Gas Extraction Systems for Geothermal Power Plants

2006

Steam jet/vacuum hybrid system by Gardner Denver Nash at a U.S. Geothermal Power Station

DISCLAIMER

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

DISCLAIMER

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

Two-stage Gardner Denver Nash steam ejector system at Santa Fe Geothermal Plant

Sacramento Municipal Utility District uses Gardner Denver Nash steam-jet/vacuum pump hybrid system

Table of Contents

Gardner Denver Nash – A Long History in Engineered Vacuum Systems	1
Helping Your Project Succeed	2-3
Factors Affecting Design Choices	3-5
Facts and Figures	5
Costs & Savings Examples	6-7
Successful Installations	8-15
Upgrades and Service	16
Appendix	16
Sample Schematics	17-20
Pictures of Gardner Denver Nash Installations	Covers

A Long History in Vacuum Systems

Gardner Denver Nash carries forward geothermal power experience that dates from the late 1950's and early 1960's. During that period, engineers of the Elliot Company devoted intensive study to pioneering the design and sizing of condenser gas extraction systems for the Geysers project in California.

When Elliot left the steam-jet ejector business in the mid-seventies, several of these key engineers founded their own firm under the name of Kinema, Inc., to continue the design and production of steam-jet ejector systems.

The Nash Connection

During the 1980's, The Nash Engineering Company began working with various ejector manufacturers to combine ejectors with Nash vacuum pumps into what is commonly called "Hybrid Systems". In order to handle this work with unified engineering and total system responsibility, Nash acquired Kinema, Inc. as a wholly-owned subsidiary in 1986.

The elmo Connection

During the 1990's Siemens elmo began offering Hybrid systems for geothermal gas extraction.

In 2002 Nash and elmo merged, forming a new company called nash_elmo. nash_elmo continued to offer hybrid sys-

tems to the geothermal power industry using all available technologies.

In 2004 nash_elmo was acquired by Gardner Denver and became NASH, Liquid Ring Pump Division of Gardner Denver. We continue our commitment to provide gas extraction systems that meet or exceed performance requirements of geothermal power plants around the world.

The Gardner Denver Nash Commitment

Gardner Denver Nash is committed to one endeavor: the design and development of the best vacuum and compressed gas technology in the world. We devote all our energies, all of our investment, and all of our research and development activities toward this goal.

Gardner Denver Nash is committed to providing gas extraction systems that meet or exceed performance specifications for geothermal power plants around the world.

The performance and reliability of Gardner Denver Nash systems have become worldwide standards against which the products of other manufacturers are measured.

Gardner Denver Nash's geothermal experience will help your project succeed

Superior design capabilities, highest quality, and most efficient equipment for extracting non-condensable gases from your condensers are critical for your plant's on-line operation and efficiency.

Your entire plant depends on vacuum

The condenser gas extraction systems must operate continuously. When any part of these systems fail for any reason, your plant's power output is lost.

Inability to handle the non-condensable load can cause the turbine to trip off-line with a corresponding loss of power and saleable electricity. You need the most reliable gas extraction system you can find.

Efficiency

Excessive steam consumption by the extraction systems can shorten the life of your field prematurely. The argument for the most efficient extraction system soon becomes obvious. In addition, the energy required for these extraction systems is not available as saleable power output, and thus, imposes an immediate economic loss.

Flexibility

Despite all efforts to predict and to control their behavior, geothermal fields are subject to the whims of nature. The amount and composition of non-condensable gases in the steam can change. So can steam pressure. Drilling more wells may remedy some deficiencies, but their characteristics cannot be predicted with certainty. Even cooling water temperature and availability are subject to change at some locations. All of these possibilities complicate the tasks of selecting and designing the right systems and equipment. The gas extraction systems must be designed to be flexible enough to adapt to changing site conditions.

Expert engineering pays off

The success that Gardner Denver Nash has achieved in this environment of shifting requirements is based on many years of engineering and application experience. We have seen what can happen at geothermal plants, and we have learned the most effective and economical ways to deal with the need for Reliability, Efficiency, and Flexibility. We apply this experience when we do the original design work and also when we modify systems in response to changed conditions.

Meeting your specifications

When we prepare our initial proposals, we base our calculations on rigorously honest appraisals and assumptions. As a

result, when Gardner Denver Nash installations go into service turbine backpressure meets or exceeds specifications.

Controlling costs

We offer you a realistic way to control costs. We can supply a number of vacuum systems to meet a given set of requirements. Although all of them will perform to specifications, some will cost far less to purchase and to install. Others will utilize steam, cooling water, and electric power more efficiently. As might be expected, the choices that conserve the most energy tend to cost more; but they will normally provide fast payback on the added investment. The number of possible combinations makes selecting the best one a complicated process — one that will be influenced by your own individual situation.

When you let us know your financial objectives, we will propose a system that will meet those objectives and enable you to plan your budgets with confidence. We will balance initial costs against low utility costs and low maintenance costs at the point you select. Gardner Denver Nash then provides you with the necessary commercial and technical information to make the most informed decision.

