SITING POWER PLANTS IN THE PACIFIC N.W.

Submitted to:

WORLD GENERATION

Submitted by:

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INTRODUCTION

This article compares the siting of high-efficiency distributed cogeneration facilities close to energy load centers with the practice of locating large combined-cycle power plants at distant locations. The comparison considers the following factors not commonly considered during plant siting.

- Total efficiency - delivered energy
- Delivered energy cost, including the embedded infrastructure costs
- Marginal air emissions per net delivered kilowatt-hour (kWh)
- Marginal water consumption per net delivered kWh
- Energy supply system reliability

BACKGROUND

The siting of large electric power generating facilities is commonly focused on locations that are distant from energy load centers. The choice of distant locations can be explained by the NIMBY "not in my backyard" mentality. It is also true that new facilities are usually located at the intersection of high-voltage electric power transmission lines and natural gas pipelines. The obvious reason is the need for natural gas to fuel the facility and for electric transmission lines to deliver energy to distant load centers. Unfortunately, developers do not always understand the load-carrying capacity of electric transmission systems and the cost and schedule requirements to expand them. In most cases, the siting of a new energy facility does not consider the overall efficiency of delivered energy, total embedded costs including infrastructure expansions, marginal air emissions, and marginal water consumption. Even more important, high-efficiency industrial cogeneration located at industrial load centers produces significant fuel efficiency and energy costs savings compared with large central power stations.

In the Pacific Northwest, the Bonneville Power Administration (BPA) recently issued a report, "Upgrading the Capacity and Reliability of the BPA Transmission System," that documents the cost of transmission system improvements that will be necessary to meet electricity demands. A number of these improvements are needed because generation facilities are being planned at locations east of the

Cascade Mountains that are remote from load centers to the west. The costs for transmission improvements and the associated high-voltage substation facilities range from about $1 million per mile to more than $4 million per mile. The total investment needed for the BPA transmission system improvements is estimated to be more than $750 million. Similar constrained transmission systems exist in California and other western states.

Siting high-efficiency distributed cogeneration facilities at major load centers, produces significant energy efficiencies and fuel cost savings and also could reduce the cost of some major transmission improvements. Modern cogeneration facilities are usually difficult for the public to identify within the boundaries of a large industrial plant and have environmental impacts that, in many cases, are positive (e.g., reducing local air emissions). This can help diminish the public's NIMBY reaction.

APPROACH

To make the comparison, two different cases are evaluated, as described below.

Combined-Cycle Power Plant

This case, illustrated in Figure 1, is a nominal 470-megawatt (MW), combined-cycle power plant located in Redmond, Oregon, remote from energy load centers. Several large electric transmission lines and a natural gas pipeline run north to south in the vicinity of Madras, Redmond, Bend, and Klamath Falls, Oregon. Recent plant sitings in Oregon have focused on sites east of the Cascades along this north-south corridor and also in northeastern Oregon in the Hermiston area. The transmission system from these areas to the load centers west of the Cascades is constrained and will require expansion to deliver electricity to Western Oregon load centers.

The combined-cycle power plant performance will be based on use of the General Electric 7FA gas turbine technology. (Other manufacturers, such as Siemens-Westinghouse and Alstom, market similar gas turbine technology; the actual manufacturer of the gas turbine is immaterial for this comparison.) It is assumed that the combined-cycle power plant provides no cogenerated energy. One of the generally accepted principles in the power industry today is that cogeneration systems are more energy efficient but less economical because of the higher market value of electricity compared with steam. The validity of this concept is evaluated.

The high-voltage transmission system will probably have to be expanded to deliver the generated electricity from the Central Oregon site to the load centers west of the Cascades. The exact nature and cost of the required interconnections are impossible to define without a detailed system integration study. It is assumed that the combined-cycle power plant will deliver power to the electric transmission system at 230 kilovolts (kV) and that new transmission lines will have to be built to deliver the power to the load centers in Western Oregon. It is also assumed that 100 miles of new transmission line and associated substations will be built. The cost for such transmission/substation improvements could be between $100 million and $150 million. This cost is in the range of current BPA forecasts for new transmission facilities in the Northwest.

