Integrating Steam Generation from Concentrating Solar Thermal Collectors to Displace Duct Burner Fuel in Combined Cycle Power Plants

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ABSTRACT

Combined Cycle power plants are typically designed with duct firing to augment the steam generated by heat recovered from the gas turbine exhaust. The incremental electrical power output generated as a result of duct firing is typically achieved at a relatively low thermal efficiency. Duct firing is therefore usually economically justified only during mid-day periods of peak electric power demand. Integrating parabolic trough concentrating solar energy collectors with such plants allows displacement of the duct burner fuel by solar thermal input. Such integration can be incorporated into new plant designs, or it can be retrofit in existing plants. Relatively little modification of the existing plant design is necessary for this integration, since the amount of solar energy input can be limited to that which can be accommodated by the capacities of the existing steam turbine, condensate and boiler feed pumps, and heat rejection system. This paper presents typical design and performance features of a representative solar thermal retrofit of a duct fired combined cycle power plant. The paper further discusses the economic value and development advantages of such retrofits relative to stand-alone solar power plants.

1. INTRODUCTION

Parabolic trough Concentrating Solar-thermal Power (CSP) technology represents one of the most promising options for generating renewable electricity at the utility scale. The quandary for CSP, and many other renewable technologies, is that they must be built on a large scale to provide the most compelling economics; but without demonstration and validation at a more modest scale those large projects using innovative technologies are much more difficult to finance.

This paper presents a design study of the retrofit of existing duct-fired combined cycle power plants with parabolic trough CSP technology. These retrofits provide a compelling economic opportunity, even at a modest scale. They further can be developed and constructed more quickly than stand-alone green-field CSP plants. This *FuelSaver™* concept delivers renewable energy while maintaining the dependable capacity inherent in the host power plant, providing a platform to "green" the existing Southwestern combined cycle asset base and accelerating the deployment of innovative parabolic trough CSP technology.

2. BACKGROUND

Prior Research

The notion of integrating steam generated with CSP technology into fossil-fired power plants is by no means a new one. Significant research has been performed covering everything from using solar energy to replace feedwater heaters in coal-fired power plants to building new combined cycle plants designed to accommodate solar generated steam. The largest and most relevant body of work surrounds solar integration with combined cycle power plants [1-7].

While Luz Solar International is typically credited with the original concept [3], the first significant investigation into the integration of CSP technology into combined cycle power plants came with the announcement of a grant offering from the Global Environment Facility (GEF) of the World Bank for these types of plants built in the developing world (India, Egypt, Morocco and Mexico). These grants generated a number of significant feasibility studies [8], and greenfield projects in Egypt and Morocco that are currently under construction [9,10].

Combined cycle power plants are preferred for parabolic trough solar-fossil integration for a number of reasons. First, the steam temperatures and pressures developed in modern triple-pressure heat recovery steam generators (HRSGs) are well-suited to the capabilities of modern trough collectors. Second, using the gas turbine exhaust gas to preheat the feedwater for the solar steam generator allows better recovery of the exhuast gas energy in the low temperature range. Moreover the superheater coils in the HRSG can be used to raise the temperature of the solar-generated steam. As a consequence the solar-to-electric efficiencies that can be realized in an integrated plant are superior to those possible in a stand-alone solar plant [2]. This increase in efficiency results in better economic utilization of the solar collector equipment.

The bulk of the existing research contemplates the design of greenfield combined cycle power plants that include a solar contribution as an alternative to stand-alone solar power plants similar to the SEGS systems[1]. The most common design includes oversizing the plant's steam turbine to accommodate solar steam input, and optionally adding duct firing capability to provide fossil backup to the solar capacity [3,5]. There is also work that explores the more technical details of optimizing HRSG design and steam turbine size to take maximal advantage of the solar input [2].

Other CSP technologies exist that may be suitable for this type of integration, and they have been investigated [6], but parabolic trough is the focus of most analyses (including this one) because in addition to its ability to generate steam at suitable conditions its modularity allows it to be easily scaled to accommodate the land area that is available around existing plants.

The current retrofit opportunity

During the last decade the overwhelming majority of new electric generating capacity in the United States has been in the form of natural gas-based technologies. Over 90% of the approximately 285,000 MW of nameplate capacity that was added to the generating portfolio from 1995-2005 used natural gas as the primary fuel [11]. Further, a significant amount of this capacity was built in the Southwest and came in the form of 2-on-1 combined cycle power plants equipped with supplemental duct-firing capacity in the HRSG to provide low-cost peaking capacity. The steam turbines in these plants are sized to accommodate the additional steam resulting from duct firing. It is common for 2-on-1 combined cycle plants to have 50-150 MW of duct fired capacity.

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[1] The Solar Electric Generating Systems (SEGS) were a series of nine parabolic trough solar power plants with a total capacity of 354 MW built from 1984-1992 in the Mojave Desert.

These duct-fired combined cycle power plants represent a unique opportunity for retrofit with parabolic trough technology. The incremental heat rate of duct firing in combined cycle power plants is very poor compared to their baseload performance, thus the duct burners are typically used only during peak periods. Duct firing further produces substantially higher atmospheric emissions (e.g. NOx, CO, unburned hydrocarbons, and particulates) than the unfired combined cycle plant at baseload, placing additional restrictions on the operation of duct burners. As a result of these limitations, duct firing capacity factors are often very low leaving significant amounts of steam turbine capacity unused for most of the year.

While the retrofit of existing plants does not benefit from the advanced design and optimization that a Greenfield ISCCS system would receive, the oversized steam system is already in place and underutilized representing a sunk cost that makes the economic proposition of a solar retrofit significantly more appealing. A retrofit also provides plant owners with a partial hedge against their exposure to volatile natural gas prices, as well as expanding the options for power marketing due to the "green" attributes of the solar contribution. The high demand for electric power from renewable sources will increase the frequency of dispatch of any combined cycle plant equipped with solar thermal input.

3. DESIGN AND INTEGRATION APPROACH

The most advantageous general design philosophy for retrofit ISCCS power plants is based on remaining within all design limitations of the existing equipment and minimizing the tie-in interfaces. In addition to minimizing the retrofit costs, this philosophy also minimizes the disruption of operation of the existing plant while the solar thermal system is being constructed. The design also allows the existing plant to continue to operate later in conventional duct-fired mode at times when the solar steam generation system is not in service.