Performance

Gardner Denver Nash equipment performs to specifications, with a reliability unequaled in the field. The steam-jet ejectors, condensers, vacuum pumps and controls that we assemble for your system are designed and built to operate efficiently for years without interruption under the actual conditions you will experience at your plant.

Two-year warranty

Gardner Denver Nash protects you with a two-year warranty that covers all equipment components and the entire system.

You get the best service

Wherever in the world your plant may be located, Gardner Denver Nash delivers fast, skilled technical help. Our trained engineers will be present at startup and commissioning to make sure that all of our systems perform as they should. We will assist in training your operations staff so they can become totally familiar with the workings of our Gardner Denver Nash extraction systems.

After the plant has been operating for a while, we will visit and help diagnose any problems that may have shown up. And we will respond immediately to any emergency. This is all possible because of the Gardner Denver Nash global organization.

Geothermal field changes

Because the energy source of a geothermal power plant seldom remains constant over the years, your power station's operating efficiency may decline for any one of many reasons. We can often suggest modifications in our gas extraction systems that will restore optimum power and efficiency to the generating unit.

Our vacuum specialists can make the necessary measurements to evaluate your operating conditions without shutting

down or interrupting electric power output. They will be able to tell you what modifications will be advantageous to you. Sometimes, all that is necessary may be a simple change, such as control setting. If, however, equipment modification or replacement will be involved, our engineers will let you know in advance how much it will cost. They will give you a reliable prediction of the operating improvement you can expect to achieve. Thus, you will have all the information you need to calculate a payback time and to arrive at a sound decision about the desirability and the timing of a possible upgrade.

Factors that affect system design choices

Condenser gas extraction systems for geothermal plants perform the same function as condenser exhausters in fossil-fueled generating stations; but they are quite different. Because steam from geothermal fields contains such great quantities of non-condensable gases compared with what is found in a closed-circuit boiler-water system, capacities must be far larger. The amount of gas to be handled is never exactly predictable, and it is not a clean mixture. Among other mineral compounds, it contains carbon dioxide and sulfides, which make it corrosive. It often carries silica, which precipitates out and builds up in piping and equipment.

System design begins with the best available prediction of how much CO₂ and other non-condensable gases the steam from the field will bring into the turbine. The temperature, quality, and cost of available cooling water will affect system design decisions. So will any restrictions on the disposal of polluted water.

The system components

All gas extraction systems require condensers. While non-condensables from the main condenser are being compressed to atmospheric pressure, a substantial amount of the moisture they carry becomes condensable. It is cooled between stages of compression with inter-condensers and disposed of as a liquid. Both direct-contact barometric condensers and shell-and-tube surface condensers are used in gas extraction systems for geothermal plants. The choice of condenser type depends on environmental considerations.

While direct-contact condensers are more efficient and less costly, they do mix cooling water with geothermal steam. These systems utilize cooling towers for water recirculation, and may re-inject effluent water back into the earth to prevent pollution.

While surface condensers cost more, they keep clean cooling water separate from geothermal condensate. Pollution problems and cooling tower maintenance are minimized.

Steam-jet ejectors are the most widely used of all gas-compressing devices for gas extraction at geothermal plants. They are relatively inexpensive. They use the field steam directly as their motive energy source, and they have no moving parts. The main disadvantage of steam-jet ejectors is their inflexibility to meet widely changing pressure or flow requirements and their high consumption of valuable steam.

Gardner Denver Nash vacuum pumps are motor-driven, and they use this mechanical energy efficiently. Their operating characteristic enables them to adapt to changes in pressure and flow requirements.

Gardner Denver Nash is the world's leading supplier of vacuum pumps used for condenser exhausting at fossil-fueled power plants. But, the huge quantities of both condensable and noncondensable vapors that must be handled at geothermal plants would require many large vacuum pumps, which would be unattractive from a capital investment standpoint. A good engineering and economic compromise is to use ejectors in the higher vacuum ranges where a large amount of condensables exist, and to use Gardner Denver Nash vacuum pumps in the middle-to-lower vacuum ranges, where those condensables have been reduced to condensate. This is why the vacuum pumps are staged with steam-jet ejectors and called "hybrid systems".

Turbo-compressors may be driven by separate steam turbines, through speed-increasing gears by separate motors, or by the main turbines through auxiliary gear sets. They are relatively efficient in their use of energy. However, these high-speed machines are suitable primarily for clean, dry gas compression. They have not proven to be reliable for this

application without continuous, expensive and sophisticated preventative maintenance programs.

Geothermal gas extraction is a dirty, wet application. Yearly maintenance and repair costs of turbo-compressors rise steeply when they handle moisture-laden gas mixtures. Although elaborate precautions may be taken to prevent slugs of water from entering turbo-compressor inlets, such accidents do occur, and they cause catastrophic failures. Most engineers avoid recommending turbo-compressors for this application, and Gardner Denver Nash does not supply them for condenser gas extraction systems.

How the components are combined

First costs, operating costs, geothermal field management and environmental considerations all influence the selection of components and the ways they are combined to form a system.

In most cases, each main condenser will be served by two or more parallel trains of components to provide operating flexibility and redundancy. The sum of their capacities usually equals or slightly exceeds anticipated operating requirements. In the following discussions and illustrations, a single train of components is treated as the basic system, even though it may be only one of several trains serving a single condenser.

