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A METHODOLOGY FOR ASSESSING ALTERNATIVE WATER-
ACQUISITION-AND-USE STRATEGIES FOR ENERGY
FACILITIES IN THE AMERICAN WEST

by

John J. Shaw, E. Eric Adams,
Donald R.F. Harleman and David H. Marks

Energy Laboratory Report No. MIT-EL 81-051

December 1981

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ABSTRACT

This report develops a method for assessing alternative strategies for acquiring and using water at western energy plants. The method has been tested in a case study of cooling water use for a hypothetical steam electric power plant on the Crazy Woman Creek, an unregulated stream in Wyoming.

The results from the case study suggest a careful analysis of reservoir design and water right purchase strategies can reduce the cost of acquiring and using water at an energy facility. The key to this advance arises because water is not a homogeneous good: different sources will deliver water with different costs and different reliabilities. This occurs because water supplies are sensitive to seasonal changes. The methodology recognizes this seasonal component in supply and searches for optimal (or 'non-inferior') tradeoffs between conserving water in the plant cooling system, building larger reservoirs, and purchasing existing water rights.

The method uses simulation models to assess the capital and operating costs and expected monthly water consumption rates for different cooling system designs. The method also uses reservoir operating algorithms to select, for a fixed cooling system design, the optimal tradeoff between building a make-up water reservoir and purchasing water rights. These tradeoffs can be used to derive the firm's true demand curve for different sources of water. The analysis also reveals the implicit cost of selecting strategies which minimize conflicts with other water users.

Three noteworthy findings are revealed for the single case study, though it appears these findings will hold for other small, unregulated rivers where some fraction of the flow remains unappropriated by existing users:

1. Cooling ponds are as good as or preferred to wet towers because their costs already include provisions for storing water for use during the normally dry summer months and during occasional drought years.
2. The energy firm's demand for overall water consumption in the cooling system is inversely proportional to both the cost of installing make-up water reservoirs, and the size of the energy facility.
3. The firm's willingness to pay for existing rights is proportional to both the cost of installing reservoirs, and the size of the energy facility.

Taken together, these last two findings suggest an energy firm's demand for water in general and its demand for existing water rights in particular can move in opposite directions. Contrary to recommend-

ations seen elsewhere in the literature (Bishop and Naryanan, 1978), it does not necessarily follow that water should be transferred away from alternative uses to energy simply because energy firms can pay premium prices for the total water their plants consume.

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Many friends contributed to my education and, not the least of all, to my moral support. To Ming, Pete, Fred, Mark, Dianna, and Roger: I thank you for all of our good times. Special recognition must go to Pedro for frequently snatching me to safety moments before the slavering maw of the IBM was about to snap shut on me. And not the least in this list are my favorite partners in crime, Dave and Hans. I think between the three of us we pretty much solved the pressing issues of the day.

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J.J. Shaw

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CHAPTER 1 INTRODUCTION

1.1 BACKGROUND

The prospects for large-scale development of energy reserves in the western U.S. raises the concern that the demand for water for energy will compete with other uses. On many unregulated rivers the entire streamflow is often exhausted by existing users during the summer months. New claims to water are also appearing--for example instream flows and Indian and Federal reserved water rights--which if met could significantly reduce the amount of water available for energy development in a number of river basins (e.g., the Tongue river basin in Wyoming and Montana). Water allocations for new western energy programs may pre-empt some new uses, and may involve the transfer of water away from some existing users as well. Many of these alternative uses are for environmental purposes while others support the bulk of economic activity in the western states. From the perspective of the western states the social value of water often exceeds the direct economic benefit of its use in any one activity. In those areas where water is scarce relative to demand energy companies will need to demonstrate that they can use water effeciently and in a manner which minimizes conflicts with other activities.

An energy firm may obtain water from any of a number of sources, including direct diversions from local rivers, groundwater, municipal sewage, and water imported from other river basins. Water from these sources may be unappropriated by other users, or it may be assigned to

an existing use, in which case the firm must purchase the water from the current owners. In many cases the firm may install a reservoir to capture the peak flows in a river that would otherwise go unused. With a reservoir on hand the firm has greater latitude in deciding when to divert water from a river. By diverting and storing water during the Fall and Spring the firm can reduce potential conflicts with other users on the river during the Summer when demand often exceeds the available supply.

The energy firm can also reduce water consumption thru changes in the plant design. One of the most logical places for design changes is in the cooling system, where up to 80% of the water consumed at the plant is lost. Of the alternative cooling systems available some can operate with reduced water consumption, some with greater flexibility with when the plant must divert water from the river, and some with both qualities. These qualities are obtained at a cost, however, and one of the key tasks in developing a water management plan for an energy plant is to balance these costs against the costs of acquisition.

1.2 OBJECTIVES OF THIS STUDY

This thesis presents a methodology for assessing alternative strategies for acquiring and using water at a western energy facility. This method can identify desirable strategies from any of a number of objectives. For example, the objective may be to find a strategy having the least cost to the energy firm, or it may be to minimize potential conflicts with existing water users in a river basin. This assessment

may also be used to quantify the firm's willingness to pay for different types of water.

For an energy firm the impetus for analysis of this sort is clear enough: it must make a financial commitment for plant and equipment as well as bear all foreseen and unforeseen risks accompanying a particular strategy for acquiring and using water. The firm's willingness to pay for water may also be compared with the willingness to pay for water in alternative uses. Thus this analysis lends itself to the broader public policy issues of finding 'acceptable' water allocations among the competing claimants in the West.

The methodology combines different plant design and water acquisition alternatives with factor costs to define acceptable strategies for acquiring and using water at an energy facility. Water use promotes better plant operating efficiencies (a benefit), while water acquisition incurs a cost. The costs of acquisition arise in large part because water availability is often stochastic in nature and because water acquisition is frequently subject to institutional restrictions. This methodology exploits these points by examining the tradeoffs between designing the plant cooling system to consume greater or lesser amounts of water, installing a reservoir to capture streamflows for drought periods, and purchasing water from existing users. This method weighs, for a set of strategies, the benefits of water use against the costs of its acquisition. From this set the method identifies a sub-set of non-inferior strategies. These non-inferior strategies may be defined such that each one represents a point on the firm's demand curve for water.

The method has been tested on a case study of cooling water needs for a hypothetical steam electric power plant on the Crazy Woman Creek, Wyoming.