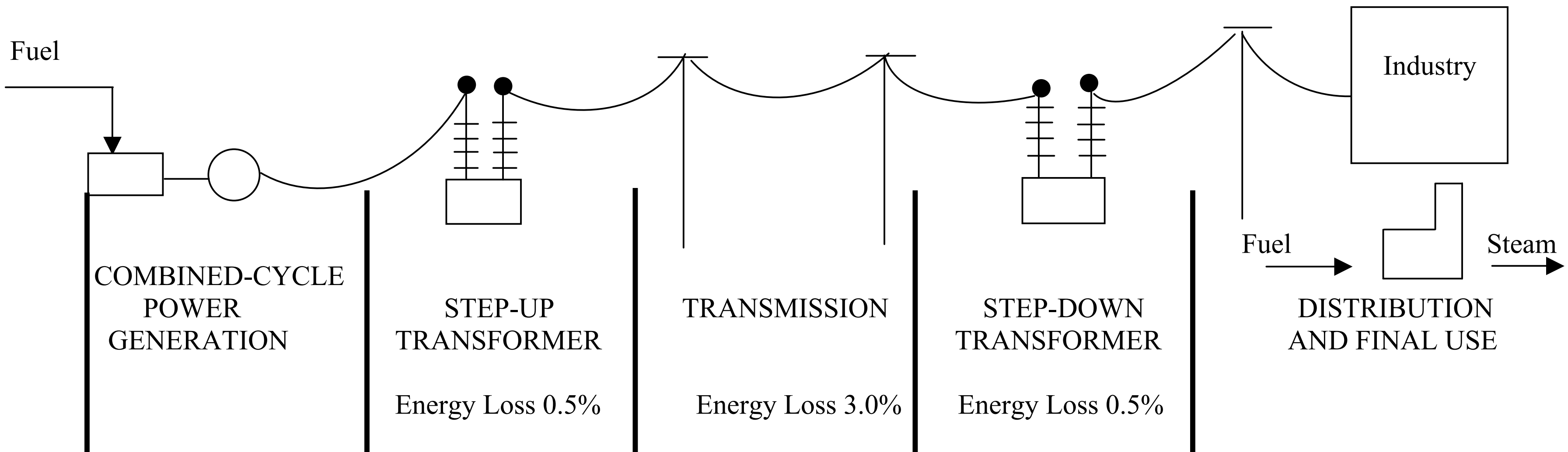

FIGURE 1
REMOTE ELECTRICITY PRODUCTION AND SEPARATE STEAM GENERATION

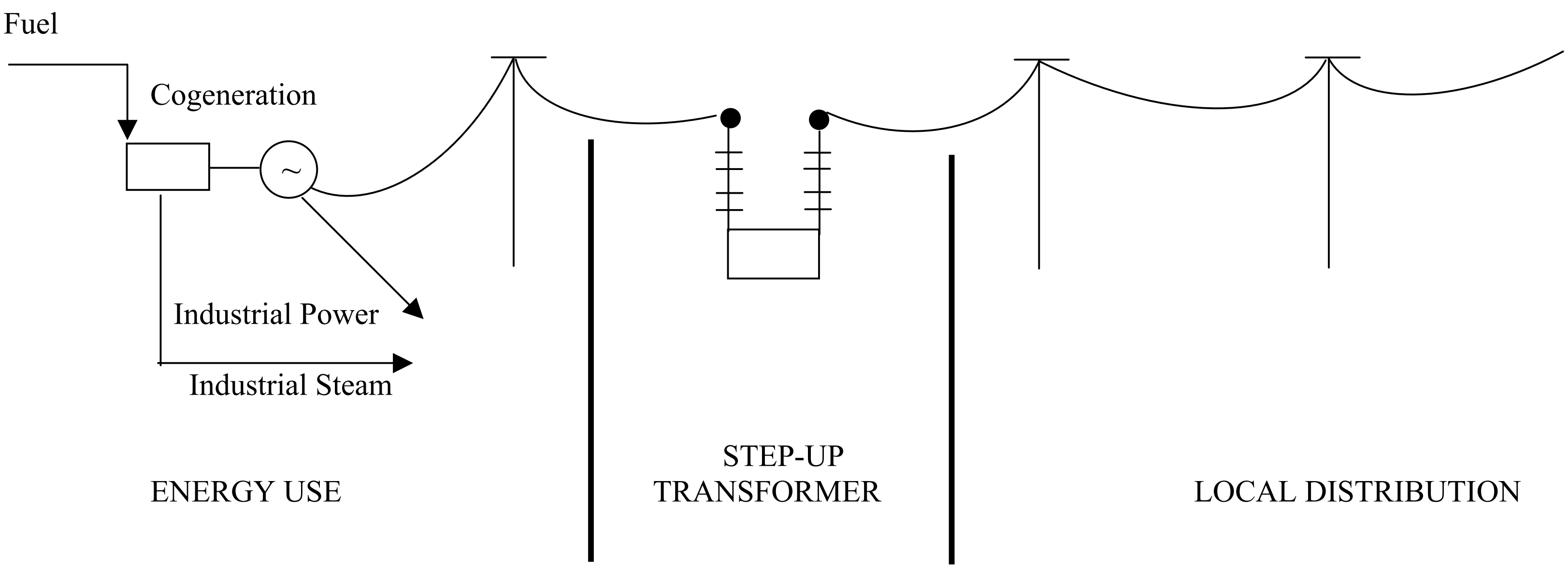

FIGURE 2
COGENERATION OF ELECTRICITY AND STEAM

High-Efficiency Distributed Cogeneration

This case, illustrated in Figure 2, is a nominal 50-MW gas turbine combined-cycle cogeneration facility designed to provide 150,000 pounds per hour (lb/hr) of steam to an industrial host. It is assumed that the facility will be located west of the Cascades at an industrial site that will use all the generated electricity and steam onsite.

The cogeneration system performance will be based on the Alstom GTX100 gas turbine. (Other gas turbines, such as the General Electric LM6000 and the Pratt & Whitney FT8, could also be used.) The steam turbine used will have one controlled extraction at 210 pounds per square inch gauge (psig) and will include a condenser that will allow the combined-cycle power plant to operate when the industrial steam demand varies from 0 to 150,000 pounds per hour. The system is designed to minimize the flow of steam to the condenser under normal cogeneration operation. In the evaluation, it is assumed that all of the electricity is consumed by the industrial host.

ASSUMPTIONS

The combined cycle is assumed to operate at full load for 8,040 hours per year. This would represent a capacity factor of 91.8 percent, which is a high level of performance for large combined-cycle power plants. Of course, such facilities operate in response to market demands, so the actual capacity factor could be lower. If the combined-cycle operates at a lower capacity factor, the fixed cost per kWh would be higher. In the Pacific Northwest, thermal power plants are not normally operated during the spring and early summer months because of abundant sources of inexpensive hydro-electric power. Because of this, it is optimistic to assume 8, 040 hours of annual operation.