Whether the choice is made to use direct-contact barometric condensers or shell-and-tube surface condensers, the selection of other components can be made independently. As long as condenser fouling can be managed satisfactorily, both types perform equally well. Effluent control requirements determine the choice between the two. The extra cost of surface condensers must be justified by the value placed on a segregated cooling water system.

In the past, an all-jet system was the classic, most widely used condenser gas extraction system for geothermal power plants. Each of the three ejector stages is followed by a condenser, as more moisture can be condensed at each succeeding higher pressure. At an installation where the main condenser does not remove enough of the condensable vapor, the gas extraction system often includes a pre-condenser or gas cooler that reduces the vapor load to the first-stage ejector.

Over the last fifteen years, the Gardner Denver Nash "hybrid system" has gained acceptance as a more popular choice for gas extraction systems. These systems use far less energy than all-ejector systems and will help extend the life of each well. With a Gardner Denver Nash vacuum pump in place of the last stage ejector in a three-stage system, the steam savings pay for electric power to run the pump and leave a substantial extra margin of overall energy gain.

Still greater operating cost savings can be achieved by going to a two-stage hybrid system, with one initial ejector stage, and a large vacuum pump.

When you evaluate costs on a short-term basis, an all-ejector system invariably appears to be the best choice because of its low initial cost. However, when you calculate the sum of initial investment plus operating costs over longer and longer terms, including Gardner Denver Nash vacuum pumps in the system shows up as a better and better choice, delivering a high rate of return on the additional capital invested.

Another benefit that the hybrid systems afford is operating flexibility. If available steam pressure or other design parameters should change as the field matures, the inherent operating characteristic of liquid-ring vacuum pumps allows them to compensate for the changes. A hybrid system, thus, will adapt itself with fewer equipment modifications over the years.

Evaluating the tradeoffs

Comparisons in the following typical examples show how relative costs and savings of different system choices can be evaluated to form a basis for your informed decisions.

In these cases, we have assumed that direct-contact condensers will be used, and that the main condenser will also be direct-contact. A pre-condenser or gas cooler is therefore included as part of the gas extraction system. Turbine exhaust steam is assumed to contain 14% moisture. This variable affects the total quantity of cooling water utilized. That water will release dissolved air, which will add to the non-condensable load.

In Case 1, gas load from the main condenser to the gas cooler is assumed to consist of:

Air	290 kh/hr
Other non-condensables	4,040 kg/hr
Steam	16,057 kg/hr

Other assumptions:

Turbine exhaust pressure	126.67 mbarA
Drop across main condenser	2.5 mmHg
Drop across gas cooler	2.0 mmHg
Drop in piping and valves	3.9 mmHg

Steam cost	\$4.40/1000 kg
Electric power cost	\$0.04/kWhr
Operating time	8,700 hours/year

Each of the three options presented is sized for 50% of total capacity, so that two identical trains are needed to handle gases drawn from the main condenser. Option A is an all-ejector system. Option B is a three-stage hybrid system.

Option C is a two-stage hybrid system.

In Case 2, gas loading from the main condenser is assumed to consist of:

Air	290 kg/hr
Other non-condensables	8,080 kg/hr
Steam	23,982 kg/hr

All other assumptions are the same as those for the first case. The three options are the same as those for the first case, too, except that each train is sized for 25% capacity.

The low-cost option

In each of these two typical cases, Option A, the all-jet system, shows an attractively low initial investment. However, the annual operating costs are far higher than either of the other two cases.

The balanced option

Option B, the three-stage hybrid system, balances operating costs savings against initial investment.

The low operating cost option

Option C, the two-stage hybrid system has the lowest operating costs. The higher initial investment to gain this cost reduction, however, extends its payoff time considerably.

For Facts and Figures Related to Your Project

This brief summary of Gardner Denver Nash's engineering approach to geothermal power plant systems is backed up by volumes of technical calculations, operating cost analyses, and comparisons of alternate system choices.

The sheer bulk of this data prevents us from including all of it here. Our experience shows that each customer's systems and needs differ. We will be glad to review with you data that relates to your own project.

Contact the Gardner Denver Nash office nearest you or our Power Division headquarters in Elizabeth, PA:

700 McKeesport Road
Elizabeth, PA 15037-1864 USA
Tel: +1 412 384 3610
Fax: +1 412 384 4880
nash@gardnerdenver.com

Costs & Savings - Case 1

Option A

Option B

Option C

Cooling Water @ 35°C Max.