1.3 OUTLINE OF PRESENTATION

Chapter 2 identifies some of the problems of acquiring and using water in the West. Here we briefly examine a number of the factors influencing the supply of water to western users, its demand in non-energy uses, and its demand in energy. The methodology is introduced in this chapter as well. Chapter 3 examines the cooling system alternatives for an energy facility. Design parameters and simulation models are presented here. Chapter 4 presents the models used to simulate and optimize reservoir operation. The methodology is demonstrated in Chapter 5 where we present the results from the case study. Non-inferior strategies for acquiring and using water are evaluated to define the firm's demand schedule for water in general and for existing water rights in particular. Chapter 6 summarizes the research effort, presents conclusions on the method, particularly with regards to its applicability, and suggests directions for future research.

CHAPTER 2   ISSUES OF WATER SUPPLY/DEMAND IN THE WEST

2.1   INTRODUCTION

In this chapter we will try to put the problem of allocating western water for energy use in some perspective. Specifically, we will examine a number of the features of western water supply that are relevant to the allocation of water to energy. Water is not a homogeneous resource, and as we shall allude to in this chapter and then demonstrate later in this thesis, solutions to the water allocation problem may be found if we shift the emphasis from who gets water to who gets what types of water. An energy firm may obtain water from any of a number of sources including direct diversions from local rivers, groundwater, municipal sewage, and water imported from other basins. For any one of these sources the energy firm must assess the available supply and the costs of acquisition. Finally, and by no means a trivial effort, the firm must assess its own demands for water. Three aspects of western water are integral to our understanding of the water situation confronting new energy development: a) the supply of water; b) the demand for water in non-energy related uses; and c) the demand for water for energy related uses.

2.2   THE SUPPLY OF WESTERN WATER

There are two facets of western water supply that require our understanding: the physical presence of the water itself, and the institutional arrangements that dictate how water is allocated among competing users. We will begin by examining the physical presence of water.

2.2.1 SURFACE WATER HYDROLOGY

Snowmelt runoff is the primary source of water for most rivers and streams in the West. An examination of a representative annual hydrograph for an unregulated stream (Figure 2.1) reveals that river flows are low during the winter, reach their peak in the spring when the snowmelt enters the river, and recede during the summer and fall. In addition, the virgin flows on unregulated rivers may be highly variable from one year to the next. On the Powder River, for example, the average annual surplus flow (water remaining after existing uses are accounted for) belonging to the state of Wyoming is roughly 121,000 acre-feet/year (Trelease, 1977). In a low water year, however, there is usually no surplus flow.

While a number of the western energy reserves are located near or on regulated rivers (e.g., reserves in the Green River basin formation, Wyoming, in the San Juan river basin, New Mexico, and the reserves adjacent to Lake Powell in Utah), some of the richest deposits lie in basins having unregulated rivers. These include the vast coal reserves flanking the Powder, Tongue, and Belle Fouché rivers in Montana and Wyoming, and the high-grade oil shale and coal deposits along the White River in Colorado. On some of these rivers up to 70% of the average annual runoff will come in the four month period from April to July (U.S.G.S., 1930-1968). During extreme years anywhere from 60-70% of the flow will come in May and June. That flows on unregulated rivers can appear in such a skewed fashion should make us suspicious of 'available' water measurements based on annual flows alone.

Figure 2.1 Representative Hydrograph for a Small Stream in the Western United States [Crazy Woman Creek; 1977 Water Year]

Nevertheless, previous studies assessing the probable impacts of future energy development on western water have frequently used average annual river flows as a measure of the amount of water available for use. Bishop, et al., (1975) used annual average flows in their assessment of water use/energy development tradeoffs in the Colorado River Basin. Buras (1979) used regional average annual water supply measurements in his nation wide macro-economic model used to quantify the effect of water availability constraints on energy development. Probst and Gold (1978) used average annual flows to assess water availability in some river basins and historical low flows to assess availability in others without recognizing the distinction between the two types of measurement. The water assessment studies by the Northern Great Plains Research Program (1974) and the Colorado Department of Natural Resources (1980) are among the few studies that have addressed the problem of supplying water to future energy projects during low-flow years.

2.2.2 INSTITUTIONAL CONSIDERATIONS

In many respects, the problems of water availability associated with the physical scarcity of western water pale beside the restrictions imposed by institutional constraints, for it is these constraints that will in fact dictate how much water will be allocated to new energy development. Interestingly enough, however, one frequently finds that many of the institutional considerations are addressed in an off-hand manner in the literature, reflecting an optimism that what man has done, he can readily undo. This is not entirely correct for all institutional constraints

actually exist within some hierarchy, and some are more readily removed (or circumvented) than others. The important institutional factors in the West range anywhere from laws written into state water codes to the ideologies of various interest groups, with the former carrying greater weight than the latter.

The foundation for all the institutional constraints on western water supplies is the appropriations doctrine, the doctrine by which almost all western waters are allocated to users. Under the 'riparian code' practiced in the eastern United States the owner of a parcel of land adjacent to a water-course has an automatic right to use some portion of the water in that stream. By contrast, under the appropriations doctrine the right to use water from a particular stream is determined by the possession of deeds or permits that specify the maximum flows, e.g. in cfs, right holders may divert from the stream. These rights are separate from the ownership of land adjacent to the stream. Water rights are recognized as quasi-property rights that may be used and transferred among individuals, subject to certain restrictions. Along any stream water is distributed first to the most senior (or oldest) rights, with the most junior rights served last. As a consequence senior right holders receive their water with greater frequency and greater predictability than junior right holders. It is, in part, for this reason that we will seek solutions to the problem of allocating water to energy by broadening our scope from a question of 'who gets water' to include the question of 'who gets what types of water'.

Western water is considered a public good and individual right holders themselves merely have permission to use the water decreed by their rights.

Through the administration of water rights programs the western states control all water not claimed by the Federal government, and frequently have the authority to allocate water stored behind dams built by the Bureau of Reclamation as well. In addition, the McCarren Amendment of 1952 allows western states to settle unresolved Federal claims to water in state courts where state water laws are already recognized. As a consequence the bulk of western water supplies, with the exception of Indian water rights and undisputed Federal water rights, are under direct and indirect state control.

The western states administer water rights on the basis of two broad notions: all water must be put to beneficial use, and all legitimate water users are protected from losing their rights without due process. Both notions date back to the origins of the appropriations doctrine and in some instances are explicitly written into state constitutions. It is highly unlikely either notion will be abandoned, and consequently water use for energy development will be required to satisfy all tests relevant to these principles.