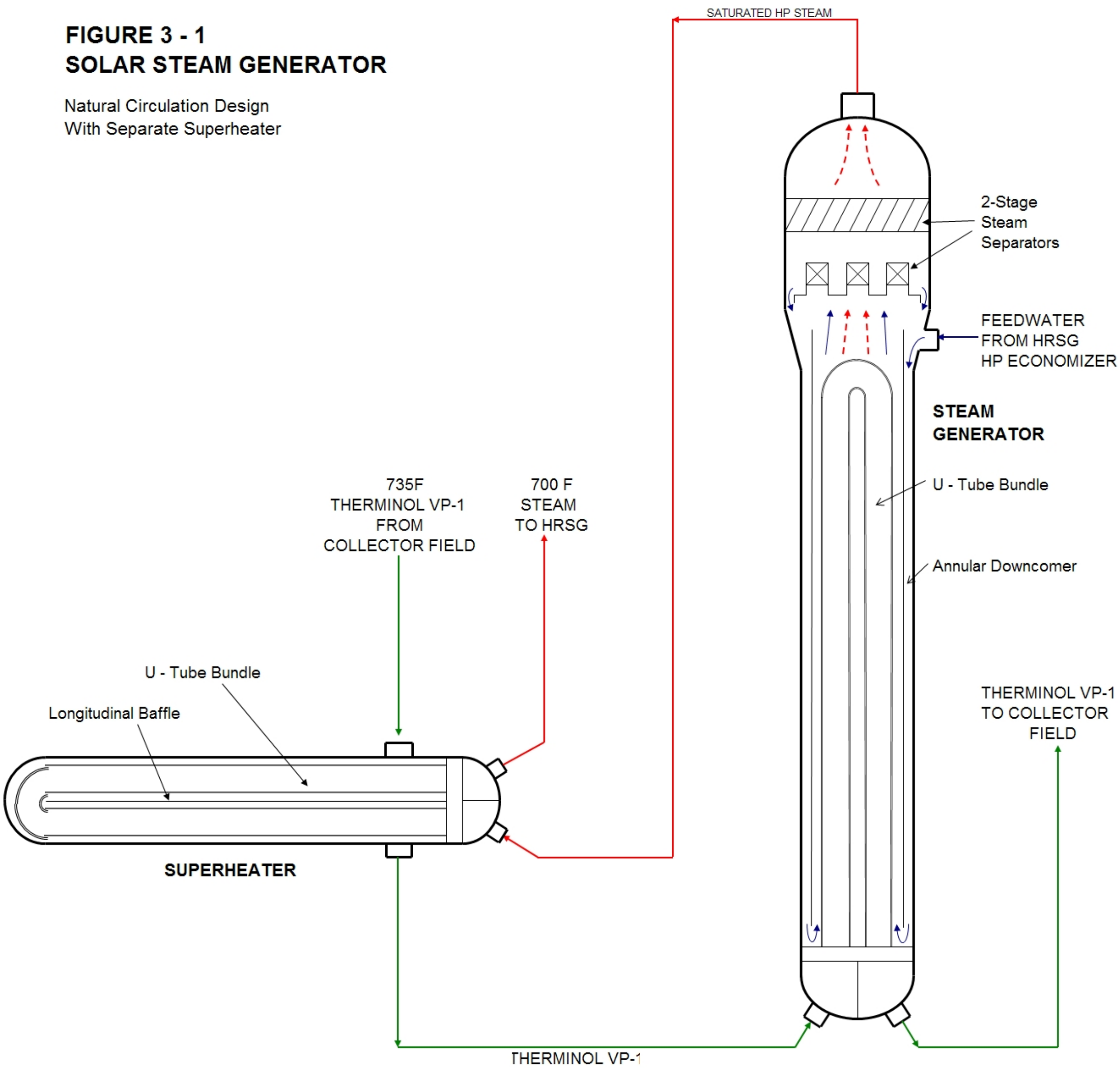
The total steam generated in the integrated plant should be no greater than the existing plant's original design-basis steam generation with maximum duct firing. Therefore no changes are required to the existing HRSG heat transfer surface or safety valve capacity, nor to the steam turbine, condenser, condensate and boiler feed pumps, or circulating water system.

The solar thermal steam generation system consists of a field of concentrating solar collectors; a heat transfer fluid circulation system; a thermal energy storage system, if warranted by the project-specific economics; and one high-pressure solar steam generator for each HRSG of the existing combined cycle power plant. Each solar steam generator can be a shell and tube steam generator section and steam separator with a separate shell and tube superheater section.

The most promising design for the solar steam generator is shown in Figure 3-1. The solar heat transfer fluid is circulated first through the shell side of a steam superheater, then through the tube side of a natural circulation steam generator. For large solar thermal inputs multiple steam generator shells will be required operating in parallel. Preheated feedwater from the outlet of the HRSG HP economizer is piped to the steam separator space of the solar steam generator. The water circulates by natural convection through the shell of the steam generator where it is partially evaporated. Use of a vertical orientation of the steam generator with the Therminol®VP-1 fluid in the U-tube bundle provides for enhanced thermosiphon circulation and allows the steam separator to be integrated with the free-standing steam generator. The water and steam mixture in the shell leaving the top of the tube bundle is separated in the integral two-stage steam-water separator section. The separated steam flows through the tube side of the solar superheater and thence back to the HRSG. The water separated at the top of the steam generator joins the entering feedwater and flows to the bottom of the tube bundle through the annular downcomer passage.

FIGURE 3 - 1
SOLAR STEAM GENERATOR

Natural Circulation Design
With Separate Superheater



Use of a natural circulation steam generator minimizes the pressure drop on the water-steam side. Since circulation through the solar steam generator is driven by the thermosiphon effect, not by pump power, it is possible to divert a portion of the preheated feedwater from the HRSG HP economizer outlet to the solar steam generator without needing to impose a large additional pressure drop in the header between the economizer and the HP steam drum. This allows substantially more energy recovery from the gas turbine exhaust gas in the HRSG compared with other designs in which feedwater is piped to the solar steam generator directly from the discharge of the HP boiler feed pump.

The heat transfer medium that has been proven for commercial use in parabolic trough solar systems for power generation is Therminol® VP-1 (and its equivalents, such as Dowtherm A). The maximum service temperature for these fluids is 750°F, thus limiting the economically achievable superheat temperature to about 700°F. At these temperatures, the generated solar steam is returned to the same HRSG that provided the feedwater just downstream of the HP drum. In the future, molten salt may be used as the heat transfer fluid in parabolic trough solar fields, enabling superheated solar steam temperatures in the range of 800-950°F. This analysis focuses on systems utilizing the commercially-proven Therminol®VP-1 fluid.

No IP or LP steam is generated by the solar steam system, since the capital cost of the solar collectors is most economically applied to HP steam generation. Moreover, the existing condensate pump and IP boiler feedpump capacities are typically not suitable for the significant incremental flow rates that would be required for solar steam generation at those pressures, compared to their duct fired design bases.

At times of off-peak solar thermal input, it is possible to supplement the solar steam generation by using the existing duct burners, again, up to the design limits of the existing components.

With the duct burners off, and at high solar steam inputs at 700°F, the superheater and reheater sections in the existing HRSG are in general not able to reach their full design-basis outlet temperatures. This should cause no problem for steam turbine operation, since the cycle conditions selected for each plant should keep steam turbine exhaust moisture content well within acceptable limits. Transitions to and from operation with solar steam input should be controlled for gradual component temperature rates of change so that no significant thermal stresses are introduced.