	Size	m ³ /hr	Rise
PX	60	398	9.5°C
XY	36	116	14°C
YZ	28	115	14°C
ZA	24	<u>107</u>	14°C
Each train		736	
736 x 2 = 1,472 m ³ /hr			

	Size	m ³ /hr	Rise
PY	60	398	9.5°C
YZ	28	115	14°C
ZP	24	<u>107</u>	14°C
		629	
Pump CL-2001	Z		
Each train		736	
636 x 2 = 1,272 m ³ /hr			

	Size	m ³ /hr	Rise
PZ	60	398	9.5°C
ZP	36	<u>116</u>	14°C
		514	
Pump 904-R2		<u>23</u>	
Each train		537	
537 x 2 = 1,074 m ³ /hr			

Cost of 6.55 barA Motive Steam @ \$4.40/1,000 kg

	Size	kg/hr
X	14x14	2,313
Y	10x10	2,313
Z	6x6	<u>2,313</u>
Each train		6,939
6,939 x 2 = 13,878 kg/hr		
\$4.40 x 13,878 = \$61.06/hr		
\$61.06/hr x 8,700 hr/yr		
= \$531,222/yr		

	Size	kg/hr
Y	14x14	2,313
Z	10x10	<u>2,313</u>
Each train		4,626
4,626 x 2 = 9,252 kg/hr		
\$4.40 x 9,252 = \$40.71/hr		
\$40.71/hr x 8,700 hr/yr		
= \$354,177/yr		

	Size	kg/hr
Z	14x14	<u>2,313</u>
Each train		2,313
2,313 x 2 = 4,626 kg/hr		
\$4.40 x 4,626 = \$20.35/hr		
\$20.35/hr x 8,700 hr/yr		
= \$177,045/yr		

Cost of Electric Power @ \$0.04/kWhr

0 kW
\$0

60 kW x 2 = 120 kW
\$0.04/kWhr x 120 = \$4.80/hr
\$4.80/hr x 8,700 hr/yr
= \$41,760/yr

174 kW x 2 = 348 kW
\$0.04/kWhr x 348 = \$13.92/hr
\$13.92/hr x 8,700 hr/yr
= \$121,104/yr

Operating Cost - Steam & Electric Power

\$531,222/yr
Operating Cost Savings (base)

\$395,937/yr
Operating Cost Savings \$135,285/yr

\$298,149/yr
Operating Cost Savings \$233,073/yr

Capital Cost

\$250,000
Payoff Time: (base)
First Year Cost: \$781,222

\$575,000
Payoff Time: 2.4 years
First Year Cost: \$970,937

\$1,075,000
Payoff Time: 3.6 years
First Year Cost: \$1,373,149

Costs & Savings - Case 2

Option A

Option B

Option C

Cooling Water @ 35°C Max.

	Size	m ³ /hr	Rise
PX	60	340	7.8°C
XY	42	160	14°C
YZ	30	136	14°C
ZA	24	125	14°C
Each train		761	
761 x 4 = 3,044 m ³ /hr			

	Size	m ³ /hr	Rise
PY	60	340	7.8°C
YZ	42	160	14°C
ZP	30	136	14°C
		636	
Pump CL-2001		9	
Each train		645	
645 x 4 = 2,580 m ³ /hr			

	Size	m ³ /hr	Rise
PZ	60	340	7.8°C
ZP	42	160	14°C
		500	
Pump 904-R2		32	
Each train		532	
532 x 4 = 2,128 m ³ /hr			

Cost of 6.55 barA Motive Steam @ \$4.40/1,000 kg

	Size	kg/hr
X	16x16	2,540
Y	10x10	2,540
Z	6x6	2,540
Each train		7,620
7,620 x 4 = 30,480 kg/hr		
\$4.40 x 30,480 = \$134.11/hr		
\$134.11/hr x 8,700 hr/yr		
= \$1,166,757/yr		

	Size	kg/hr
Y	16x16	2,540
Z	10x10	2,540
Each train		5,080
5,080 x 4 = 20,320 kg/hr		
\$4.40 x 20,320 = \$89.41/hr		
\$89.41/hr x 8,700 hr/yr		
= \$777,867/yr		

	Size	kg/hr
Z	16x16	2,540
Each train		2,540
2,540 x 4 = 10,160 kg/hr		
\$4.40 x 10,160 = \$44.70/hr		
\$44.70/hr x 8,700 hr/yr		
= \$388,890/yr		

Cost of Electric Power @ \$0.04/kWhr

0 kW
\$0

87 kW x 4 = 348 kW
\$0.04/kWhr x 348 = \$13.92/hr
\$13.92/hr x 8,700 hr/yr
= \$121,104/yr

259 kW x 4 = 1,036 kW
\$0.04/kWhr x 1,036 = \$41.44/hr
\$41.44/hr x 8,700 hr/yr
= \$360,528/yr

Operating Cost - Steam & Electric Power

\$1,166,757/yr
Operating Cost Savings (base)