The cogeneration plant is assumed to operate at full load 8,400 hours per year. This represents a 95.8 percent capacity factor. This is a reasonable assumption because industrial cogeneration facilities normally operate at high levels of availability to match the operation of the industrial host. Also, it is assumed that no market sale or purchases of electricity are made. The economic comparison assumes a 20-year economic life, a 50-50 debt to equity ratio, debt interest of 7 percent and an equity rate of 14 percent. The burner tip cost of fuel is assumed to be $3.00 per MMBtu.
In the process of making any comparison, a number of assumptions must be made. The specific details of any project will vary somewhat from those presented here. However, it is believed that the fundamental conclusions reached generally will not change even with changes in the assumptions.

SUMMARY OF CONCLUSIONS

The fundamental conclusion of this comparison is that high-efficiency distributed cogeneration is substantially more energy efficient and economical compared with large, remote, combined-cycle power plants. The cogeneration case produces lower emission levels, consumes less water, and distributes these impacts over a wider geographic area.

Energy Efficiency

Cogeneration requires 33 percent less fuel than does a remote combined-cycle power plant to produce one megawatt-hour (MWh) of delivered electricity. The higher efficiency is attributed to a higher thermal efficiency (about 29 percent) and to the elimination of transmission and distribution (about 4 percent). The higher thermal efficiency for cogenerated power results because a portion of the fuel used is allocated to steam production.

This allocation is based on the fuel required to produce an equivalent amount of steam in an industrial boiler. On the basis of this allocation, the cogeneration heat rate is 4,781 British thermal units (Btu/kWh). The heat rate for the combined cycle is 7,140 Btu/kWh for delivered energy.

Delivered Energy Cost

The cost of delivered electricity from a cogeneration facility is significantly less than the cost of electricity produced and delivered from a remote combined-cycle power plant. The estimated costs per MWh of delivered energy are summarized in Table 1 for both cases.

