermal system were subtracted from the projected annual costs of conventional fuels to arrive at a total annual savings before taxes.

Depletion allowances were applied to these annual savings as follows:

    1979 and 1980 - 22 percent
            1981 - 20 percent
            1982 - 18 percent
            1983 - 16 percent
       1984 on - 15 percent

This coincides with information received from Senator Packwood regarding depletion allowances for geothermal conversions.

The depletion allowance was subtracted from annual savings and the result was multiplied by 48 percent to determine the increase in federal income tax due to cost reduction. This percentage (.48) is used by Ore-Ida in calculating after-tax cash flow.

The total capital outlay of $2,848,451 includes intangible costs after taxes of $1,321,840, and tangible costs of $1,526,611. On these latter costs, a 20 percent investment credit was taken at the end of year one.

All cash flows due to after-tax savings from operations, annual asset depletion and reduced federal taxes due to tax credits and tangible asset depreciation, were discounted at a rate of 20 percent compounded continuously, assuming uniform cash flow throughout each year to arrive at a present worth total of $4,389,908. A second present worth calculation was done at a rate of 30 percent compounded continuously, to provide Ore-Ida with a more accurate ROI.

The cost of drilling a productive well based on total intangible estimated costs would be $2,542,000 ÷ 3 = $847,333. The after-tax cost would be .52($847,333) = $440,613. In drilling a non-productive well these costs would be substantially reduced due to the fact that the well would require only surface casing and would not incur mobilization and demobilization cost. The esti-mated after-tax costs of a nonproducing well are estimated to be (.52)($658,000) = $342,000. Ore-Ida requires only two producing wells and one return well and the total after-tax dollars avail-able for intangible cost at 20 percent ROI are $1,321,840 + $1,541,457 - $2,863,297. Therefore, the company could afford to drill a total of eight wells to get two productive wells and use one of the nonproductive wells as a return well. In other words, with a confidence level of as low as 25 percent, they could still realize a 20 percent ROI.
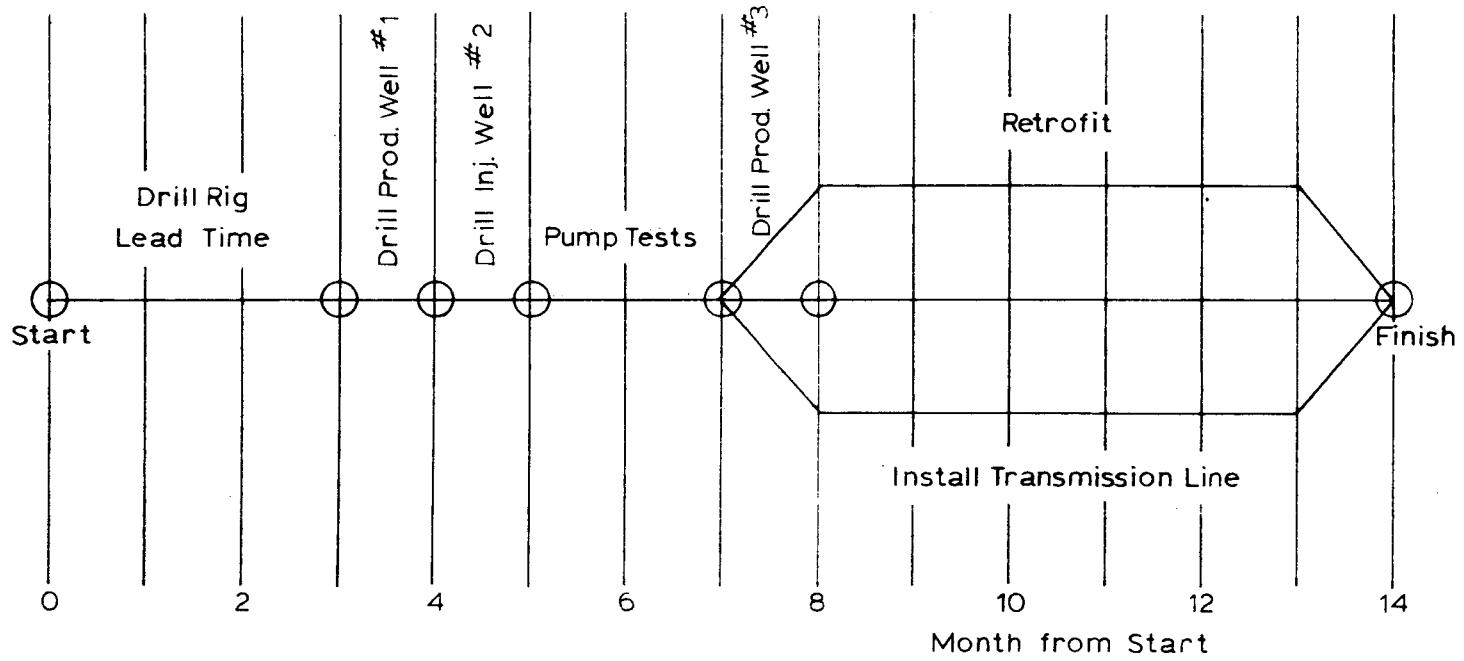
Figure 54. Ore-Ida Foods, Inc. development schedule.