\$898,971/yr
Operating Cost Savings \$267,786/yr

\$749,418/yr
Operating Cost Savings \$417,339/yr

Capital Cost

\$500,000
Payoff Time: (base)
First Year Cost: \$1,666,757

\$1,175,000
Payoff Time: 2.5 years
First Year Cost: \$2,073,971

\$2,150,000
Payoff Time: 4.0 years
First Year Cost: \$2,899,418

Our History of Successful Installations

CUSTOMER	USER/Plant	MW RATING	YEAR SOLD
1. Ecolaire	NCPA California Geysers	106	1979
2. Ecolaire	PSNM-BACA Ejectors Now Installed At CFE-Los Azuferes, Mexico		1980
3. SMUD	SMUD Geo. #1 California Geysers	72	1981
4. Ecolaire	State of California	55	1982
5. Ecolaire	OXY Geothermal (Santa Fe) California Geysers	40	1982
6. Ecolaire	Utah P&L Bundell 1 Roosevelt Hot Springs	20	1982
7. DeLaval	Heber Geothermal California	45	1982
8. PG&E	California Geysers	113	1982
9. Reactor Controls Inc.	State of California, South Geyser		1983
10. SEC Pacific Trading Corp.	Yang Ba Jine Geothermal Tibet	3	1985
11. DeLaval	Heber-Binary	47	1985
12. Beowawe Geothermal	Beowawe Geothermal Elko Nevada	15	1986
13. State of California	Bottle Rock California Geysers Upgrade of Item 4	55	1986
14. Desert Power Company	Salton Sea Unit #3 California	50	1987
15. FUJI Electric	Oxbow Geothermal Nevada	50	1987
16. Freeport Geothermal	Bear Canyon California Geysers	20	1987
17. MHI	GEM Unit #2 East Mesa California	18	1988
18. MHI	GEM Unit #3 East Mesa California	18.5	1988
19. Ecolaire	Mission Power - Navy 1 COSO Hot Springs California	2x25	1988
20. Ecolaire	Mission Power BLM East COSO Hot Springs California	2x24	1988
21. Ecolaire	Mission Power BLM WEST COSO Hot Springs California	28	1988
22. Ecolaire	Mission Power Navy II COSO Hot Springs California	3x25	1988
23. Dow Engineering	Magma Power	?	1988

We include a listing of our recent projects in this section. If you would like to have more information about the choices involved with these jobs or about their technical features, we will be glad to describe them to you.

NC Capacity	SUCTION PPH	CONFIGURATION Pressure In.HGA	COMMENTS
1,830	1.76	ECEC	60/40
28,010	3.00	EBEB	4-25% - 1st Stages 2-50% - 2nd Stages
3,900	1.16	ECEC (VP)	3-50% - 1st Stages 2-100% - 2nd Stages 3-50% - 3rd Stages NASH CL-3003 VP
9,022	3.32	ECEC	33a% Elements
13,513	2.90	ECEC	2-50% - 1st Stages 1-100% - 2nd Stages
12,130	2.61	ECEC	75/50/25 Elements
642	2.48	EC (VP)	3-50% Trains NASH CL-402 VP
20,492	3.40	EBEB	2-50% - 1st Stages 1-100% - 2nd Stages
2,215	1.85	ECEC	3-50% Elements
730	2.25	BE	Water Operated Eductor w/114" Turbine Condenser
3,157	3.0	ECEC	To be used in conjunction with Number 7
3164/2949	0.8-1.25	EBEB (VP)	Two stage Hybrid with A 1st Stage Ejector and CL-1003 VP
23,417	3.32	C	After-Condenser
80% 4581 60% 3666	1.26/1.85	ECECEC (LP/HP)	80/60/40% Trains. Dual 1st Stage for 2 Pressure Main Condenser Side with Pre-Cooler on HP Side
10,398	0.55/1.005	EBEBE	Three 50% Element Dual First Stages for 2 Pressure Main Condenser
2,434	1.36	ECEC	Four Duplicate Units Three Element 40/35/25% See #41 Upgraded in 1992
3,300	2.6	EBEBVP	Two 100% First and Second Stage Ejector with 200% Barometric Inter- Condensers and Two 100% CL-2002 VP
3,300	2.6	EBEBVP	Two 100% First and Second Stage Ejector with 200% Barometric Inter- Condensers and Two 100% CL-2002 VP
10,000	2.6	ECEC	Two 100% Elements 2 Units
8,800	2.1	ECEC	Two 100% Elements 2 Units
14,800	2.1	ECEC	Two 100% Elements 1 Unit
10,000	2.1	ECEC	Two 100% Elements 3 Units
215	1.0	EC (VP)	2-100% 1st Stages, 10x10,

CUSTOMER	USER/Plant	MW RATING	YEAR SOLD
24. Ben Holt Company	Utah Municipal Power Unit #2 Cove Fort	8	1989
25. Santa Fe Geothermal	Santa Fe Geothermal (OXY) California Geysers Upgrade of Item 5	40	1989
26. Toshiba	National Power Corp. of The Philippines Tiwi Plant Unit 1	55	1991
27. Toshiba	National Power Corp. of The Philippines Tiwi Plant Unit 2	55	1991
28. Toshiba	National Power Corp. of The Philippines Tiwi Plant Unit 5	55	1991
29. Toshiba	National Power Corp. of The Philippines Tiwi Plant Unit 6	55	1991
30. Electricorp	Electricorp Waireki "A" Unit G7 New Zealand	11.2	1991
31. Electricorp	Electricorp Waireki "A" Unit G8 New Zealand	11.2	1991
32. Electricorp	Electricorp Waireki "A" Unit G9 New Zealand	11.2	1991
33. Electricorp	Electricorp Waireki "A" Unit G10 New Zealand	11.2	1991
34. MHI	National Power Corp. of The Philippines Cawayan Station	20	1992
35. MHI	National Power Corp. of The Philippines Botong Station	20	1992
36. FUJI	National Power Corp. of The Philippines Nasuji Station	20	1992
37. FUJI	National Power Corp. of The Philippines Okoy Station	20	1992
38. FUJI	National Power Corp. of The Philippines Sogongon I	20	1992
39. FUJI	National Power Corp. of The Philippines Sogongon II	20	1992