TABLE 1
Estimated Electricity Costs
$/MWh Delivered

Variable Costs	Combined Cycle	Cogeneration
Fuel Costs	$21.42	$14.34
Nonfuel Operation & Maintenance (O&M)	$5.21	$5.00
Transmission Wheeling	$5.21	$0.00
Local Utility Delivery	$10.00	$0.00
Total Variable Costs	$41.83	$19.34
Total Annual Fixed Costs – Power Plant	$10.28	$18.91
Total Electricity Costs	$52.11	$37.27

The total variable cost for cogenerated electricity is less because of the more efficient heat rate and the absence of wheeling and local delivery charges. The fixed cost for the combined-cycle facility is less than that for cogeneration primarily because of the economy of scale for a large power plant. The total annual fixed costs shown in Table 1 do not include the capital costs for the required new transmission. Assuming 100 miles of new 230 kV transmission lines and the associated substation could add between $100 million and $150 million to the capital cost or between $3.69 and $5.54/MWh. If new transmission facilities are required, the cost advantage of the cogenerated electricity is even greater.

Air Emissions

A comparison of nitrogen oxides (NO_X), carbon monoxide (CO), and carbon dioxide (CO_2) emissions for the combined-cycle and the cogeneration facilities is shown in Table 2. The emissions for the combined-cycle facility are based on best available control technology (BACT). The NO_X emissions are 2.5 parts per minute (ppm) and the CO emissions are 5.0 ppm. The emissions for the cogeneration facility are the same (i.e., 2.5 ppm NO_X and 5.0 ppm CO). In addition, the cogeneration emissions are reduced by the displaced emissions that would be produced in an industrial boiler producing an equivalent amount of steam (150,000 lb/hr). The industrial boiler emissions were calculated using U.S. Environmental Protection Agency (EPA) AP-42 emission factors. As noted in Table 2, this would result in a net reduction in NO_X and CO emissions at the industrial site. This occurs because the cogeneration emissions are two orders of magnitude lower than those for the industrial boiler.

The CO_2 emissions for the cogeneration system are also reduced by the equivalent emissions that would be produced by a displaced industrial boiler. The CO_2 emissions are approximately 67 percent of those from a combined-cycle power plant per MW of capacity.

TABLE 2
Emission Comparison

Emission Factor	Combined Cycle	Cogeneration
Net Delivered Capacity MW	439	48.0
Net NO_X, lb/hr	31.0	(24.5) [a]
Net NO_X, lb/yr/MW	574	(480) [a]
Net CO, lb/hr	38	(11.6) [b]
Net CO, lb/yr/MW	459	(2030) [b]
Net CO_2 , tons/hr	200	14.2 [c]
Net CO_2, tons/yr/MW	3,683	2,485 [c]

Notes: a. Cogeneration NO_X emissions include a credit of 29.5 lb/hr for displaced boiler emissions for the single 48-MW facility.
b. Cogeneration CO emissions include a credit of 17.6 lb/hr for displaced boiler emissions for the single 48-MW facility.
c. Cogeneration CO_2 emissions include a credit of 12.6 tons/hr for displaced boiler emissions for the single 48-MW facility.

Water Consumption

The makeup water requirement and wastewater per MW of delivered energy for the cogeneration system is only approximately 70 percent of that for the combined-cycle plant. This is attributed to the higher thermal efficiency of the cogeneration facility. Only approximately 25 percent of the steam generated in the cogeneration facility is condensed compared with 100 percent for the combined-cycle plant. This results in a significant reduction in evaporative water consumption.

Approximately nine cogeneration facilities would be required to generate the same output as the combined-cycle power plant. This demonstrates the important advantage of distributed cogeneration: it consumes less water and distributes the needed water geographically close to the energy load centers.

DISCUSSION

The cost and performance basis for this comparison are described below. This includes the performance, capital costs, and operation and maintenance costs of the generation facilities.

Performance

The performance of both cases is summarized in Table 3. This includes the gross and net output, transmission losses, and net delivered power and annual energy. The heat rates for both cases are calculated on the basis of the gross heat rate and the heat rate for net delivered energy. The cogeneration system heat rate also includes a credit for the thermal energy supplied to the industrial host. The cogeneration heat rate (4,781 Btu/kWh) is approximately 33 percent less than the combined-cycle heat rate (7,140 Btu/kWh).