TABLE XXV

ORE-IDA FOODS, INC.
Annual Savings Recap for Geothermal Conversion

Year	A Projected Costs for Fuel Oil	B Projected Costs for Natural Gas	C Projected Electrical Power Costs Geothermal	D Projected Maintenance and Repair Geothermal	E Total Savings Before Depletion and Taxes [A+B - (C+D)]	F Percentage Depletion Allowance (Indicated % Times Column E)	G Increased Federal Tax (E-F) .48	Annual Savings After Taxes (E-G)
1979	$188,981	$ 682,146	$11,318	$15,000	$ 844,809	22% $185,858	$ 316,296	$ 528,513
1980	203,142	760,593	12,280	15,900	935,555	22% 205,822	350,272	585,283
1981	218,391	848,061	13,323	16,854	1,036,275	20% 207,255	397,930	638,345
1982	234,770	945,588	14,456	17,865	1,148,037	18% 206,647	451,867	696,170
1983	252,378	1,054,331	15,685	18,937	1,272,087	16% 203,534	512,905	759,182
1984	271,306	1,175,579	17,018	20,073	1,409,794	15% 211,469	575,196	834,598
1985	291,654	1,310,771	18,464	21,278	1,562,683	15% 234,402	637,574	925,108
1986	313,528	1,461,510	20,034	22,554	1,732,450	15% 259,868	706,840	1,025,610
1987	337,043	1,571,123	21,553	23,908	1,862,705	15% 279,406	759,984	1,102,721
1988	362,320	1,688,957	23,186	25,342	2,002,749	15% 300,412	817,122	1,185,627
1989	389,495	1,815,629	24,944	26,863	2,153,317	15% 322,998	878,553	1,274,764
1990	418,707	1,951,802	26,835	28,474	2,315,200	15% 347,280	944,602	1,370,598
1991	450,110	2,098,187	28,869	30,183	2,489,245	15% 373,387	1,015,612	1,473,633
1992	483,868	2,255,551	31,057	31,994	2,676,368	15% 401,455	1,091,958	1,584,410
1993	520,158	2,424,717	33,411	33,914	2,877,550	15% 431,633	1,174,040	1,703,510

Electricity assumed to inflate at 8.5 percent annually through 1986 and 7.58 percent thereafter.

Maintenance and repair assumed to inflate at 6 percent annually.

TABLE XXVI

ORE-IDA FOODS, INC.

GEOTHERMAL CONVERSION

RETURN ON INVESTMENT

Year	Cash Flow From Operations After Taxes	Depreciation and Investment Credit	After Tax Cash Flow	After Tax Payback	D.F. 20%	Present Worth	D.F. 30%	Present Worth
0	($2,848,451)	$	($2,848,451)		1.0000	($2,848,451)		($2,848,451)
1	528,513	451,877	980,390	1.0	.9063	888,527	.8639	846,997
2	585,283	117,244	702,527	1.0	.7421	521,345	.6400	449,633
3	638,345	93,795	732,140	1.0	.6075	444,775	.4741	347,137
4	696,170	75,036	771,206	.56	.4974	383,598	.3513	270,887
5	759,182	60,029	819,211		.4072	333,583	.2602	213,170
6	834,598	48,023	882,621		.3334	294,266	.1928	170,144
7	925,108	38,419	963,527		.2730	263,043	.1428	137,600
8	1,025,610	30,735	1,056,345		.2235	236,093	.1058	111,756
9	1,102,721	24,588	1,127,309		.1830	206,298	.0784	88,353
10	1,185,627	19,670	1,205,297		.1498	180,553	.0581	69,981
11	1,274,764		1,274,764		.1227	156,414	.0430	54,831
12	1,370,598		1,370,598		.1004	137,608	.0319	43,674
13	1,473,633		1,473,633		.0822	121,133	.0236	34,787
14	1,584,410		1,584,410		.0673	106,631	.0175	27,708
15	1,703,510		1,703,510		.0551	93,863	.0130	22,069
		R.V. $163,919	163,919		.1353	22,178	.0498	8,163
				3.56		$1,541,457		$ 48,438