The above superheater outlet temperature considerations are most pronounced when the solar steam input is equal to the entire incremental steam flow that is produced with full duct firing, compared to unfired operation. In many cases, the solar system will not be designed to achieve the fully-fired incremental steam flow. In these cases, superheater outlet temperature considerations will be less of an issue, as the solar contribution will represent a smaller percentage of total steam flow. Moreover, partial duct firing to supplement solar input will be possible without exceeding feedwater pump capacity or steam turbine throttle pressure limits, mitigating any reduction in superheater outlet temperature due to solar input.

A simpler solar steam generator system is possible if the superheater section is eliminated. However, this will reduce the thermal efficiency of the integrated power cycle and exaggerate the lowering of the throttle temperature that was just discussed. The economics of such an arrangement are best evaluated based on project-specific conditions, and are expected to be favored for relatively small solar thermal inputs.

The major tie-ins between the solar thermal steam generation system and the existing combined cycle power plant are simply (a) a single feedwater supply connection from each existing HRSG's HP economizer outlet header to the solar steam generator, (b) a single superheated steam connection from each solar steam generator to an appropriate header in each HRSG's HP steam circuit, and (c) controls interface via redundant digital communication links between the existing plant DCS and the solar thermal system's independent microprocessor-based control system.

Control of the flow rate of feedwater to the solar steam generators is based on maintaining a constant solar steam outlet temperature. Circulation of the solar heat transfer medium is controlled to maintain nominally constant heat transfer medium supply and return temperatures. This control philosophy eliminates any significant thermal cycling in the solar steam generators and in the existing plant's steam systems.

Complete isolation of the solar steam generation system from the existing plant is possible by simply closing the isolation valves in the feedwater and steam tie-in lines.

4. MODELING METHODOLOGY

The performance of the ISCCS plant was estimated by means of a Thermoflex™ heat balance model for an operating combined cycle power plant in the Southwest U.S. This model was first created for the original duct-fired combined cycle plant and faithfully replicates the performance characteristics of the existing equipment and systems at various ambient conditions and load levels. Then varying amounts of solar thermal input were added and the performance compared to the base cases with no solar input.

Similar models can be created for any other existing combined cycle plant that is a candidate for retrofitting with solar thermal input.

A typical heat balance diagram for the ISCCS power plant is shown in Figures 4-1A and B. This diagram applies to the case of full gas turbine load and a solar thermal input of nominally 104 MWth per HRSG (208 MWt total) at ambient conditions of 90°F and 20% RH. For comparison purposes Figures 4-2A and B show the original reference plant design at the same ambient conditions with no duct firing or solar thermal input. Each of these two-sheet heat balance diagrams have been excerpted from a set of five Thermoflex model sheets. The first sheet shows a single gas turbine and HRSG train, which is identical to the second such train in the plant. Sheets showing the joining and splitting of streams between the two HRSGs and the steam turbine system have been omitted for the sake of simplicity. Therefore, in most cases the identification numbers in the connector arrows between sheets in these figures should be disregarded.

The HRSGs have three pressure levels (HP, IP, LP), with reheat design. A duct burner is installed downstream of the second reheat and second superheater sections. The HRSG hardware information in the model was taken from the reference plant's HRSG data sheets. The performance parameters of the two HRSGs (steam flow rates from each section, superheater outlet temperatures, pressure drops on the gas and water-steam sides, etc.) were then tuned to match the manufacturer's guaranteed data.

The reference combined cycle plant has two GE 7241FA gas turbines, equipped with evaporative inlet air coolers. Fuel gas is preheated by fuel gas heaters before entering the gas turbines using IP feedwater from the outlet of the IP economizers. Fuel gas is heated to 365°F.

Each unit's steam turbine is a two casing, tandem compound, double flow exhaust, condensing unit consisting of a high-pressure turbine, an intermediate-pressure turbine, and a double-flow low-pressure turbine. The high-pressure and intermediate-pressure turbines share a common casing, and the double-flow low-pressure turbine is in a separate casing.

The following steam turbine constraints were observed for all heat balance runs:

1. The steam turbine rated inlet and reheat pressures and temperatures were not exceeded for any of the heat balance cases with solar thermal input.
2. The condenser pressure for all of the heat balance cases with solar input is always lower than the backpressure alarm limit of 10" Hg for the existing steam turbine.

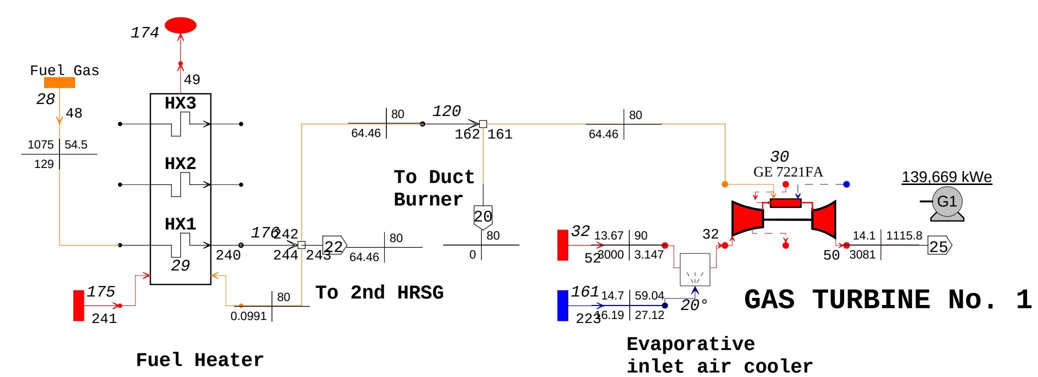
The existing combined cycle unit has an air-cooled condenser.