All western states require that water be put to beneficial use: 'The beneficial use of water is the basis, the measure, and the limit of a water right' (NGPRP, 1974). Western states recognize both economic and non-economic (e.g. aesthetic, recreational, environmental) measures for beneficial use (Riggs, 1975; Burness and Quirk, 1976; Hendrickson, 1978). In addition, many western states consider some uses to have 'superior benefits' to others and will not allow the transfer of water from a superior use to an inferior use. Domestic water supply and irrigation are

treated as superior uses to energy in a number of western states. There is a widely-held feeling in these states that water in agriculture confers secondary benefits to their regions which would not be found were the water to go for energy. It is important to note, however, that the relative importance assigned to a particular use reflects economic conditions that can evolve with time. The current restrictions against the transfer of water from agriculture to energy may eventually disappear as the energy industry matures and assumes a larger role in the western economies.

From the states' point of view there is a strong distinction between benefits that accrue to their region and those that accrue to the nation as a whole. This distinction, however, has not always been properly acknowledged in previous assessment studies. In their evaluation of the benefits of water use for energy development in the lower Colorado River Basin, Bishop and Naryanan (1978) confused economic efficiency (e.g. national income) with social benefits (e.g. regional income). Gisser, et al., (1979), on the other hand, recognized both regional and national income benefits in assessing impacts from future energy development in the Four Corners area.

All western water laws forbid right holders from changing the use and/or the location of the diversion point of their water rights in such a manner as to injure other water users in the vicinity. The potential for injury is found most frequently in cases where one right holder had historically returned some fraction of the right's diversion back to the river (through drainage canals, seepage, etc.) where it was available for use by junior right holders downstream. Changes in the use and/or location

of the diversion point of a right are generally confined to the fraction of the diversion that had been consumed historically; the remaining fraction of the original diversion (the historic 'return flow') cannot be altered and must continue to be available to downstream users. Western irrigators typically return from 50%-70% of their diversion back to the river, meaning for all practical purposes that energy companies may find they will receive only 50%-30% of the adjudicated flow from a right they have purchased.

The proof of non-injury is often an costly and time-consuming process which frequently demands extensive hydrologic analyses in addition to court appearances, or hearings, before local water administrators. The non-injury provision is a feature of all western laws, and unlike the notion of beneficial use, which is open to re-interpretation in the light of changing economic conditions, it is a nonnegotiable feature.

2.2.3 ALTERNATIVE SOURCES OF WATER

There are alternative sources of water for western energy development beyond direct diversions from local streams and rivers. Unfortunately it is beyond the scope of this thesis to assess the features of all probable sources of water for energy in the West. In subsequent chapters we will examine exclusively the problems of developing surface water supplies for energy development. This is not to say that alternative sources of water should be overlooked in the development of a water management plan for any one plant. We will see later on that the costs of acquiring, storing, and treating surface waters may shift the balance in favor of alternative sources of water at specific sites.

We will briefly mention three alternatives to surface water: groundwater, municipal sewage, and interbasin water transfers. We begin with a look at groundwater supplies.

There are two major aquifers underlying the western coal and oil shale fields: the upper and lower Mahogany systems in the Upper Colorado River basin (Utah, Colorado, and Wyoming), and the Madison aquifer in the Yellowstone River basin (Wyoming and Montana). The location of these two aquifers with respect to the major western energy deposits is shown in Figure 2.2.

Well yields are highly variable in both the Mahogany and the Madison systems with output per well typically ranging from 1 to 4 cfs in the upper Mahogany and from 1 to 10 cfs in the Madison aquifer (Colorado Dept. of Natural Resources, 1980; Swenson, 1977). Estimates from both of these references regarding the costs of pumping and drilling suggest these yields are sufficient to make groundwater a competitive alternative to surface waters in a number of river basins. However, these estimates do not include the potentially large costs a groundwater user may incur to satisfy regulations affecting groundwater use. These regulations may include non-injury to other groundwater users in the area, assigning preference to municipal and irrigation withdrawals, and restrictions on any aquifer withdrawals that might adversely affect surface water right holders on streams connected to underlying aquifers. A case in point is the effort by Occidental Oil Shale, Inc. to use groundwater for its prototype oil shale plant in the Green River Basin. Several groups opposed its request for groundwater rights, arguing that surface waters fed by this aquifer would

FIGURE 2.2 LOCATION OF MAJOR WESTERN
AQUIFERS WITH RESPECT TO
WESTERN ENERGY DEPOSITS

be depleted as a consequence of the oil company's actions. A water court approved Occidental's request, but did so with the stipulation that the company would be required to monitor its effects on local surface water supplies and compensate right holders who could prove they were injured as a result of the company's activities (Weatherford, et.al., 1980).

A second factor that could make groundwater costs higher than estimated stems from the uncertainty about future flow conditions in the two aquifers. There is insufficient knowledge about the hydrology of either system to predict whether current yields can be maintained for many years in the future (Colorado Dep. of Natural Resources, 1980; Swenson, 1977).

Reclaimed municipal sewage can be an attractive source of water for energy facilities located close to large cities and towns. Municipal sewage is the primary source of water for numerous steam-electric plants throughout the West including the Clark (190 MWe) and Sunrise (81 MWe) units in Nevada, and the Denton (188 MWe) and Braunig (885 MWe) units in Texas. Municipal sewage has also been proposed as the source of cooling water for two new generating stations: the Harry Allen (2000 MWe) plant in Nevada, and the Palo Verde (6350) plant in Arizona. Secondary treatment is usually sufficient if the sewage is used in processes where medium and low quality water is called for (e.g., the cooling system and fly ash disposal). Biocides and anti-fungal agents are often added to water used for cooling to prevent the build up of algae and bacteria in the plant condensers, piping and cooling system.

Two factors must be taken into account during any assessment of the feasibility of using municipal sewage at an energy facility. The first is

whether there is a sufficient supply of sewage water to make it economically competitive with respect to other sources of water. Many of the major western energy reserves are located in sparsely populated areas where municipal water demands represent only a small fraction of the total water use. The second factor involves resolving conflicting claims over ownership of the effluent leaving a treatment plant. In many cases a city's water supply is delivered by one agency and treated by another. Furthermore, the discharge from the treatment plant may reenter surface and groundwater supplies claimed by downstream users. Each of these three groups may claim the right to sell the discharged water, and disputes over ownership could result in unacceptable delays in the procurement of a facility's water supply. Unfortunately, western water laws are often ambiguous on this issue (Weatherford, et al., 1980).