ROI = 30 percent

After Tax Payback 3.56 years

TABLE XXVII

ORE-IDA FOODS, INC.
Geothermal Conversion

First-Year Expenses and Investment Costs

Item	Intangible costs	Tangible costs
1. Drill 3 wells, $750,000 per well	$2,250,000	$
2. Wellhead equipment, $25,000 per well		75,000
3. Well pumps, 150 hp, $50,000 per well		150,000
4. Pump tests	35,000	
5. Geologist $200/day, 130 days	26,000	
6. Power line and transformer		67,205
7. Silencer		20,000
8. Transmission line, 2,000 feet		160,000
9. Heat exchanger building		100,000
10. Heat exchangers, installed		180,000
11. In-plant control valves and wiring, installed		50,000
12. Control unit		20,000
13. Vessels		20,000
14. In-plant piping		176,000
15. In-plant pumps, 8 pumps installed		28,618
16. Miscellaneous other pumps, installed		84,000
17. Engineering 10% of tangible costs		113,082
18. Contingency 25% (tangible)		282,706
19. Contingency intangible 10%	231,000	
TOTAL	$2,542,000	$1,526,611

Tax reduction .48 x $2,542,000   (1,220,160)

Cash flow after taxes $1,321,840

Total cash flow after taxes $2,848,451

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TABLE XXVIII

ORE-IDA FOODS, INC.

TANGIBLE ASSET DEPRECIATION

INVESTMENT $1,526,611

End of Year	Book Value	Depreciation	Tax Credit 48%
1	$1,221,289	$305,322	$451,877
2	977,031	244,258	117,244
3	781,625	195,406	93,795
4	625,300	156,325	75,036
5	500,240	125,060	60,029
6	400,192	100,048	48,023
7	320,154	80,039	38,419
8	256,123	64,031	30,735
9	204,898	51,225	24,588
10	163,919	40,980	19,670

R.V. $163,919

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VI. APPENDICES

APPENDIX A

COMPARATIVE COSTS OF CONVENTIONAL ENERGY SUPPLIES

Oregon's Energy Future, First Annual Report,
January 1, 1977

In considering the price forecasts, it is important to keep in mind the distinction between current prices and prices in real terms. When prices are shown in real terms ("constant dollars"), this means that the effects of general inflation have been removed.

Prices in current dollar terms include the effects of changes in real prices and increases caused by general inflation. These are the prices consumers actually pay. In the following discussion, projections of energy prices are discussed in both real and current dollar terms depending on the context. In this report, the Oregon Department of Energy assumes an annual rate of general inflation between 5.5 and 6.0 percent.

Electricity

As a result of the shift to thermal sources of electrical operation, the real price of electricity to Oregon rate payers will increase significantly during the next two decades. Specifically, DOE projects annual increases in the average real prices of electricity sold by Oregon's private and public utilities of 2.0 and 1.2 percent, respectively, for the next 20 years. Somewhat faster rates of increase are forecasted for the first ten years. Including the effects of general inflation, this translates into a-nual rate increases of approximately 8 percent for the private utilities and 7 percent for the public utilities.

TABLE A-I

AVERAGE ELECTRICITY PRICE PROJECTIONS
(¢/kwh)

| Year | Residential | | Commercial | Industrial |
	Private utilities	Public utilities		
1971	1.33	1.02	1.31	0.44
1976	1.92	1.41	1.82	0.74
1981	2.91	2.02	2.75	1.09
1986	4.40	2.91	4.13	1.59
1991	6.21	4.00	5.79	2.21
1996	8.78	5.53	8.17	3.12

Petroleum Products

In contrast with electricity, petroleum products and natural gas prices are a function of decisions made at the national and international level. Consequently, future fossil fuel prices will be affected only marginally by the rate at which Oregon or the Northwest demands increase. Since fossil fuel prices are not amendable to a rigorous treatment, a more arbitrary method was used to develop a price forecast.

To forecast petroleum prices, the following assumptions are adopted:
(1) the prices of crude oil from the Organization of Petroleum Exporting Countries, domestic production, and Alaska (North Slope) will be constant

in real terms (i.e., actual prices will increase at a rate equal to the general inflation rate) for the duration of the forecast period; (2) the Pacific Northwest's dependence on Alaskan crude oil will increase steadily to the point that, by 1990, most West Coast oil prices will come from this source; and (3) petroleum products prices will rise at the same rate as the average price of crude oil to West Coast refineries.