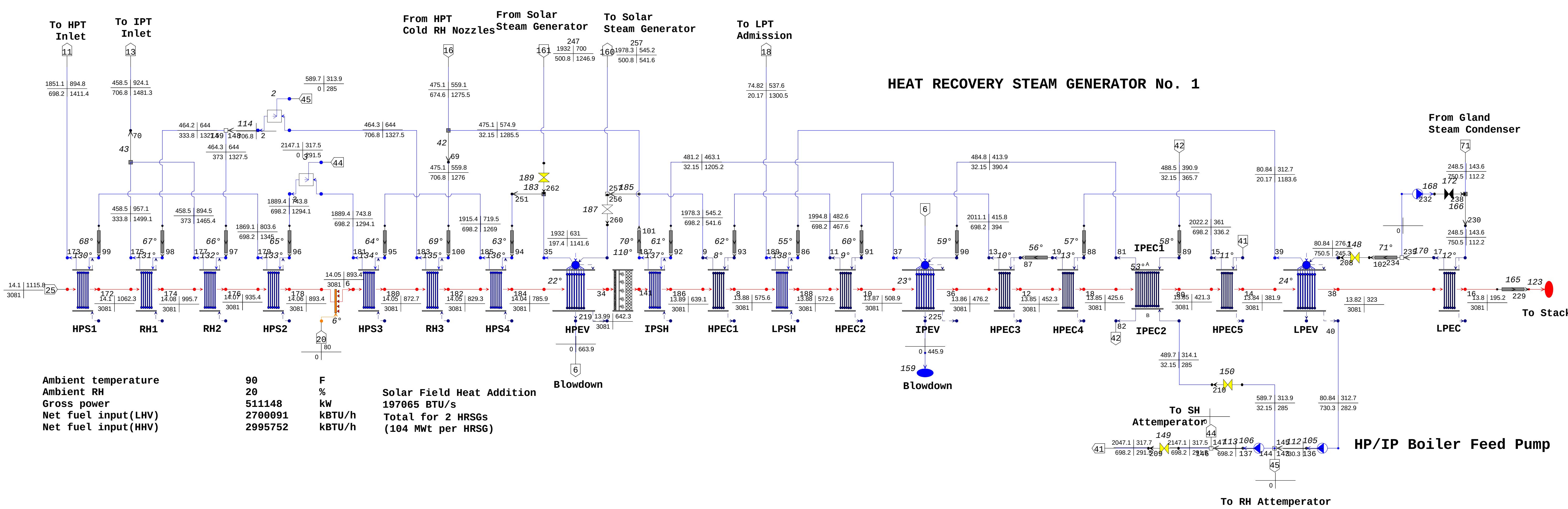
The feedwater pumps are multi-stage, with an interstage bleed to supply the IP boiler circuit. Each pump was modeled as two discrete pumps in series. Two 100% capacity pumps are provided. During duct firing, or during times of high solar thermal input, both pumps run in parallel. The existing feedwater pump capacity was derived from the manufacturer's feedwater pump curve. For all heat balances cases, the feedwater flow and head requirement was kept within the design capacity of the existing feed pumps.

Table 4-1 presents the major power cycle performance parameters for the ISCCS with and without solar thermal input, and without duct firing. The total solar thermal input to both HRSGs varies from zero to 208 MWt, with