TABLE 3
Comparative Performance

Capital Cost Factors	Combined Cycle	Cogeneration
Gas Turbine Output – Kw	302,000	43,430
Steam Turbine Output – Kw	168,000	6,460
Gross Plant Output - Kw	470,000	49,890
Plant Auxiliary Loads and Degradation	12,790	1,879
Net Plant Output – kW	457,210	48,011
Step-up Transformer Losses – kW	2,289	0
Transmission Losses – kW	13,648	0
Step-Down Transformer Losses – kW	2,206	0
Net Delivered Power – kW	439,070	48,011
Gross Annual Energy Produced - MWh	3,778,800	419,076
Net Annual Energy Produced - MWh	3,675,968	403,293
Annual Energy Delivered – MWh	3,530,122	403,293
Annual Steam Produced -1,000 lb	0	1,300,320
Gross Gas Turbine Heat Rate - Btu/kWh (HHV)	10,380	10,236
Gas Turbine Thermal Input - MMBtu/hr	3,134	444.6
Thermal Input to Industry - MMBtu/hr	0.0	215.0
Net Thermal Energy for Power - MMBtu/hr	3,134	229.6
Net Cogeneration Heat Rate – Btu/kWh (HHV)		4781
Net Combined-Cycle Heat Rate – Btu/kWh (HHV)	6,856	
Net Delivered Energy Heat Rate – Btu/kWh (HHV)	7,140	4,781`

Capital Costs

The capital costs for the combined-cycle power plant and the cogeneration facility are shown in Table 4. The capital cost for the combined-cycle plant includes the engineering, procurement, and construction (EPC) costs, the Owner's development costs, and transmission infrastructure costs. For this comparison, the EPC costs for the combined-cycle plant are assumed to be $215 million (approximately $470/MW of gross output). The Owner's costs include Owner's management and legal costs, development expenses, financing, contingency, interest during construction, startup, commissioning, and initial working capital. The Owner's costs are assumed to be 30 percent of the EPC costs, or $65 million. The total costs are estimated to be $280 million. The transmission infrastructure costs could range from $100 million to $150 million for 100 miles of 230-kV, single-circuit transmission line and substation facilities. These costs are not included in Table 4.

The EPC cost for the cogeneration facility is $45 million. The Owner's costs are also taken at 30 percent of the EPC cost, or $13.5 million, for a total cost of $58.5 million. No transmission infrastructure costs are attributed to the cogeneration case.

The capital costs for both alternatives are reasonable and in the range of similar facilities installed over the last 3 years. The actual capital costs for a specific facility could vary by ± 30 percent. However, this will not change the fundamental conclusion reached in this paper.

TABLE 4
Capital Costs ($000)

Capital Cost Factors	Combined Cycle	Cogeneration
EPC Costs	$215,000	$45,000
Total Owner's Costs	$65,000	$13,500
Total Estimated Costs – Power Plant	$280,000	$58,500
Unit Total Costs ($/kW delivered)	$637	$1218

Annual Variable and Fixed Costs

The annual variable and fixed costs for each case are summarized in Table 5. The annual variable costs include fuel costs, fuel cost credit for cogenerated steam supplied, nonfuel O&M, transmission wheeling, and local delivery. The annual fixed costs include debt service and equity returns.

The nonfuel O&M costs are assumed to be $5.00/MWh of power produced. This is on the high end, and the combined-cycle plant may be able to operate below this cost level. However, it makes little difference.

The local delivery costs reflect the local utility costs, including taxes and public purposes charges, for delivering electricity to local industrial customers.

TABLE 5
Annual Variable and Fixed Costs ($000)

Variable Cost Factors	Combined Cycle	Cogeneration
Annual Fuel Costs	$75,612	$11,202
Annual Fuel Costs Credit for Steam	$0	($5,418)
Annual Fuel Costs for Electricity	$75,612	$5,785
Annual Nonfuel O&M @ $5.00/MWh Produced	$18,380	$2,016
Transmission Wheeling @ $5.00/MWh Produced	$18,380	$0
Local Utility Delivery @ $10.00/MWh Delivered	$35,301	$0
Total Variable Costs	$147,673	$7,801
Total Annual Fixed Costs – Debt and Equity	$55,840	$7,230
Total Annual Costs	$203,513	$15,031

Energy Unit Costs

The variable and fixed costs per MWh of delivered capacity are summarized for each case in Table 1. The variable costs per MWh of delivered electricity for the combined-cycle case is almost 50 percent more than those for the cogeneration case. This is clearly attributed to the higher fuel efficiency of the cogeneration system, the transmission losses, and the cost for wheeling and local utility delivery.

The fixed cost for the combined-cycle case is less than the fixed cost for the cogeneration case. This is attributed to the economy of scale for the large combined-cycle plant; however, the high cost for transmission facilities contributes about one-third of the combined-cycle fixed cost and reduces its advantage.

A significant conclusion is that fuel efficiency and an absence of wheeling and local delivery charges are much more important than capital costs. Even if no transmission improvements are required, the cogeneration system is still more attractive.

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