Based on these assumptions, petroleum prices are projected to increase at 1.5 percent annually in real terms (more than 7 percent per year in current dollar terms) over the next 20 years. Table A-II shows projected prices for key petroleum products.

TABLE A-II

REPRESENTATIVE PETROLEUM PRICES
(¢/gal)

Year	Heating Fuel
1971	19.2
1976	41.3
1981	59.5
1986	85.9
1991	120.8
1996	170.0

Natural Gas

Since natural gas and petroleum products compete directly in many uses, future natural gas prices are related to increases in petroleum prices. However, natural gas is currently priced below petroleum products on a heat content basis. It is assumed that natural gas will achieve price parity with petroleum products by 1986. Gas prices will then parallel petroleum prices for the rest of the forecast period. This approach yields real price increases of 5.2 percent annually through 1986 and 1.5 percent per year thereafter. Future natural gas prices are shown in Table A-III.

TABLE A-III

AVERAGE NATURAL GAS PRICES
(¢/therm)

Year	Residential	Commercial	Industrial
1971	15.2	12.7	4.9
1976	26.9	23.9	15.7
1981	46.4	41.3	27.1
1986	80.0	71.2	46.7
1991	112.6	100.2	65.7
1996	158.5	141.1	92.6
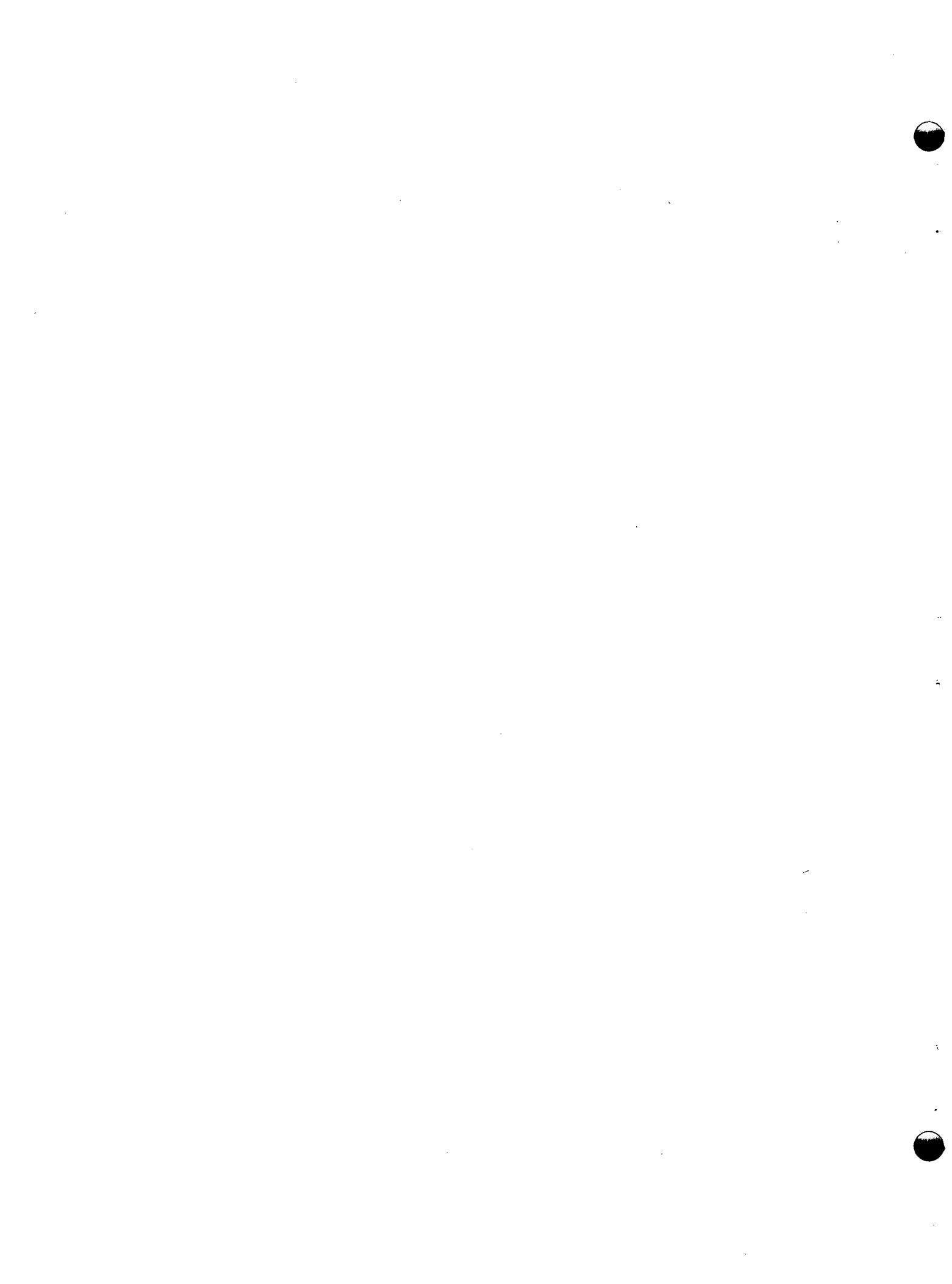
APPENDIX B