intermediate cases at 75%, 50% and 35% of peak solar input. For the sake of comparison Table 4-2 presents the same data for the cases without solar input but with the design rate of duct firing. All cases are based on full load gas turbine operation at the ambient conditions in question.

FIG. 4-1A ISCCS POWER CYCLE WITH SOLAR THERMAL INPUT (GAS TURBINE AND HRSG SUBSYSTEM)

ONE GAS TURBINE AND HRSG TRIAN SHOWN.
TYPICAL OF TWO TRAINS FEEDING A COMMON
STEAM TURBINE GENERATOR.





Ambient temperature	90	F
Ambient RH	20	%
Gross power	511148	kW
Net fuel input(LHV)	2700091	kBTU/h
Net fuel input(HHV)	2995752	kBTU/h

Solar Field Heat Addition
197065 BTU/s
Total for 2 HRSGs
(104 MWt per HRSG)

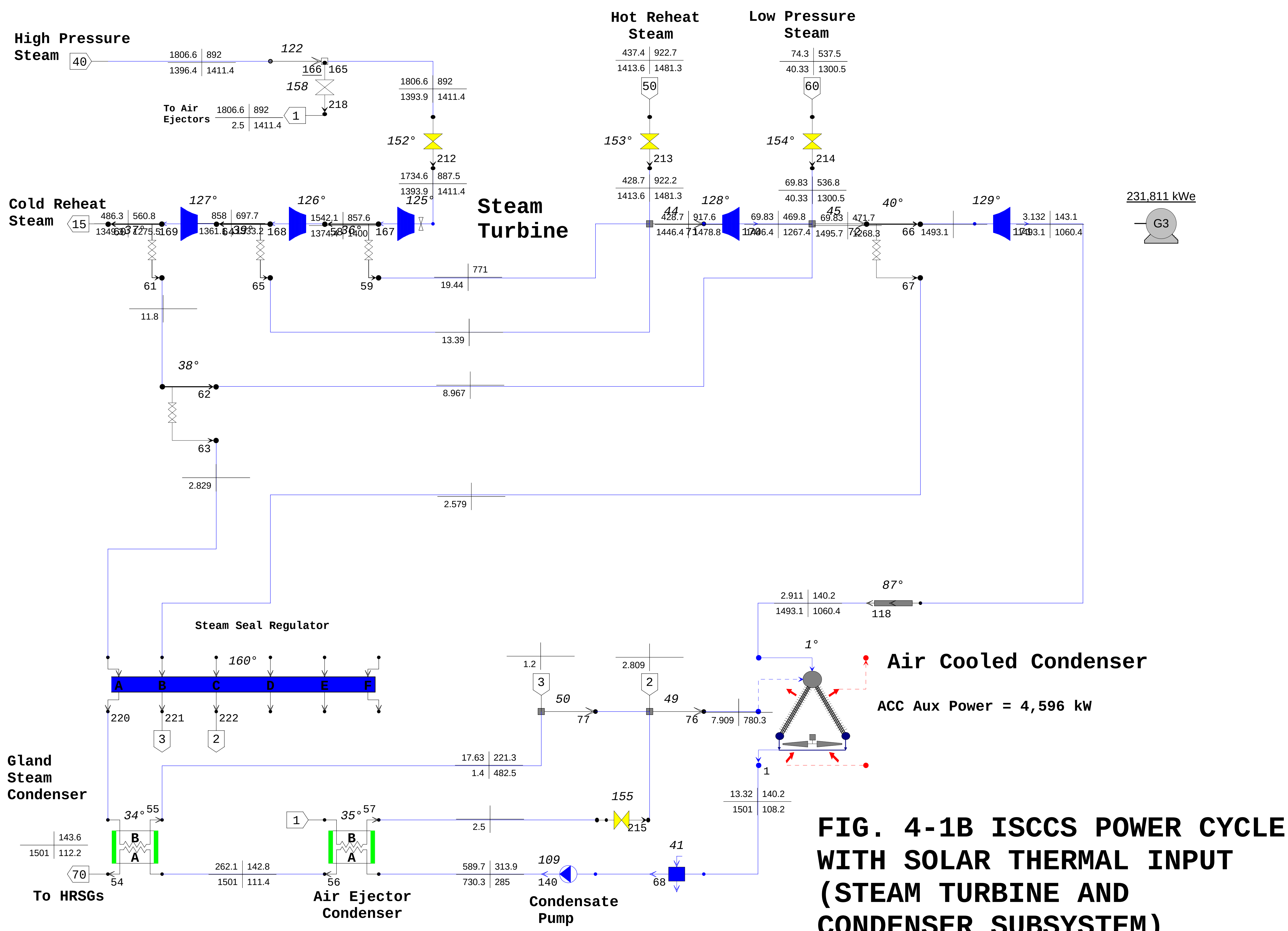
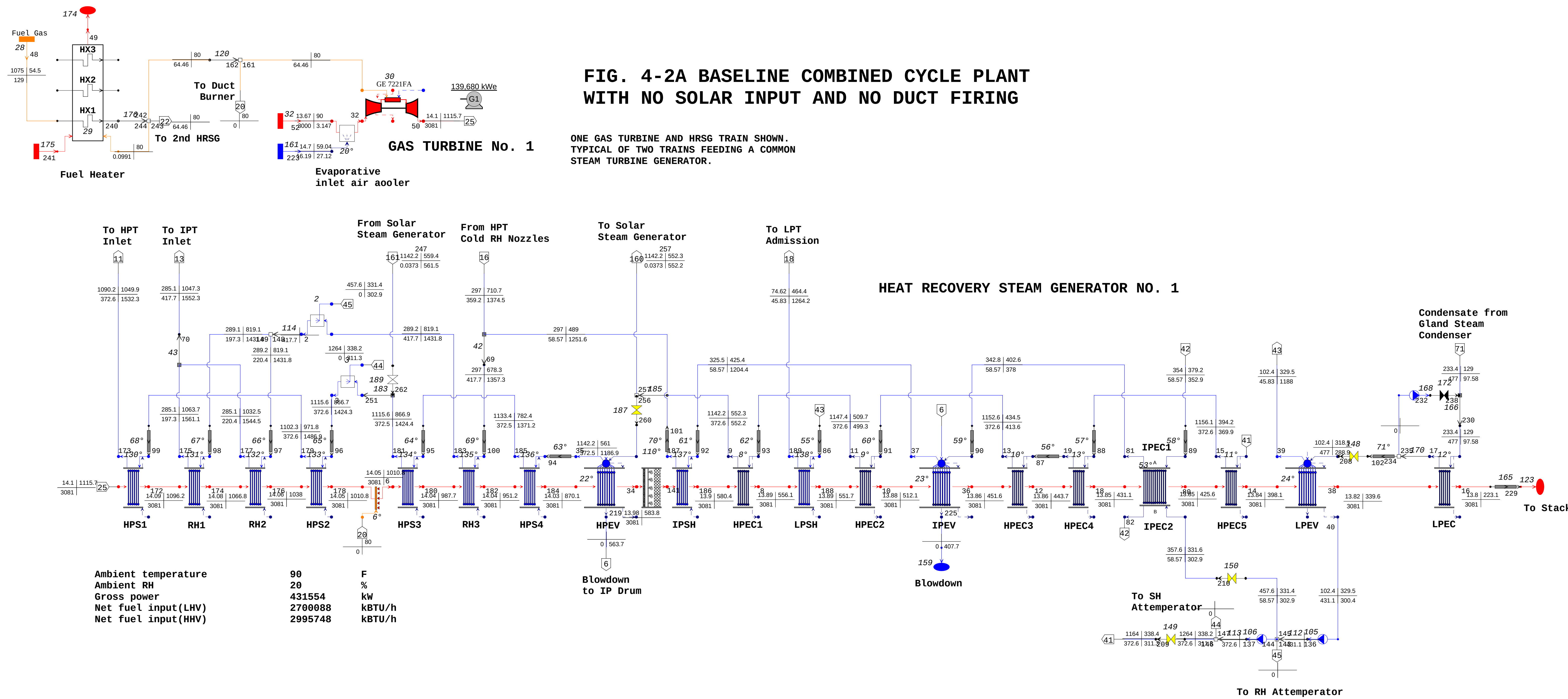