NC Capacity PPH	SUCTION Pressure in.HGA	CONFIGURATION	COMMENTS
9,341	2.15	EC (VP)	200% IC 2-50% 1st Stage 18x18 Ejectors Surface Condenser and CL-4003 VP
4,303	1.5	EC (VP)	Retrofit 1 Train of Hybrid System 16x16 1st Stage 2-NASH CL-4003 VP
25,000	4.0	EB (VP)	Retrofit of Existing Steam Ejector System to NASH Hybrid 36x30 1st Stage and 904T VP
25,000	4.0	EB (VP)	Retrofit of Existing Steam Ejector System to NASH Hybrid 36x30 1st Stage and 904T VP
25,000	4.0	EB (VP)	Retrofit of Existing Steam Ejector System to NASH Hybrid 42x36 1st Stage and 904T VP
25,00	4.0	EB (VP)	Retrofit of Existing Steam Ejector System to NASH Hybrid 42x36 1st Stage and 904T VP
2,361	1.98	EBEBEB	Retrofit of Existing Steam Ejector System to 3-37% Elements 12x10 First Stage All Ejector System
2,361	1.98	EBEBEB	Retrofit of Existing Steam Ejector System to 3-37% Elements 12x10 First Stage All Ejector System
2,361	1.98	EBEBEB	Retrofit of Existing Steam Ejector System to 3-37% Elements 12x10 First Stage All Ejector System
2,361	1.98	EBEBEB	Retrofit of Existing Steam Ejector System to 3-37% Elements 12x10 First Stage All Ejector System
6,667	3.30	EB (VP)	Two Stage Hybrid with 18x18 First Stage Ejector, Barometric Condenser & 904L2 Vacuum Pump with a 10x10 Back-Up Ejector
21,892	3.59	EB (VP)	Two Stage Hybrid with 36x36 First Stage Ejector, Barometric Condenser & 904T2 Vacuum Pump with a 16x16 Back-Up Ejector
5,225	3.42	EB (VP)	Two Stage Hybrid 18x18 First Stage Ejector, Barometric Condenser & 904L2 Vacuum Pump with A 10x10 Back-Up Ejector
5,225	3.42	EB (VP)	Two Stage Hybrid 18x18 First Stage Ejector, Barometric Condenser & 904L2 Vacuum Pump with A 10x10 Back-Up Ejector
5,225	3.42	EB (VP)	Two Stage Hybrid 18x18 First Stage Ejector, Barometric Condenser & 904L2 Vacuum Pump with A 10x10 Back-Up Ejector
5,225	3.42	EB (VP)	Two Stage Hybrid 18x18 First Stage Ejector, Barometric Condenser & 904L2 Vacuum Pump with A 10x10 Back-Up Ejector

	CUSTOMER	USER/Plant	MW RATING	YEAR SOLD
40.	Calpine Corp. Upgrade #16	Bear Canyon California Geysers	20	1992
41.	Calpine Corp.	Westford Flats California Geysers, Upgrade Existing Unit	20	1993
42.	MHI	PLN/Darajat Indonesia	55	1993
43.	MHI	NPC/MAKBAN Philippines	20	1993
44.	MHI	NPC/MAKBAN Philippines	20	1993
45.	MHI	NPC/MAKBAN Philippines	20	1993
46.	MHI	NPC/MAKBAN Philippines	20	1993
47.	California Energy (COSO)	BLM East – Upgrade #20 USA	2x25	1994
48.	California Energy (COSO)	BLM West – Upgrade #21 USA	25	1994
49.	California Energy (COSO)	Navy 1 - Upgrade #19 USA	3x25	1994
50.	California Energy (COSO)	Navy 2 - Upgrade #22 USA	3x25	1994
51.	PG&E	Unit 17	82	1994
52.	NCPA	Unit 2	53	1994
53.	California Energy (COSO)	Navy 2 - Upgrade #22/50	3x25	1995
54.	PG&E	Unit 13	110	1995
55.	MHI	MT APO Philippines	48.7	1995
56.	Northern California Power Agency	NCPA Plant 1 – Unit 1 Geysers	53	1995
57.	Fluor Daniel/UNOCAL	SALAK – Indonesia	3x55	1995