ANNUAL EQUIVALENT COST FORMULA

In performing economic cost analyses of geoheat systems for agribusiness as compared to conventional fuels currently in use, it became evident that price escalation of conventional fuels greatly exceeded inflation rates for well drilling, equipment purchase and installation, operating and maintenance costs. Research of available material indicated only superficial treatment of inflation rates in annual cost techniques. Efforts have been made to show how inflation lowers the value of present worth calculations or increases future costs in terms of today's dollars which would consider both the cost of capital and forecasted inflation rate based on several years of historical data. It is obvious that escalating costs could be calculated for each year over the life of an investment alternative, each cost discounted at the cost of capital to a present value, and then stated in the form of average annual cost equivalent. These calculations, however, would be extremely cumbersome particularly when dealing with long-lived wells and many components or subsystems with varying lives and repair or replacement frequencies.

In many cases, the attitude of economic analysts is simply that all alternatives are inflating at a similar rate and therefore the inflation factor can be ignored, since any decision which selects the best alternative in terms of today's dollars will also be the optimum choice in later years even though all costs may be inflated. Additionally a rate of inflation is nearly impossible to forecast. However, in this case the inflation rates of alternatives which provide energy are drastically different. Therefore, a method was necessary to provide a means of portraying these differences as accurately as possible. The following annual equivalent cost formula was developed which considers the cost of capital or rate of return together with a predictable inflation rate and selected optimum alternative. The formula can be used as a part of any conventional annual cost model.

Consider some annual cost factor in a typical annual cost-model that begins as an annual cost of $1,000 at the end of year one and inflates at a rate of 10 percent per year in the form of a geometric progression. Annual cash flows for a five-year period would be as follows:

	1000	1100	1210	1331	1464.1

Let $1,000 = a, let the inflation rate 10 percent annually = t, then:

	a	$a(1+t)^1$	$a(1+t)^2$	$a(1+t)^3$	$a(1+t)^4$

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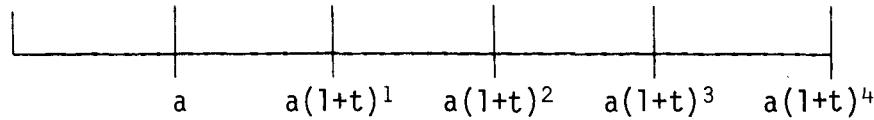
and the present worth (P) for an assumed cost of capital of 8 percent compounded annually (i) is:

$$P = a\frac{1}{(1+i)^1} + a\frac{(1+t)^1}{(1+i)^2} + a\frac{(1+t)^2}{(1+i)^3} + a\frac{(1+t)^3}{(1+i)^4} + a\frac{(1+t)^4}{(1+i)^5}$$

where $\frac{1}{(1+i)^n}$ is the present worth factor Pwf. Let n - number of interest periods (years in this case),

$$\text{then } P = \sum_{x=1}^{n} a(1+t)^{x-1} \frac{1}{(1+i)^x}$$

$$= \sum_{x=1}^{n} a\frac{(1+t)^{x-1}}{(1+i)^x} = \frac{a}{(1+i)} \sum_{x=1}^{n} \left(\frac{1+t}{1+i}\right)^{x-1}$$

$$\left[\text{note that: } a + ar + ar^2 + ar^3 + \ldots + ar^{n-1} = a\left(\frac{r^n-1}{r-1}\right) \right]$$
where r = constant.

$$\therefore \frac{a}{(1+i)} \sum_{x=1}^{n} \left(\frac{1+t}{1+i}\right)^{x-1} = \frac{a}{(1+i)} \left[\frac{\left(\frac{1+t}{1+i}\right)^n - 1}{\left(\frac{1+t}{1+i}\right) - 1} \right]$$

then to find the annual equivalent cost (A) considering inflation:

annual cost = present cost x capital recovery factor

$$A = P \times crf$$

$$A = P\left[\frac{i(1+i)^n}{(1+i)^n-1} \right]$$

$$A = \frac{a}{(1+i)} \left[\frac{\left(\frac{1+t}{1+i}\right)^n - 1}{\left(\frac{1+t}{1+i}\right) - 1} \right] \frac{i(1+i)^n}{(1+i)^n-1}$$

simplifying

$$A = \frac{a}{(1+i)} \left[\left[\left(\frac{1+t}{1+i}\right)^n - 1\right] \left[\frac{1+i}{(1+t) - (1+i)}\right] \right] \left[\frac{i(1+i)^n}{(1+i)^n - 1} \right]$$

$$A = \frac{a}{t-i} \left[\left(\frac{1+t}{1+i}\right)^n - 1\right] \left[\frac{i(1+i)^n}{(1+i)^n - 1} \right]$$