FIG. 4-1B ISCCS POWER CYCLE WITH SOLAR THERMAL INPUT (STEAM TURBINE AND CONDENSER SUBSYSTEM)

FIG. 4-2A BASELINE COMBINED CYCLE PLANT WITH NO SOLAR INPUT AND NO DUCT FIRING

ONE GAS TURBINE AND HRSG TRAIN SHOWN. TYPICAL OF TWO TRAINS FEEDING A COMMON STEAM TURBINE GENERATOR.



Ambient temperature	90	F
Ambient RH	20	%
Gross power	431554	kW
Net fuel input(LHV)	2700088	kBTU/h
Net fuel input(HHV)	2995748	kBTU/h

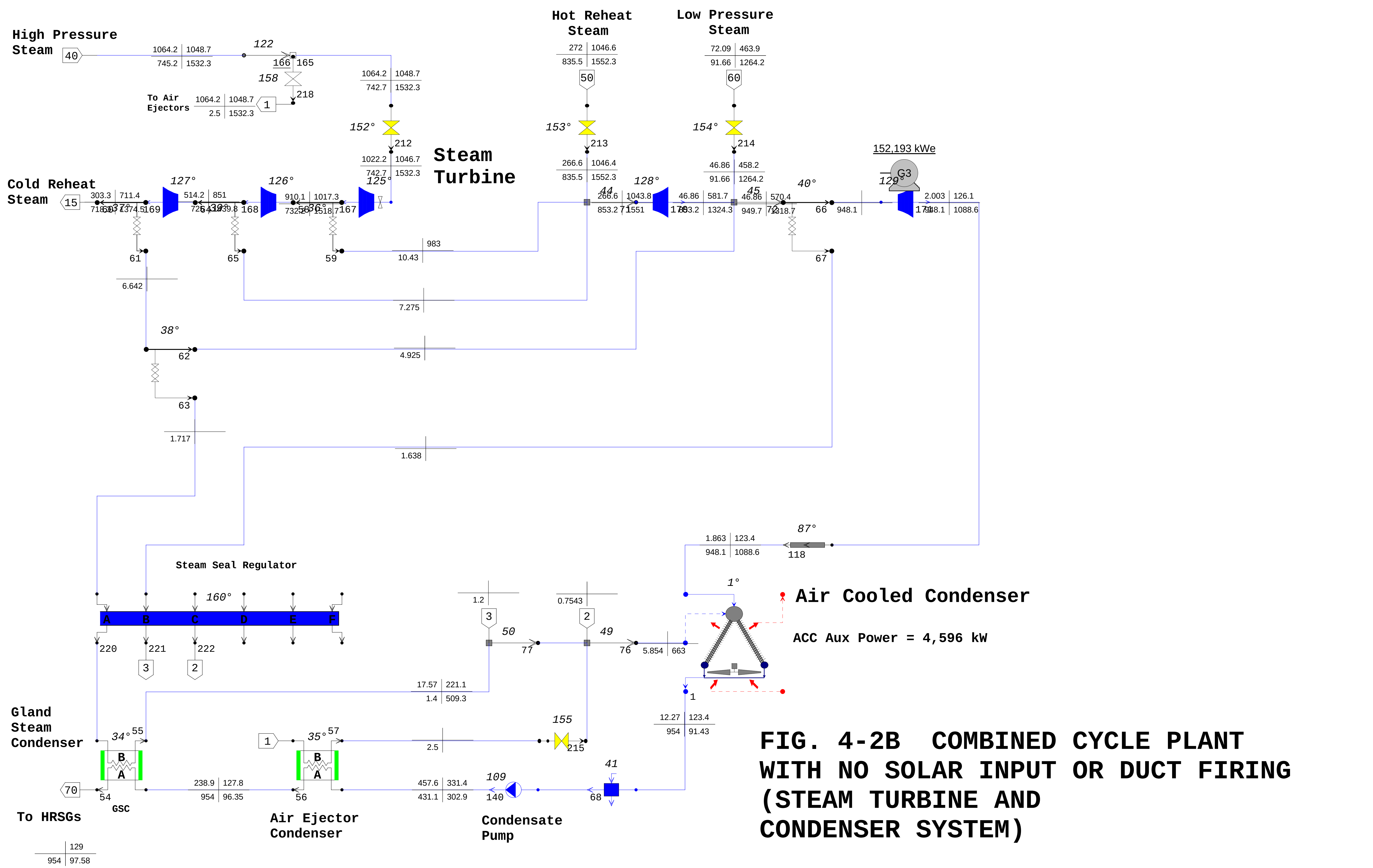


FIG. 4-2B COMBINED CYCLE PLANT WITH NO SOLAR INPUT OR DUCT FIRING (STEAM TURBINE AND CONDENSER SYSTEM)

TABLE 4-1 ISCCS PERFORMANCE - NO DUCT FIRING

Ambient Temperature, °F	**105**					**90**				
Relative Humidity, %	**15**					**20**				
Evaporative Cooler Status	**On**					**On**				
Total Gas Turbine Gross Output, MWe	270.6					279.4				
Solar Thermal Input, MWt	208	156	104	52	0	208	156	104	52	0
Solar-Generated Steam Flow, lb/hr	997,290	735,130	481,220	235,700	0	1,000,140	737,040	482,490	236,330	0
Total Steam Flow to STG, lb/hr	1,385,210	1,208,600	1,042,270	884,670	736,880	1,391,540	1,214,136	1,047,816	890,208	741,550
STG Throttle Pressure, psia	1731	1557	1379	1199	1018	1734	1560	1383	1203	1022
STG Throttle Temperature, °F	892	936	979	1019	1046	888	932	974	1013	1047
Condenser Pressure, "HgA	8.8	7.9	7.1	6.4	5.8	5.9	5.3	4.7	4.2	3.8
Steam Turbine Gross Output, Mwe	221.0	204.0	185.4	165.5	144.5	231.9	213.9	194.6	173.9	152.2
Power Island* Aux Load, MWe	18.5	17.6	16.9	16.4	15.9	18.6	17.7	17.0	16.4	16.0
Net Plant Output, Mwe	473.1	457.0	439.1	419.7	399.2	492.7	475.6	457.0	436.9	415.6
Ambient Temperature, °F	**70**					**50**				
Relative Humidity, %	**35**					**50**				
Evaporative Cooler Status	**On**					**Off**				
Total Gas Turbine Gross Output, MWe	290.7					304.7				
Solar Thermal Input, MWt	208	156	104	52	0	208	156	104	52	0
Solar-Generated Steam Flow, lb/hr	1,003,000	739,090	483,750	236,970	0	1,006,000	741,310	485,340	237,600	0
Total Steam Flow to STG, lb/hr	1,397,880	1,220,470	1,053,360	895,750	746,940	1,404,220	1,226,020	1,058,900	901,300	751,370
STG Throttle Pressure, psia	1739	1565	1387	1207	1027	1740	1566	1389	1209	1029
STG Throttle Temperature, °F	883	926	967	1005	1039	877	919	959	997	1029
Condenser Pressure, "HgA	3.4	3.0	2.7	2.4	2.1	2.1	2.0	2.1	2.1	2.0
Steam Turbine Gross Output, Mwe	239.0	220.6	200.6	179.5	157.6	241.1	222.3	201.8	180.4	158.2
Power Island* Aux Load, MWe	18.7	17.8	17.2	16.6	16.1	18.6	17.5	16.5	15.7	15.0
Net Plant Output, Mwe	511.0	493.5	474.1	453.6	432.2	527.2	509.5	490.0	469.4	447.9

* Not including solar field aux load

TABLE 4-2 CC PERFORMANCE - WITH DUCT FIRING

(No solar thermal input)

Ambient Temperature, °F	**105**	**90**	**70**	**50**
Relative Humidity, %	**15**	**20**	**35**	**50**
Evaporative Cooler Status	**On**	**On**	**On**	**Off**
Total Gas Turbine Gross Output, MWe	270.6	279.4	290.7	304.7
Duct Burner Thermal Input, MWt	251.3	258.4	261.3	265.1
Total Steam Flow to STG, lb/hr	1,372,540	1,397,880	1,413,720	1,431,140
STG Throttle Pressure, psia	1847	1875	1888	1902
STG Throttle Temperature, °F	1047	1041	1032	1022
Condenser Pressure, "HgA	9.2	6.3	3.6	2.2
Steam Turbine Gross Output, Mwe	246.8	260.9	269.6	273.3
Power Island* Aux Load, MWe	17.2	17.3	17.5	17.5
Net Plant Output, Mwe	500.0	522.6	542.4	560.1

5. PLANT OPERATIONAL & PERFORMANCE CHARACTARISTICS

Figure 5-1 shows the conversion efficiency from thermal to electric energy for the incremental solar steam added to the studied plant at baseload for a variety of ambient conditions. The conversion efficiency is calculated as follows:

$$\eta = \frac{incremental\ net\ plant\ output\ [MWe]}{solar\ thermal\ input\ [MWth]}$$

Note that the definition of FuelSaver™ efficiency presented here accounts for incremental power block parasitic loads by using the net plant output, but does not consider parasitic electrical loads in the solar field. It is easier to model the system when solar field parasitics are calculated and added separately.

In the figure 100% solar field design output is equal to the maximum thermal input that the existing combined cycle plant can accommodate without modification, assuming the solar field is custom designed for the combined cycle plant in question. In the analysis of the plant studied for this paper, the capacity of the HP boiler feed pump was the factor that first limited the addition of more solar steam.