NC Capacity	SUCTION PPH	CONFIGURATION Pressure In.HGA	COMMENTS
2,434	1.36	EC (VP)	Two SC-7 Vacuum Pumps to Replace 40% Second Stage Ejectors
2,434	1.36	EC (VP)	Two SC-7 Vacuum PUMPS to Replace 40% Second Stage Ejectors
5,188	3.72	EB (VP)	Two Stage Hybrid with Two 100% First Stage 24x24 Ejectors with Barometric Condensers Two 50% 904P-3 VP 16x16 Back-Up Ejector
1,521	3.3	EB (VP)	Two Stage Hybrid with 14x14 First Stage Ejector, Barometric Condenser & CL-2002 Vacuum Pump with a 8x8 Back-Up Ejector
1,521	3.3	EB (VP)	Two Stage Hybrid with 14x14 First Stage Ejector, Barometric Condenser & CL-2002 Vacuum Pump with a 8x8 Back-Up Ejector
1,521	3.3	EB (VP)	Two Stage Hybrid with 14x14 First Stage Ejector, Barometric Condenser & CL-2002 Vacuum Pump with a 8x8 Back-Up Ejector
1,521	3.3	EB (VP)	Two Stage Hybrid with 14x14 First Stage Ejector, Barometric Condenser & CL-2002 Vacuum Pump with a 8x8 Back-Up Ejector
32,000	2.1	ES (VP) COMP	Upgrade of Existing All Ejector System to A Hybrid. Added Two (2) 904T (VP) Discharging into a 904R Compressor
24,000	2.6	ES (VP) COMP	Upgrade of Existing All Ejector System to A Hybrid. Added 904R and P (VP), Discharging into a 904L1 Compressor
24,000	2.6	ES (VP) COMP	Upgrade of Existing All Ejector System to A Hybrid. Added 904T and P (VP), Discharging into a 904L1 Compressor
41,000	2.6	ES (VP) COMP	Upgrade of Existing All Ejector System to A Hybrid. Added Two (2) 904T and One (1) 904P Discharging into a 904R1 Compressor
5,500	2.3	EBEBEB	Revamp Existing 2 Stage to 3 Stage
1,740	1.76	ESES (VP)	Revamp Existing 2 Stage Jet System to 3 Stage Hybrid (SC-7)
48,000	2.6	VP	Replace Existing 904P2 with 904T2 Upgrade Capacity
2,624	2.2	ESES (VP)	Revamp 2 Stage Jet to 3 Stage Hybrid (SC-11)
9,000	2.3	EBEB (VP)	50% Ejector Elements 100% Liquid Ring Vacuum Pump with Back-Up Ejector Stage
1740	1.76	ESES (VP)	Revamp Existing 2 Stage Jet System to 3 Stage Hybrid (SC-7)
13183	2.05	EC (VP)	3 - 1st Stage Jets, 1-IC, 2-60% LRVF with Back-Up Jet (60%) -

	CUSTOMER	USER/Plant	MW RATING	YEAR SOLD
58.	Mercury Geothermal	Pohipi - New Zealand	55	1996
59.	Yankee Caithness	Steamboat Geothermal Plant Reno, NV	15	1996
60.	Oxbow Geothermal	Dixie Valley Upgrade of #15	50	1996
61.	GILBERT/CBE	Dieng Unit 1 Indonesia		1996
62.	SAI Geothermal	Berlin Geothermal El Salvador	2x27.5	1997
63.	FUJI	Svrtsegi, Iceland	30	1997
64.	Stone & Webster	Darajat II, Indonesia	70	1997
65.	Stone & Webster	Darajat III, Indonesia	70	1997
66.	FUJI	Wayang Windu	110	1997
67.	FUJI	Wayang Windu	110	1997
68.	FUJI	Hachijyo	3.3	1997
69.	MHI	Mindanao II	48.25	1997
70.	MHI	Nesjavellir, Iceland Unit 1	30	1997
71.	MHI	Nesjavellir, Iceland Unit 2	30	1997
72.	CAL Energy	Salton Sea, Unit 2		
73.	MHI	Miravalles III Costa Rica	27.5	1998
74.	MHI	Cerro Prieto IV Units 1-4 Mexico	4x25	1998
75.	NCPA (Northern California Power Agency)	Geysers #1	55	1998
76.	American Caribbean Intl.	Ahuachapan El Salvador		1999
77.	Stone & Webster	Region II Vulcan	34.5	1999
78.	Kingston Morrison	TIWI Philippines	85	1999
79.	Alstom	Tres Virgenes Mexico	10	1999
80.	Stone & Webster	Salton Sea, Unit 5	47.5	1999
81.	GLIMEX	Botoming Philippines		1999
82.	MHI	Nesjavellir, Iceland		2000
83.	MHI	Olkaria Kenya		2000
84.	Alstom	Geysers Units 5 & 6		2001
85.	Alstom	Los Azufres Units 13-16 Mexico	25	2001