Interbasin water transfers have been offered as one means to supply water to energy projects. The general scheme would be to build pipelines or aqueducts from a river basin where water is plentiful to basins having extensive coal or oil shale reserves but little water. Proposals range anywhere from constructing a series of aqueducts to connect Lake Oahe in South Dakota with Gillette, Wyoming, a distance of 300 miles, to relatively short transfers such as from the Powder River to Gillette (25-40 miles), and from the White River to Piceance Creek, Colorado (25-30 miles) (DOI, 1977; WPA, 1977; Colorado Dept. of Natural Resources, 1980). In all these proposals water could come from existing or new reservoirs on the source river.

There appear to be three points to consider vis a vis the

feasibility of supplying water through interbasin transfers. The first is the cost of building projects of this sort. We shall see later in this thesis that it might be cheaper to reduce the demand for water by selecting an alternative plant design than to transport water over long distances from one basin to another. The second point is that efforts to build new reservoirs to supply water for interbasin transfers may run into opposition from both state governments and local populations (Faulkner, 1976). The third point is that some interstate compacts expressly prohibit the transfer of water from one river basin to another.

The Yellowstone River Compact is a case in point. This compact, signed by Wyoming, Montana, and North Dakota in 1950, allocates the water in the Yellowstone River basin among the three states with the provision that no state may transfer any part of its allotment to an outside basin unless all three states agree to the transfer. The Belle Fourche river basin in eastern Wyoming has extensive coal reserves, is water poor, and lies just outside the Yellowstone basin. Under the terms of the compact water cannot be transferred from the Powder river, a tributary to the Yellowstone River, to the Belle Fourche basin, a distance of 30-40 miles. Whether Montana and North Dakota will agree to a waiver in this case remains to be seen.

2.2.4 SUMMARY

In summary, there are two features of western water supply that are relevant to the problem of obtaining water for energy. The first is the physical availability of water, which for streamflows may be highly seasonal and uncertain. The average annual flow of a river is generally an

insufficient measure for assessing water availability on unregulated streams. The second feature is the set of institutional factors that are used to allocate water among competing users. The appropriations doctrine is the foundation for all institutional arrangements, and operates within the two provisions that water be put to beneficial use, and that third party right holders are protected from injury as a result of a change in the use or the location of the diversion point of a right. While the measure of beneficial use is flexible and, in time, may place a higher emphasis on energy development than it does today, energy companies will be required to operate within the permanent, and possibly costly, restrictions found under the noninjury provisions.

2.3 THE DEMAND FOR WATER IN NON-ENERGY RELATED ACTIVITIES

The options available to an energy firm for acquiring water will be influenced in large part by the existing and potential demands for water in non-energy uses. As we noted in the last section the physical supply of water on unregulated rivers may be highly variable, and on numerous rivers throughout the West existing uses frequently deplete the entire flows during the summer months.

We have two reasons for recognizing non-energy water demands. On the one hand these uses may directly compete with energy for existing supplies. On the other hand an energy firm may purchase water from existing users to meet its own demands. Two characteristics of non-energy water demand deserve our attention: a) how these demands are seasonally distributed vis a vis the physical supply, and b) the implicit value of water in these uses.

2.3.1 SEASONAL DEMAND PATTERNS

The predominant water use in the West is for agriculture. In the western coal-bearing states irrigation accounts for approximately 90% of the annual man-induced water consumption (WRC, Part V, 1978). Additional uses for water are domestic water supply, recreation and wildlife protection, and mining (Hendrickson, 1978; Dewsnap and Jensen, 1977).

The demand for water is very time dependent, reflecting the overwhelming effect of seasonal irrigation demands. Figure 2.3 illustrates a representative water demand pattern for the hydrograph displayed in Figure 2.1. We note that the peak demand appears during the Spring and Summer months, corresponding to typical irrigation seasons which run from April to October (Jensen, et al., 1973; Anderson, 1975; Maass and Anderson, 1978; Gisser, et al., 1979). Water demands during the Fall and Winter months represent nonagricultural (e.g., municipal) uses. The peak irrigation demand in most river basins occurs during the receding stages of the river hydrograph; on many moderately sized streams the entire flow is frequently diverted for irrigation during the summer.

The degree to which the use of average annual measurements of water supply and demand can misrepresent the true water situation in some river basins is aptly demonstrated in a recent report on western water availability prepared by the General Accounting Office (1980). In this report the GAO used the results from a Colorado Dept. of Natural Resources study (op. cit) to conclude there is sufficient water, on average, in the Upper Colorado River Basin to meet the water demands for energy under a 'most probable' scenario of development without having to reduce other projected

FIGURE 2.3 REPRESENTATIVE HYDROGRAPH AND IRRIGATION
WATER DEMANDS FOR A SMALL STREAM IN THE
WESTERN UNITED STATES
(CRAZY WOMAN CREEK, 1977 WATER YEAR)

(non-energy) uses. The GAO study, however, failed to recognize that irrigation demands will deplete streamflows during the summer months to the point where new reservoirs will be needed on a number of tributaries for this conclusion to hold.

2.3.2 THE VALUE OF WATER IN CURRENT USES

With irrigation accounting for roughly 90% of all western water consumption there is a general consensus that if water rights are transferred to energy they will come from this sector (Trelease, 1976; Bishop and Naryanan, 1979; Hudson, 1978; Goslin, 1977). By contrast, domestic water use is expected to increase to accommodate new residents drawn West by energy development and there is little evidence to suggest that municipalities, having problems of their own acquiring new rights, will sell water to energy developers.

The value of water in agriculture serves as a lower bound on the price an energy firm can expect to pay for irrigation water rights. There are three measures of the value of water, each relevant to a particular transfer agreement between the seller and the buyer. The first is the 'shortrun' value of water, a measure of the farmer's willingness to pay for additional water after crops have been planted but before they have been harvested. This measure is relevant for the case where an energy firm temporarily 'rents' an irrigator's right at some point during the irrigation season. The second measure of value is the 'medium-run' value of water, which reflects the farmer's willingness to pay for additional water for the upcoming irrigation season but before crops have been planted. Like the

short-run value, this measure is relevant for the case where an energy firm temporarily rents irrigation water for the upcoming irrigation season, but secures this arrangement at the start of the irrigation season. The third and final measure is the 'long-run' value of water in irrigation, the compensation a farmer would demand to relinquish some water rights forever. These three measures of value represent three separate levels of financial commitment by the farmer. In the short-run the farmer not only has land, equipment, labor, and certain irrigation practices committed to production, but has planted crops committed as well. In the medium-run the crops are not yet committed, and in the long-run neither crops, labor, nor irrigation practices have been committed to production, nor in some cases the land and equipment as well. In actual practice the short-run value of water is higher than the medium-run value which is, in turn, higher than the long-run value (Young and Gray, 1972). The medium-run value of water reflects the farmer's own expectations about water availability during the upcoming irrigation season, and for this reason will be a function of the short-run marginal value of water (Maass and Anderson, 1978).