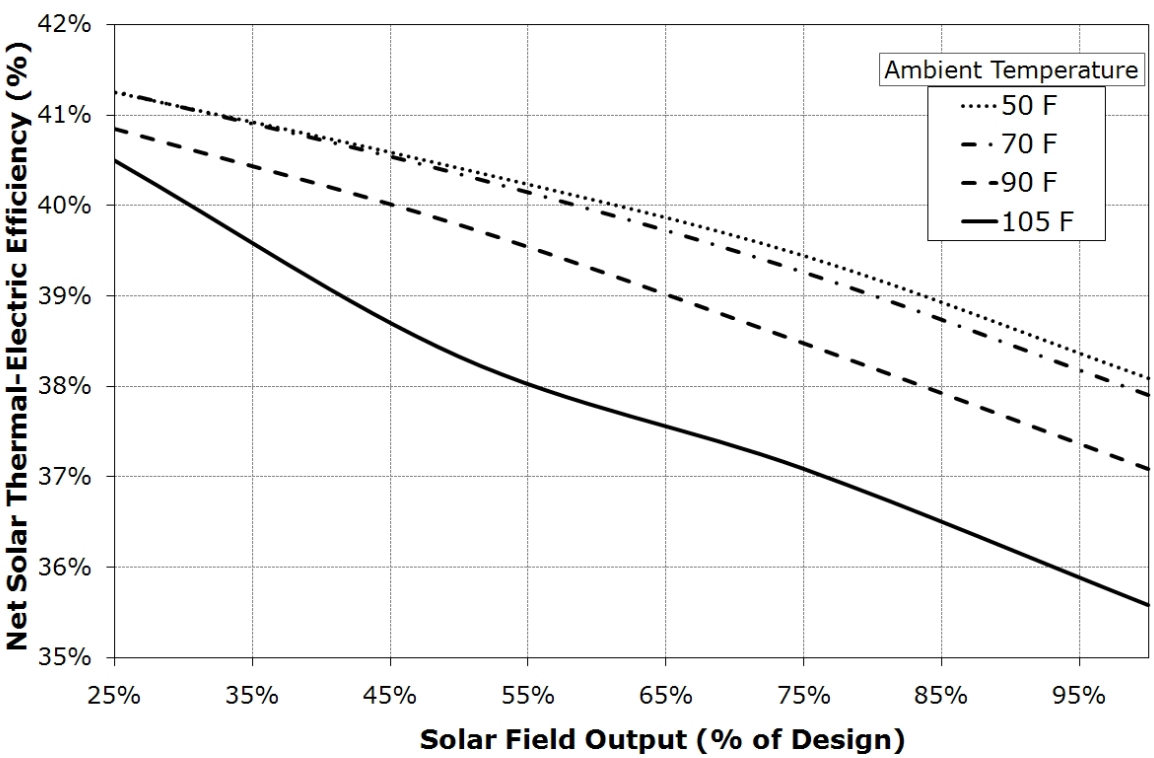


Figure 5-1. FuelSaver solar thermal-electric conversion efficiency assuming gas turbines operating at base load at various ambient conditions. Efficiency is net of power island parasitics, but not solar field parasitics.

Figure 5-2 shows the part-load performance curve of a FuelSaver™ system as compared to a stand-alone parabolic trough solar power plant (like the SEGS plants in the Mojave Desert, CA). The SEGS-type plants show a reduction in performance when operating at part-load, where the FuelSaver™ system shows the opposite result. The reason for this behavior in the FuelSaver™ case is two-fold. First, as more solar steam is added at a modest 700°F, the exhaust gases from the combustion turbines are no longer able to superheat the (now larger) steam flow to the design inlet temperature for the steam turbine (typically 1000°F+), reducing steam turbine efficiency. Second, the incremental solar steam, by increasing the duty in the superheater section, is displacing additional high-pressure (HP) steam generation in the HRSG. The largest temperature differences between exhaust gas and steam exist in the HP evaporator section of the HRSG; thus from a second-law perspective these are the least efficient portions of the steam generation process in the HRSG. The addition of solar steam offsets this relatively inefficient process, increasing the second law efficiency of the steam generation process in the HRSG. However, as the solar contribution increases the temperature differences that are offset are also reduced, and so with them are the gains in efficiency [2].

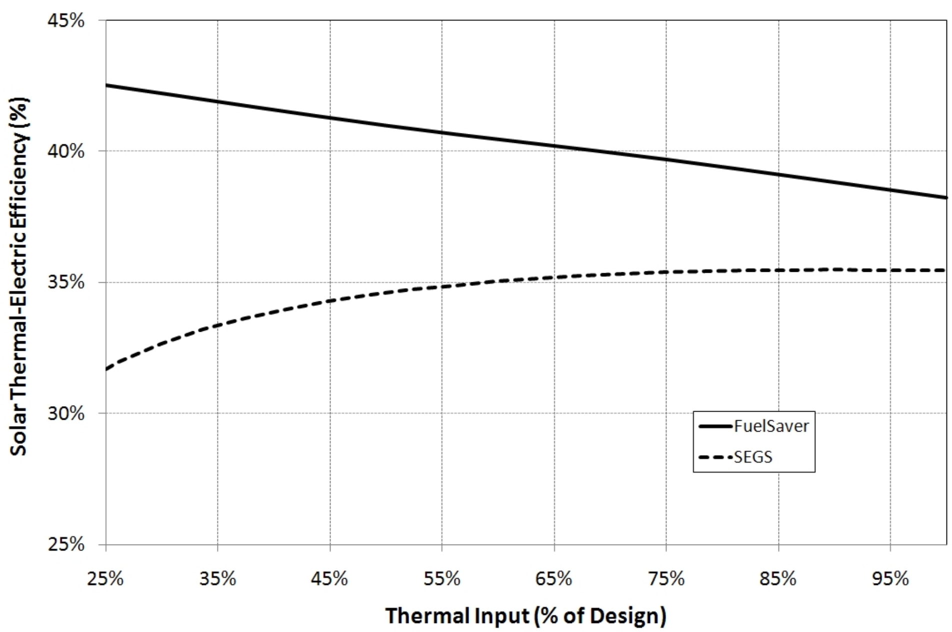


Figure 5-2. Net solar thermal-electric steam cycle (not including solar field pumping loads) efficiency comparison between a SEGS-type stand-alone solar power plant and a FuelSaver™ at 90°F ambient, for which 100% design thermal FuelSaver™ input is defined as the maximum allowable input without modification made to the HRSGs.

The foregoing discussion does not account for further gains in incremental solar thermal-electric efficiency that will be possible at reduced solar thermal inputs as a result of partial duct firing in the HRSG. If warranted by the electric power demand, the plant owner may opt to use the duct burners to supplement the solar field at times of reduced insolation. The duct firing would then be adjusted to maximize the steam and feedwater flow rates, within the design constraints discussed previously. The incremental net solar electric power output in such modes of operation would be compared to the combined cycle output at that duct firing rate but without solar thermal input. Since the effect of the partial duct firing will be to raise the superheat temperature, the incremental electrical output per unit of solar thermal input will be greater than for the unfired case.

6. ECONOMIC PERFORMANCE

FuelSaver™ offers a compelling economic proposition relative to the development of stand-alone parabolic trough projects for two principle reasons, (i) the "brown field" project development process has fewer pitfalls and (ii) the capital cost is significantly reduced as the system is utilizing already-existing electricity generating infrastructure. The project financial risk is correspondingly reduced, compared to a stand-alone solar power plant.