Adopting the notation used by the American Telephone and Telegraph Company in their text Engineering Economy, second edition, 1963, for purposes of standardization, as follows:

To find:	Given:	Notation:
Future value	Present value	$(f/p)_n^i$
Present value	Future value	$(p/f)_n^i$
Fugure value	Annuity of Amount A	$(f/a)_n^i$
Amount of Annuity A	Future value	$(a/f)_n^i$
Present value	Annuity of Amount A	$(p/a)_n^i$
Amount of Annuity A	Present value	$(a/p)_n^i$

where i is the interest rate per interest period and n is the number of interest periods,

the formula becomes:

$$A = \frac{a}{t-i} \left[(f/P)_n^t (P/f)_n^i - 1 \right] (a/P)_n^i \quad \text{and can be easily calculated}$$

using compound interest tables.

Using the initial values in this example:

$$A = \frac{1000}{.10 - .08} \left[(1.611)(.6806) - 1 \right] (.2505) = \$1,207.99$$

the average annual equivalent cost.

It should be noted when i = t the expression becomes $\frac{0}{0} \to$ undefined.

$$\cdot\; \lim_{i \to t} \; \left(\frac{1}{1+i}\right) \frac{\left[\left(\frac{1+t}{1+i}\right)^n - 1 \right]}{\left[\left(\frac{1+t}{1+i}\right) - 1 \right]}$$

$$= \lim_{i \to t} \; \left(\frac{1}{1+i}\right) \left[\frac{\left[\left(\frac{1+t}{1+i}\right) - 1 \right] \left[\left(\frac{1+t}{1+i}\right)^{n-1} + \left(\frac{1+t}{1+i}\right)^{n-1} + \dots + 1 \right]}{\left(\frac{1+t}{1+i}\right) - 1} \right]$$

$$= \lim_{i \to t} \left(\frac{1}{1+i}\right) \left[\left(\frac{1+t}{1+i}\right)^{n-1} + \left(\frac{1+t}{1+i}\right)^{n-2} + \ldots + 1\right]$$