The short-run marginal value of water in agriculture is not a fixed value, but is a function of both the type of crop being irrigated and the period within which it is applied during the irrigation season. Figure 2.4 illustrates a generic relationship between crop yield and short term moisture stress at different stages in the irrigation season for a typical crop. We find that a larger reduction in crop output may occur when transient stresses appear during the middle and late stages of growth (Anderson and Maass, 1971; Cordova and Bras, 1979). One implication is that the

FIGURE 2.4 GENERIC RELATIONSHIP BETWEEN CROP GROWTH AND MOISTURE STRESS

(Ref.: Anderson and Maass, 1977)

short-run marginal value of water in agriculture has a strong seasonal dependence. The duration of a particular moisture stress will affect crop output, and thus the short-run marginal value of water at any period will reflect the accumulated effects of water deliveries prior to that time. In addition, the productivity of water in irrigation generally increases with longer intervals between waterings. At some point the soil moisture will drop below a critical value (the wilting point) and the crop will perish if it is not irrigated. For all intents and purposes the value of water at that point will equal the entire net income that will be lost if the plants die (Young and Gray, 1972). Figure 2.5 illustrates one realization of the highly seasonal changes in the short-run marginal value of water (1975) for sugar beet, corn, and alfalfa production on a hypothetical farm in Wyoming (Anderson, 1975). One observation that stands out is the tremendous sensitivity of the marginal value of water to the type of crop grown. During dry years, in fact, farmers will typically withdraw water from low-valued uses, such as alfalfa, and rent it out to irrigators growing higher valued crops (Maass and Anderson, 1978). The contribution of water to crop production depends on so many other factors besides the seasonal effects (e.g. fertilizer use, irrigation timing, drainage, salinity) that any single estimate of its value, which Figure 2.5 is, can only serve as a guide to what to look for when trading off water for irrigation versus other uses. In actual practice farmers irrigate high valued crops with their most senior water rights and irrigate low valued crops, such as alfalfa, with water delivered with lesser reliability from junior rights. For an energy company the decision to purchase existing rights will very

FIGURE 2.5 ONE REALIZATION OF THE SEASONAL CHANGES IN THE SHORT-RUN MARGINAL VALUE OF WATER IN SUGAR BEET, CORN AND ALFALFA PRODUCTION

likely involve a tradeoff between purchasing senior water rights (commanding premium prices) versus purchasing junior rights (having relatively low value). We will return to this point in Chapter 5 where we will examine various means to determine the firm's own demand curve for water.

The marginal value of water in current uses serves as a lower bound on the price an energy company can expect to pay for an existing right. Transaction costs plus the seller's own perception of the buyer's 'willingness to pay' must be added in as well. Colorado municipalities have been purchasing irrigation water at prices up to \$ 2000/ac-ft (CDNR, 1980). Records compiled by Khoshakhlagh (1977) for water right costs in New Mexico between 1970-1975 show total one time costs ranged from \$80/ ac-ft to over \$10,000/ac-ft.

2.3.3 POTENTIAL NEW USERS OF WATER

In addition to the existing water uses in the West, there are new demands which, if met, could significantly diminish the amount of water available for energy development. These new demands include setting aside minimum instream flows to promote wildlife protection, setting aside water to meet Indian claims, and setting aside water to meet federal reserved rights for use in national parks and forests. Most western states have defined criteria to protect instream water uses, and a number of states already have provisions to reserve flows for instream uses (Dewsnup and Jensen, 1977). There are a number of legal issues concerning Indian and Federal reserved rights to water. These issues, including the types of purposes the water may be used for and the seniority of these rights, must

be resolved before the effect these claims will have on the remaining flows in a number of western rivers can be fully quantified. Until then, there will be considerable uncertainty surrounding estimates regarding the amount of water available for energy development (Veeder, 1976; Trelease, 1976; Thomas and Anderson, 1976).

2.3.4 SUMMARY

In summary, existing water demands must be accounted for when estimating the amount of water available for energy development. This is particularly critical for the summer months when irrigation demands may divert most, if not all, of the flow in any given river. In addition, the marginal value of water in existing uses--primarily agriculture--is time dependent and a function of the amount of water available at that time, the reliability of delivery, the use to which it is put, and the demand for its use. This suggests that the value of water cannot be properly assessed by 'average annual' measurements. Finally, new demands for western water are anticipated and until they can be quantified there may be considerable uncertainty behind any estimates on the amount of water available for energy development.

2.4 THE DEMAND FOR WATER IN ENERGY PRODUCTION

We will now examine the demand for water at a large scale energy facility such as a steam electric power plant, a coal liquifaction plant or a coal gasification plant. The purpose here is to briefly introduce the alternatives an energy firm may select in order to integrate its water

demands with the water demands of other users. Subsequent chapters will offer more rigorous analyses of these alternatives from both design and operating perspectives.

2.4.1 COOLING SYSTEM ALTERNATIVES

The primary water consumption in most synthetic fuel and steam-electric power plants is through evaporation in closed-cycle cooling systems. Closed cycle systems include cooling ponds, spray ponds and canals, fully evaporative (wet) cooling towers, fully dry cooling towers, and hybrid dry/wet cooling systems. Representative illustrations of a cooling pond, a wet cooling tower, a dry tower and a dry/wet cooling tower are presented in Figure 2.6

Cooling ponds are widely used in regions where large amounts of land are available. A 'standard' size energy facility, such as an 800 MWe coal steam electric power plant or a 50,000 bbl/day coal liquifaction plant will require a cooling pond in the range of 500-1000 acres to insure acceptable heat rejection (Najjar, et al., 1979; Adams, et al., 1978; Jirka and Harleman, 1979). Cooling ponds are relatively insensitive to transient changes in the ambient temperature and continue to operate efficiently on hot days. Spray systems may be added to increase the rate of heat dissipation, but operate with higher water losses. In addition, the operation of spray systems is not well understood, and they have yet to attract wide-spread popularity. In succeeding chapters we will consider only passive cooling ponds.