NC Capacity PPH	SUCTION Pressure in.HGA	CONFIGURATION	COMMENTS
6861	2.87	ES (VP)	(904R2) Pumps 4-25% 1st Stages, 2-IC, (904L2) Includes Back-Up Ejectors/AC
4400	2.0	EB(VP)	Revamp Existing 2 Stage Ejector System to Hybrid (904L2)
6000	.55/1.0	EBEB (VP)	Replace 3rd Stage Jets with SC-11 LRVF
52161	4.0	EBEB	33a% Elements
1933	2.55	EBEB	2 Trains per Unit
13779	2.66	ECVP	2-50% Hybrid Trains 1-50% Ejector Train
16255	1.6	EBEBVP	2-75% Trains
16255	1.6	EBEBVP	2-75% Trains
16550	2.98	EBEBVP	2-50% Hybrid Trains 1-50% Ejector Train
16550	2.98	EBEBVP	2-50% Hybrid Trains 1-50% Ejector Train
1760	3.54	EBEB	100% Ejector Train
7927	2.53	EBEBVP	60/40% Ejectors / 100% VP
3934	5.61	VP	2x505 Vacuum Pump
3934	5.61	VP	2x505 Vacuum Pump
		ES	Back-Up Second Stage Ejector
5637		EBVP	
11592	3	EBVP	3x50% 1ST Stage Ejectors 2x50% Vacuum Pumps 50% Back-Up Ejector
		ESESES	2/012-3-0(SS)
3549	2.36	EBVP	018-2-OBP
		EBVP	
		EBVP	
		EBVP	
		EBEB	
2295	2.24	ECVP	100% Hybrid Train W Reinjection Compressor
		VP	2x50% Vacuum Pumps
		EBVP	
7190		EBVP	
		ECVP	3x50% Hybrid Trains per Unit

Upgrades & Service

If your existing geothermal plant is more than six or seven years old, it is very likely that its operation can be improved substantially by upgrading its condenser gas extraction systems. It is expected that components are susceptible to erosion, corrosion or damage in other mechanical ways. Geothermal plants, however, are candidates for upgrading for reasons not found in many other industries.

With the life span and output of a plant intimately associated with the condition and output of the steam field, operating conditions may change dramatically over time. The question then is "How to provide optimum performance within economic boundaries?"

Here at Gardner Denver Nash, we have been involved with the design of gas extraction systems since 1974. We are very familiar with the problems noted above, having designed and built both new and upgraded systems.

Four major areas for evaluation in an existing plant will include:

- Increased non-condensable gas flow.
- Declining steam field pressure.
- System flexibility.
- Economics.

We offer a service that will identify the impact of each of these items on your operations. By conducting a complete system survey, with no plant downtime, we can analyze the current level of performance and make recommendations for both short and long-term modifications. A few examples of our work include:

- Modifying systems for increased non-condensable gas flow (California Energy – COSO Area)
- Re-nozzling steam ejectors for declining steam pressures (Northern California Power Agency – Geysers Area)

- Converting an all steam jet system to a hybrid system by the addition of a vacuum pump to extend well life (Santa Fe Geothermal – Geysers Area)
- Redesigning the gas extraction system to dramatically reduce steam consumption by the first and second stage ejectors (Electricorp – Wairakei Area, New Zealand)
- Our vacuum system expertise and our long relationship with Geothermal Power Generation can result in significantly increased profits at your plant.
- Again, please call the Gardner Denver Nash office nearest you for more information.

APPENDIX

This document contains schematic representations and photographs of various systems supplied by Gardner Denver Nash. We will be happy to discuss any of these designs and how they can best serve your needs. Contact the Gardner Denver Nash office nearest you or our Power Division headquarters in Elizabeth, PA:

700 McKeesport Road
Elizabeth, PA 15037-1864 USA
Tel: +1 412 384 3610
Fax: +1 412 384 4880
nash@gardnerdenver.com

Three Stage Ejector System

Typical component arrangements for a three stage all-ejector system. At the top is a system with surface condensers. The middle system has direct-contact condensers. On the bottom, a direct-contact pre-condenser or gas cooler precedes the first ejector stage.

Three Stage Hybrid System

In these three stage hybrid systems, the last stage ejector and its condenser are replaced by a NASH liquid ring vacuum pump.

Two Stage Hybrid System

These are two stage hybrid systems. The liquid ring vacuum pump operates at a lower interstage pressure to do more of the work of gas removal than it would in a three stage system.

Two Stage Hybrid System

In each of these two stage hybrid systems, two NASH liquid ring vacuum pumps operating in parallel serve as the second stage.

First and Second stage steam jet system by Gardner Denver Nash at SMUD Geothermal Plant

Third stage vacuum pump by Gardner Denver Nash at SMUD Geothermal Plant

Gardner Denver Liquid Ring Pump Division

9 Trefoil Drive
Trumbull, CT 06611
phone: 1 800 553 NASH
+ 1 203 459 3900
fax: + 1 203 459 3988
email: nash@gardnerdenver.com
www.GardnerDenverNash.com

Australia, Smithfield, NSW
Gardner Denver Nash Australia Pty. Ltd.

Germany, Nürnberg
Gardner Denver Nash
Deutschland GmbH

Singapore
Gardner Denver Nash Singapore

Brazil, Campinas, São Paulo
Gardner Denver Nash Brasil Industria
e Comercio de Bombas Ltda.

Japan, Tokyo
Gardner Denver Elmo Japan Ltd.

Sweden, Sollentuna
Gardner Denver Nash Scandinavia AB

China, Boshan
Gardner Denver Nash Machinery Ltd.

Korea, Seoul
Gardner Denver Nash Korea Ltd.

USA, Elizabeth, PA
Gardner Denver Nash LLC

England, Winsford, Cheshire
Gardner Denver Nash UK Ltd.

Netherlands, Assendelft
Gardner Denver Nash Benelux B.V.

NASH
A Gardner Denver Product