$$= \lim_{i \to t} \left(\frac{1}{1+i}\right) \left[\left(\frac{1+i}{1+i}\right)^{n-1} + \left(\frac{1+i}{1+i}\right)^{n-2} + \ldots + 1\right]$$
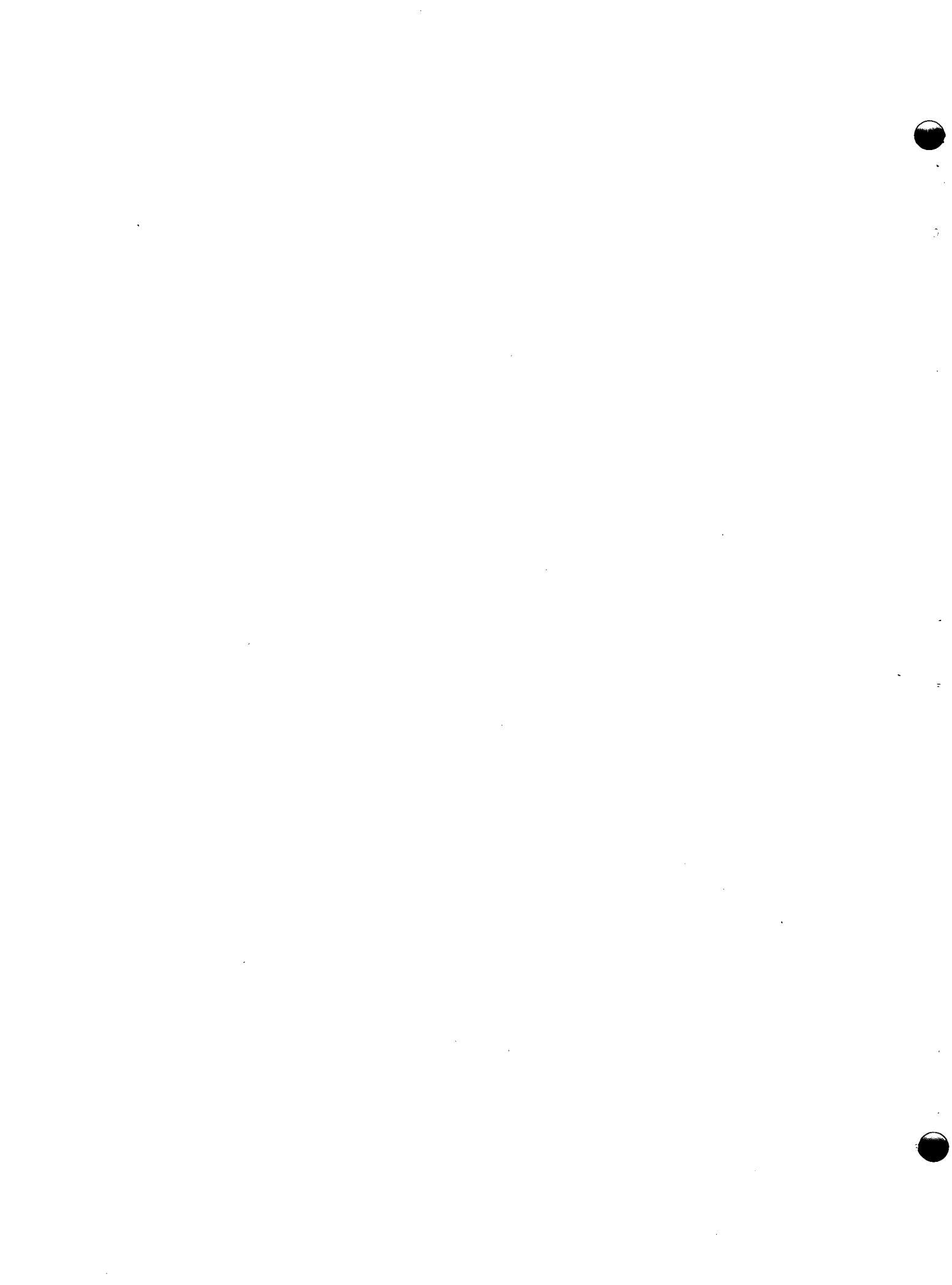
APPENDIX C

POTENTIAL FOR GREENHOUSE DEVELOPMENT
IN THE KLAMATH BASIN BY SUBAREA

The potential for the greenhouses to be used for specific crops will be stated. However, alternate crops must be considered for uses when competition and/or marketing factors make a specific crop unprofitable. Tree seedlings appear to be the most attractive crop at this time. The following section will describe their potential in detail.

Klamath Falls/North Altamont/Pelican City Subarea

This subarea is the most heavily populated of the six. A 15-acre greenhouse complex could be located in the City Industrial Park adjacent and west of the OIT campus. Plentiful supplies of water at temperatures of 194°F are known to be producing from 1,800 feet at OIT and the hospital wells. The area between OIT and Wocus has sufficient room for the industry but is untested for geothermal resources. Cold groundwater supplies are not in good supply but a city water main could be extended from Klamath Falls to the site.

The Old Fort Road area appears to have potential for both hot and cold water but 15-acre site locations are not available.

The Lake Ewauna to Summers Lane area is heavily populated and few 15-acre sites would be available. Water temperatures are not as high as in the OIT area, nor would the quantities be as great.

Any location in this subarea would be close to a plentiful labor force, good transportation facilities and a multiple crop market. Crop types could be foliage plants, potted flowers, cut flowers, tree seedlings, vegetables or a combination of any or all crops.

South Altamont/Miller Hill Subarea

Many areas have available land for a 15-acre site in this subarea. Water temperatures of 140°F would be sufficient for greenhouses but there may be insufficient quantities of both hot and cold water for greenhouse purposes.

Cold water is highly mineralized in certain portions of this area and will need to be carefully evaluated before being used for irrigation of valuable crops.

The most promising location could be east of Midland in the Miller Hill area ranging north-northwesterly to the Klamath River. Shallow cold-water wells have better water quality than those deeper than 260 feet. Chemical analyses would be recommended for both hot- and cold-water supplies and pumping tests should be made to establish quantities.

Any location in this subarea would be close to a labor force and transportation. Crop types could be the same as for the Klamath Falls/ North Altamont subarea.