Fully evaporative cooling towers are the most widely used closed cycle

a) Cooling Pond

b) Wet Cooling Tower

c) Dry Cooling Tower

d) Dry-Wet Cooling Tower

FIGURE 2.6 SCHEMATIC OF A COOLING POND, WET COOLING TOWER
DRY COOLING TOWER AND A DRY-WET COOLING TOWER

cooling systems at large energy facilities today. Unlike cooling ponds evaporative towers do not require large land areas and can be installed at most sites. Wet towers are roughly economically competitive with cooling ponds and because they may be installed as modular units their performance can be predicted by the manufacturer with reasonable accuracy before installation (Croley, et al., 1975; Najjar, et al., 1979; Sebald, 1976; United Engineers, 1974). Like cooling ponds, fully wet towers consume large amounts of water-on the order of 8,000-10,000 acre-feet/year for an 800 MWe electric generating plant. This water must be supplied on a more or less continuous basis. Unless the plant has access to a storage reservoir the cooling tower water demands could conflict with other water users during the dry summer months.

Dry cooling towers consume little or no water, offering an advantage over other cooling systems in extremely arid regions. However the capital costs of dry towers are substantially higher than the capital costs of other cooling systems. In addition dry towers perform poorly on hot days, leading to severe reductions in plant operating efficiency (Choi and Glicksman, 1978; Fryer, 1976). Figure 2.7 compares the simulated plant output for a 1200 MWe steam electric plant operating with cooling ponds, fully wet towers and dry cooling towers. The plant operates at a consistent level with either the cooling ponds or the wet towers and will always meet a nominal plant demand of 1200 MWe. With dry towers the plant experiences exaggerated diurnal cycles in efficiency which reduces the reliable plant output to 1060 MWe.

Dry/wet cooling systems are hybrid combinations of fully dry and fully

Figure 2.7 Cooling System Transient Simulation
(summer 1970)

Ref: Najjar et al., 1979

wet cooling towers, dry towers and cooling ponds, or combined dry towers, wet towers and cooling ponds. These systems, on the average, consume less water than either cooling ponds or wet towers alone, although peak water use during the summer may be roughly equivalent. Drywet cooling systems may be operated at any time to conserve greater or lesser amounts of water by varying the amount of heat rejected through the wet portion of the cooling system. At one extreme the cooling system may be operated with no water loss by using only the dry towers, and at the other extreme the system may be operated to exploit the maximum possible cooling from the wet-side. Under the former condition the plant operates with a low thermal efficiency while under the latter the plant operates with both a high efficiency and a high water loss rate. Throughout this thesis we shall refer to the 'operating mode' of a dry-wet system as representing the relative heat loading on the dry cooling side and on the wet cooling side. One attractive feature of hybrid systems, then, is that plant operators are allowed greater flexibility in selecting water consumption rates to match, at any time, current water availability constraints, the demand for plant output, etc.

Operating costs for six cooling system designs are compared in Figure 2.8. The cost of water is not included here. The shaded bands for the three hybrid dry/wet cooling systems indicate the range of operating costs achievable under maximum and minimum annual water consumption rates. When water costs are nominal we find that dry/wet cooling towers are more expensive to operate than fully wet towers, but are less expensive than fully dry towers.

FIGURE 2.8 COMPARISON OF ANNUAL OPERATING COSTS
FOR REPRESENTATIVE COOLING SYSTEMS

2.4.2 MAKE-UP WATER RESERVOIR CONSIDERATIONS

If the natural water supply in the vicinity of a proposed energy facility is both stochastic and highly seasonal some amount of reservoir storage may be needed to insure a continuous, reliable source of make-up water to the cooling system. One of the advantages of using cooling ponds is that they have an inherent storage capability. For cooling towers, however, the required reservoir capacity will depend on the configuration of the towers and on the stochastic deliveries of water to the plant. For our purposes reservoir capacity will appear as a parameter in the overall cooling system design.

To provide supplemental storage for towers an energy firm may consider building a reservoir supplied by off-peak flows. The installation of either cooling ponds by themselves or reservoirs for cooling towers offers the firm greater latitude with respect to when it will divert water from a river. A firm may find that off-peak flows during the Fall and Spring are sufficient to supply water for the Summer months, and in this manner mitigate conflicts with the majority of other water users. Alternatively, access to a reservoir will enable the firm to purchase junior water rights in place of senior rights. As we noted before, junior rights are less reliable and consequently less valuable to other users than are senior rights.

There are then two approaches an energy firm may consider if it seeks to minimize conflicts with other water users: directly reduce water consumption through some use of dry cooling and/or storage to allow the plant greater flexibility in the timing of its withdrawals from the river.

To date most research efforts examining the economics of water conservation in energy production have emphasized the problem of minimizing annual water use. The underlying assumption in these studies is that the water, however limited on an annual basis, is present anytime a firm wishes to use it. Zaloudek, et al., (1976) and Hu and Engleson (1977) examined the economics of dry-wet cooling towers constrained to operate within a fixed water loss over the year. In both of these studies the wet cooling towers supplement dry cooling during the hottest air temperatures and are gradually turned off as the air temperature falls. Hu and Engleson noted that actual sites are likely to have variable streamflows throughout the year, but did not incorporate hydrologic variability in their optimization models. Guyer, et al., (1979) suggested one method to incorporate the use of storage in the operation of dry-wet cooling towers. Their approach, however, still emphasized the efficient use of a fixed supply of water (thus avoiding the question of storage design). In many river basins in the West, however, the concern over water use for energy may not be so much to minimize the average annual water consumption as it is minimizing withdrawals during certain seasons and possibly during severe drought events.

The remaining chapters of this thesis will present a methodology to assist designers in developing strategies for water acquisition and water use at western energy facilities. This method will emphasize the options available in the selection of: 1) the cooling system design, 2) the make-up water reservoir capacity, and 3) the acquisition of new and existing water rights for a single plant. For future reference throughout this thesis we

shall use the term 'water management strategy' to refer to a particular set of choices in each of these three areas. For the dry-wet cooling systems we will extend this definition to include the selection of an optimal cooling system/reservoir operating policy.

The methodology is a collection of five separate models: a water supply model; a cooling system simulation model; a reservoir simulation/water rights acquisition model; an operations model to select the optimal operating policy for a dry-wet cooling system design; and a cost-accounting model. Figure 2.9 illustrates how these models are interconnected under this methodology.