Project Development Advantages

Summarized below are a range of benefits that make developing a project based on the FuelSaver™ approach faster and more compelling than traditional stand-alone solar power project development:

- "Brown-field" development typically implies less permitting risk.
- FuelSaver™ greens existing capacity rather than adding new capacity to the host plant, so the required transmission capacity and infrastructure is already in place to deliver the energy to the market.
- Steam turbine and generator equipment are already in place – these are some of the most expensive and longest lead-time items in a stand-alone project.
- Additional power marketing opportunities exist for plants that produce both green and brown power.
- Without the economies of scale of steam cycle equipment that dominate stand-alone project economics, smaller FuelSaver™ projects (~5MWe+ incremental power output) can be economically competitive.
- Overall faster development than stand-alone projects due to fewer long lead-time items and permitting hurdles.
- Reduced project financial risk

While these advantages are significant, there are also unique challenges that can impact these projects:

- Plant dispatch may be insufficient to utilize all the steam developed by the solar system.
- Economics of duct burner dispatch must be compared to the economics of solar integration.
- If the solar collection field and solar steam generation system is owned by an entity other than the combined cycle plant owner, elaborate plant ownership structures can complicate the development and design process.
- There is some lingering perception of technical risk associated with this integration approach, but this is quickly disappearing as the industry begins to look more closely at what is involved [12].

Project Economics

A comparison between a stand-alone solar power plant and FuelSaver™ application both utilizing identical parabolic trough solar fields is presented here to demonstrate the economic advantages of FuelSaver™ development. While a real-world economic case would undoubtedly be more complicated, this analysis is designed to capture the fundamental economic drivers. The results of this analysis are summarized in Table 6-1.

The stand-alone case is a typical 100 MWe design featuring a solar multiple of 1.4. The solar multiple implies that at peak solar conditions (1000 W/m^2 with the sun high in the sky) the solar field is capable of producing 40% more thermal energy than the power block can effectively utilize. Stand-alone plants are oversized in this way in order to optimize their overall economics. If the field were not oversized, the power block would only achieve its rated output during peak summer conditions. While oversizing the solar field does cause some energy to be "wasted" during peak solar periods, as a result the power block is able to run more often throughout the year, allowing it to operate at higher efficiency and better utilizing the investment made in the power block equipment.

Unlike the stand-alone case, the FuelSaver™ case has a solar multiple of 1.0. There is no need to oversize the solar field in the case of FuelSaver because (i) there is no part-load penalty when the solar system does not achieve its design output and (ii) the power block investment has already been made so there is no economic incentive to increase its utilization. As a result, the capacity of the FuelSaver™ system is significantly higher (140 MWe), even though the solar field size is identical to the stand-alone case. While 140 MWe is larger than most expected FuelSaver™ installations, there are numerous plants in the American Southwest that can accommodate systems of this size.

The cost estimates for both systems were compiled from data from SkyFuel, Inc. and a variety of industry estimates, including those supplied with the NREL SAM model [13]. In both cases there is no provision for storage of solar thermal energy. While getting precise cost data is a nearly impossible task, it is the relative magnitudes of the various cost categories (solar field, power block, FuelSaver™ integration) that drive the relative economic performance – and those differences show general continuity between the various available estimates.

An estimate of annual performance was made for both systems. The performance of the stand-alone system was computed with the *Solar Advisor Model* (SAM), a program produced by the National Renewable Energy Laboratory [13]. The performance of the FuelSaver™ case was performed using the estimates of solar field thermal output generated by SAM and the efficiency of the FuelSaver™ installation presented earlier in this paper. For the purposes of this simplified example, it was assumed that the host combined cycle plant was baseloaded and available to accept solar-generated steam whenever it was available. This is a reasonable assumption, in view of the high demand for power from renewable sources. For this case the host plant was assumed to be designed with two GE Frame 7FA gas turbines, and a design-duct firing rate sufficient to accommodate 410 MWth input from the solar field. The result of this analysis shows that the FuelSaver™ system will produce close to 30% more energy to the grid on an annual basis than the stand-alone system. This is primarily a result of (i) the favorable part-load performance of

FuelSaver™ and (ii) the lack of oversizing resulting in no "wasted" solar field output during the summer.

Assuming an unlevered after-tax project IRR of 10% and the 30% investment tax credit, the FuelSaver™ system requires a first-year energy price of $96.50/MWh-e as compared to $148/MWh-e for the stand-alone system. This implies that FuelSaver™, in the right circumstances, can produce renewable energy from a parabolic trough solar field at a rate 35% below that which is required by a comparable stand-alone system.

There are other economic incentives that would motivate retrofit of solar thermal input to an existing combined cycle plant, thus lowering the effective energy price. One important such incentive would be the increase in plant dispatch frequency due to the high demand for the renewable component of the plant's output. The consequent increase of an existing plant's capacity factor, i.e. the greater utilization of fixed assets, can be of significant financial benefit to the owner. The impact of the greater dispatch frequency can be even more pronounced if the ISCCS design includes provision for solar thermal energy storage.

Table 6-1. Summary economic comparison between FuelSaver(TM) and Stand-Alone plants

	Case 1 - Stand Alone	Case 2 - FuelSaver™
Solar Field Size, m^2	608,304	608,304
Solar Field Thermal Capacity, MW-th	410	410
Solar Multiple	1.4	1
Solar Resource	Mojave Desert, CA	Mojave Desert, CA
Design Electric Output, MW-e	100	140
Annual Capacity Factor, %	26.40%	24.10%
Annual Output, MWh-e	231,000	296,000
Solar Field Cost*, $	$261,500,000	$261,500,000
Power Island** / Integration Cost***, $	$119,000,000	$35,000,000
Total Direct Cost, $	$380,500,000	$296,500,000
Total Direct Cost, $/kW-e	$3,805	$2,118
O&M Cost, $/MWh-e	$32	$28
Unlevered Project Return, %	10%	10%
Escalation (For Energy and O&M), %	2.50%	2.50%
Energy Price, $/MWh-e	**$148.00**	**$96.50**

*Solar Field Cost includes: preparation of solar field site, collector installation, field wiring and solar field controls, heat transfer fluid pumps, piping and controls.
**Power Island Cost includes everything from solar steam generators to the generator busbar.
***Integration Cost includes: solar steam generators, interconnection piping & valves, and controls integration.

7. CONCLUSIONS

The combined cycle power plant building boom in the United States has produced a unique opportunity for retrofitting many of those plants with solar-thermal systems. The amount of solar thermal input that can be integrated into such plants will depend on the amount of duct firing they were originally design for. These FuelSaver™ integrations provide thermodynamic and economic performance that is superior to a comparable stand-alone project built using the same parabolic trough solar technology. Further, the ability of FuelSaver™ projects to provide compelling economics at relatively modest sizes makes them an ideal platform to help advance solar-thermal technology as it begins to be more accepted by the power plant and project finance industries in the United States.

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