Klamath Hills/Spring Lake Valley Subarea

A well-known geothermal zone is in this area at shallow depths and with plentiful hot-water supplies. The known area ranges in a narrow band along the southwest border of the Klamath Hills. Several sites are available for 15 or more acres of greenhouses each. One such enterprise is planning to begin construction during mid to late summer, 1977. This will be on the Jack Liskey Ranch and their primary crop will be tree seedlings. Good quality cold water for irrigation may be difficult to obtain on the sites and it may be necessary to pipe it in from another area.

The labor force to care for the greenhouses would be several miles from the site. Access to highway transportation is good.

Crop types could be the same as for the Klamath Falls/North Altamont subarea.

Olene Gap/Poe Valley Subarea

Several hot springs emerge into Lost River at Olene Gap. However, locations of building sites which are assessable are not available adjacent to the spring area. Ranging south-southwesterly from the Gap are plentiful greenhouse sites for 15-acre complexes.

This area which ranges as far south as Nuss Lake has high well gradients, and, although no deep wells have been drilled, it appears that resources would be available. Some cold-water wells south of the Gap are good producing wells of good quality but some are high in sodium. Chemical content should be evaluated before being used for irrigation.

Only two small areas along the North Poe Valley Road give evidence of geothermal resources. Each area is large enough for a 15-acre site.

All potential locations within this subarea are distant from labor forces and transportation. Tree seedling crops could be grown with a small labor force and easily transported to the planting sites.

Merrill/Malin Subarea

The area along the west flank of Stukel Mountain gives indications that sufficient geothermal resources are available at less than 1 km of depth. The same is true of a larger area northeasterly of Merrill. Each has sufficient area for one or more 15-acre greenhouse industries. Three smaller and more isolated areas west and south of Merrill show geothermal potential but are very isolated with limited area and access. Cold-water supplies appear adequate.

Greenhouses could be located in any of the areas mentioned. Potential labor forces appear inadequate. Growing tree seedlings would be the better crop, but foliage plants could also be grown.

Keno/Klamath River Subarea

The only evidence of geothermal resources in this subarea is within a populated hilly subdivision and on the flood plains of the Klamath River. Other subareas indicate better potentials for geothermal resources and with better access to labor forces and transportation facilities.

Langell Valley Subarea

The best potential greenhouse site for this subarea would be at the Turner Hot Spring location. A good (40 gpm) hot-water flow could be successfully utilized at the spring and adjacent areas show good thermal gradients. Plentiful supplies of cold water of good quality are available.

Langell Valley is distant from any labor force and transportation lines. Tree seedlings would probably be the best crop for the area.

Sprague River Subarea

This subarea has no proven potential for geothermal resources and is distant from a labor force and transportation lines. Other subareas show better potential for greenhouse industries.

APPENDIX D

ORGANIZATIONS CONTACTED

The following organizations cooperated in providing
data and background information during the course
of this study. Their assistance is gratefully
acknowledged.

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Food Processors

Amalgamated Sugar Company
Nyssa, Oregon
    Fred Franz
    Nelson C. Hiner

American Fine Foods, Inc.
Payette, Idaho
    Ron Schoen

Eastern Oregon Farming Company
Irrigon, Oregon
    Robert Lamb

Newhall Land and Farming Company
Dixon, California

Ore-Ida Foods, Inc.
Ontario, Oregon
    Bob Pederson
    Robert W. Rolf
    James W. Linford
    Jack Collins

Western Polymer Corporation
Tulelake, California
    Jim Aslett
    Maurene Ehlers

Equipment Manufacturers

Bert Farnes Company
Portland, Oregon
    Larry Paulus

Brod and McClung
Portland, Oregon
    Chuck Ingham

E. S. Constant Company
Portland, Oregon
    Ron Hoover

Interstate Pump Company
Klamath Falls, Oregon
    Lee Campbell

Equipment Manufacturers (cont.)

Johns-Mansville
San Francisco, California
    Howard Harvey

Johnson Controls
Portland, Oregon
    John Green

Proctor and Schwartz
San Jose, California
    Fred L. Wietersen

Roland Hardle Construction Company
Bend, Oregon

Sage Cable Company
Sage Pipeline, Inc.
Gold Hill, Oregon
    Walter Brotherton

Others

Broadlands Lucerne Company, Ltd.
Rotorua, New Zealand
    D. N. Pirrit

Bill Burrows
Rotorua, New Zealand

FJARHITUN, Ltd.
Reykjavik, Iceland
    Karl Omar Jonsson
    Ingolfur Adalsteinsson

National Energy Authority
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    Gylfi Petursson

Oregon Department of Energy
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Reykjavik, Iceland
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Tulelake, California
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        Ken Baghott

Comprehensive Planning Program
Vale, Oregon
        Bill Clark

Klamath County Economic Development Association
Klamath Falls, Oregon
        Tom Lund

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