The water supply model calculates the amount of water the proposed plant will receive in any month. Deliveries to the plant depend on the streamflow for the month and on the number of water rights held by the energy firm. The output from this model is subsequently used in the reservoir simulation and dry-wet cooling system operations models. The model is described initially in Chapter 4 and then in greater detail in Chapter 5.

The cooling system simulation models are used to measure the monthly operating performance for the cooling system designs under inspection. The simulation models for the cooling pond and wet cooling tower designs calculate monthly cooling water consumption rates as well as the monthly plant energy output. The water consumption rates are, in turn, used in the reservoir simulation model while the monthly plant output is used to calculate annual operating costs in the cost accounting model. The simulation models for the dry-wet cooling systems are used to calculate the one-to-one relationship between monthly water consumption and the monthly plant

FIGURE 2.9 A SCHEMATIC OF THE LINKING OF THE FIVE MODELS USED IN THE METHODOLOGY

output. This data is subsequently used in the reservoir simulation and the operations models. Chapter 3 will describe the cooling system simulation models in greater detail.

The reservoir simulation/water rights acquisition model is used to determine the tradeoff between installing make-up water storage capacity and purchasing water rights for each cooling system. The algorithm begins with an initial reservoir capacity for the cooling system in question and simulates the monthly water levels in reservoir. Inflows to the reservoir come from the water supply model and the outflows come from reservoir evaporation plus the cooling system water consumption. This latter data comes from the appropriate cooling system simulation model. The algorithm then uses an iterative search procedure to find the least expensive collection of water rights the energy firm can acquire that will supply enough water to prevent the reservoir from running dry within a specified return period (e.g., 1 month every 20 years). The model repeats this process for different reservoir capacities to reveal the 'optimal' tradeoff curve between installing storage and purchasing water rights for the cooling system under inspection. This model is described in complete detail in Chapter 4.

The operations model is used to minimize the lifetime operating cost for dry-wet cooling system assuming the facility has a reservoir with a fixed storage capacity at its disposal and a set of water rights in its possession. There are a number of algorithms to choose from for this purpose, and we shall weigh their strengths and weaknesses in Chapter 4.

The cost accounting model sums up the combined capital and operating costs for each water management strategy. The capital investment includes

the cooling system, the reservoir and, for plants located offstream, the pipeline used to transport make-up water from the river to the plant site. The capital investment made in purchasing water rights can also be included here but we will treat these costs as an independent parameter with which to select the optimal management strategy for the energy firm. In addition, water and land are frequently sold together; in some cases this is the only way water rights may be purchased. The joint purchase of water rights and land could be attractive for a firm contemplating the option of purchasing water rights and building a reservoir on the newly purchased land. However, an energy firm's demand for land for a reservoir will be inversely proportional to its demand for water rights. In this thesis we shall treat the purchase of land for storage reservoirs separate from the purchase of water rights. The operating costs include the energy used to operate the cooling system, the energy used in the production process plus additional energy (if needed) to compensate for poor cooling system performance, treating the make-up water, and pumping of the make-up water in the event the plant is several miles from the stream.

The five models permit the plant designer flexibility in choosing which of the parameters making up a management strategy to optimize or study parametrically, and which to fix a priori. Five parameters will receive our attention:

1. Cooling system design: We will examine six separate designs, described in Chapter 3. While each design is fixed certain features, such as cooling system geometry, plant condenser, etc., have been optimized in previous studies. The interested reader is referred to Najjar, et al., (1979) for details.

2. Reservoir capacity: We will examine various capacities for each of the six cooling systems. Pond areas are fixed for systems using full or partial cooling ponds, leaving the active storage depth as the variable to be studied. Both the reservoir area and the active storage depth are variables for cooling systems using full or partial wet cooling towers. In addition, it is assumed that all ponds and reservoirs will be diked enclosures built off-stream (see below).
3. Water rights purchases: The selection of rights purchased for the plant will be optimized for each cooling system/reservoir capacity configuration using the reservoir simulation model described in Chapter 4.
4. Cooling system operation: This is fixed for the cooling pond and fully wet cooling tower systems. The operations models are used to optimize operation for the dry-wet cooling systems.
5. Plant design: The plant is a coal-fired steam electric power plant (base-load) with two alternative generating capacities installed at the plant. For the first alternative a single 800 MWe generating unit is installed at the site, and for the second alternative two 800 MWe units are installed. To avoid confusion throughout this thesis we will refer to all designs, reservoir capacities, water rights purchases and operating costs on a 'per generating unit' basis.

We adopt the assumption that all reservoirs and cooling ponds will be built off-stream for simplicity in illustrating the methodology. With this assumption we can ignore any problems associated with flood control below the site and inundation of the river valley above the site.

The extension of this methodology to other types of energy facilities, such as coal gasification and coal liquifaction plants, can generally be made with little or no modification to the models involved. The major modifications needed are in the treatment of the interaction between the cooling system performance and plant output in the cooling system simulation models and in the handling of plant operating costs. The operating costs for the steamelectric plant are for coal (boiler fuel) and for replacement energy purchases when the plant power output falls below the target output (or 'demand').

CHAPTER 3   COOLING SYSTEM OPERATION

3.1   INTRODUCTION

The models used to simulate and measure the performance characteristics of alternative cooling system designs will be presented in this chapter. These models were originally developed by a number of investigators. The fully wet cooling tower model used here is a variant of a model developed at the University of Iowa (Croley, et al., 1975). The cooling pond model was developed from earlier studies done at MIT (Jirka, et al., 1978; Adams, et al., 1979; Ryan and Harleman, 1973; Jirka and Watanabe, 1978) as was the dry-wet cooling tower model (Choi and Glicksman, 1979). Additional references on cooling system models and their performance features may be found in Cheng, et al., (1976), Dickey and Cates (1973), Espey, Huston and Associates (1977), Hu and Engleson (1977), Larinoff and Forrester (1977), and Larinoff (1977). This chapter will also introduce the design and operating parameters used in the cooling system simulations. Finally, results from the simulation algorithms will be presented and the chapter will conclude with an analysis of these results and discuss how the different cooling systems lend themselves to further optimization efforts.

3.2 COOLING FUNDAMENTALS

Closed cycle cooling systems operate by circulating large quantities of water between the plant, where heat is added, and the cooling system heat exchangers, where heat is rejected to the atmosphere. The rate at which heat is generated by the plant is governed by the operating temperature. The rate at which heat is rejected by the cooling system is governed by the temperature within the cooling system and a number of ambient meteorological conditions which affect different cooling systems to a greater or lesser degree.

The stable plant operating condition is when the rate at which the plant generates heat is equal to the rate at which the cooling system rejects heat. At any time during operation, however, the ambient environmental conditions are fixed and thermal equilibrium occurs through a shift upward or a shift downward in the plant operating temperature. As the ambient meteorological conditions become less favorable for cooling the plant temperature must rise to establish thermal equilibrium. This principal is demonstrated in Figure 3.1 for a steam-electric turbine operating with a fully wet tower. This figure illustrates a single 'turbine response curve' which defines the rate at which heat is generated as a function of the temperature of the steam leaving the turbine. The heat rejection rate for the tower is represented by a family of 'tower' response curves corresponding to different wet-bulb temperatures. For a fixed wet-bulb temperature, thermal equilibrium is established at that point where the turbine

FIGURE 3.1 MATCHING OF TURBINE AND COOLING SYSTEM HEAT REJECTION

response curve and the appropriate tower response curve intersect. The plant operating temperature at that point is called the 'match-point' temperature.

Every cooling system model used for this thesis performs three tasks. The first is to derive, through thermodynamic models, the family of cooling system response curves for different meteorological conditions, while the second task is to determine, for a given plant design, the match-point temperature under each meteorologic condition. The third task is to measure the overall plant performance at these match-point temperatures. Penalties are incurred at higher temperatures, and are due to reduced plant operating efficiencies, higher energy costs required to maintain the plant at the higher temperature, or both. In addition, the cooling system consumes power in its operation and the cost of this auxiliary power is included with the penalty costs. Finally, a certain amount of water may be lost through evaporation and this water loss is assessed as well.

3.3 COOLING PONDS

As described earlier, cooling ponds are large water bodies that reject heat to the atmosphere through the combined effects of evaporation, radiation and conduction. Cooling ponds are typically shallow, on the order of ten to twenty feet in depth, and contain internal baffles to effect a one-dimensional flow (Figure 3.2). Cooling ponds are distinguished from other closed-cycle cooling systems by their

Figure 3.2 Plan View of a Typical Cooling Pond (Dresden, Illinois, Cooling Pond)

large thermal inertia with respect to changes in ambient meteorologic conditions. This feature is desirable from an operational point of view as this inertia tends to damp-out extremes in cooling system performance (and, hence, plant efficiency) induced by changes in the operating environment. However, this feature introduces some difficulties from a modelling standpoint insofar as the most accurate simulation of the performance of a cooling pond throughout a year must be done through a transient numerical simulation model using long series of meteorologic data. In this study we use a quasi-steady state approach developed at M.I.T. (Adams and Koussis, 1980; Jirka and Watanabe, 1978) which approximates the transient numerical model. This approach was applied in a comparative study of cooling systems for steam electric power plants by Najjar, et al., (1979). Whereas the numerical model keeps a record of the pond's delayed response to instantaneous changes in the environment, the quasi-steady state model assumes the pond immediately reaches steady state to meteorologic events that have been 'filtered' through some averaging process. By averaging the meteorologic data beforehand the quasi-steady state model simulates the thermal inertia one would observe in an actual pond. This model has been shown to give results that are quite close to the more time consuming transient numerical model when the length of the averaging period is equal to the pond's 'response time' (see below). This thesis uses the quasi-steady state model in all cooling pond simulations.

3.3.1 THE MIT QUASI-STEADY STATE COOLING POND MODEL

The governing equation for the quasi-steady state model is a vertically mixed, one-dimensional dispersive flux equation of the form:

$$u \frac{\partial T}{\partial x} = E_L \frac{\partial^2 T}{\partial x^2} - \frac{K}{\rho c H} [T - T_E] \quad (3.1)$$

where:

u pond flow-thru velocity (ft/day)

T pond temperature (F)

x distance along pond main axis (ft)

E_L turbulent dispersion coefficient

K surface heat transfer coefficient (BTU/ft /day)

ρc volumetric heat capacity of water (BTU/ft / F)

H pond depth (ft)

T_E Atmospheric equilibrium temperature (F)

The boundary conditions are given by:

at the inflow ($x=0$):

$$T_{x=0} - \frac{E_L}{u} \frac{\partial T}{\partial x} = T_0 \quad (3.2)$$

and at the outflow (x=L):

$$\frac{E_L}{u} \frac{\partial T}{\partial x} = 0 \quad (3.3)$$

where:

L is the overall pond length (ft).

T_0 is the temperature of the water entering the pond (°F)

$T_{x=0}$ is the temperature of the pond at the inlet (°F)

Equation (3.2) defines the dispersive mixing conditions at the entrance of the pond while Equation (3.3) removes any further dispersive flux at the pond outflow.

The dispersion coefficient comes from Fisher (1967) as applied by Jirka and Watanabe (1978) and is calculated from the following expression:

$$E_L = \frac{0.3 \sqrt{f/8} u [W/2]^2}{\kappa^2 H} \quad (3.4)$$

where:

κ von Karman's constant (0.4)

f bottom friction factor

W pond width (ft)

The pond 'response time' mentioned earlier is defined by the ratio $\rho c H / K$. For typical values of H (10-20 ft), K (100-300 BTU/ft²-°F-day) and $\rho c = 62$ BTU/ft²-°F this response time ranges between 2 and 12 days.

The solution to Equations (3.1)-(3.3) comes from Wehner and Wilhelm (1956) and may be written as:

$$\frac{T_i - T_E}{T_o - T_E} = \frac{4a \exp\left[\frac{1}{2E_L^*}\right]}{(1+a)^2 \exp\left[\frac{a}{2E_L^*}\right] - (1-a)^2 \exp\left[\frac{-a}{2E_L^*}\right]} \quad (3.5)$$

where:

$$a = \sqrt{1 + 4rE_L^*}$$

$$r = K \cdot A / \rho c$$

$$E_L^* = E_L / u \cdot L$$

T_o = temperature of the water entering the pond from the condenser (°F)

T_i = the temperature of the water returning to the condenser (°F)

A = pond area (ft²)

T_E , the water temperature at which there is no further heat flux across the pond surface, and K, the surface heat transfer coefficient, are calculated from meteorologic data using equations developed by Ryan and Harleman (1973). The interested reader may also refer to Najjar, et

al., (1979) for a derivation of these formulas.

3.3.2 MAKE-UP WATER REQUIREMENTS

The cooling pond water demand, also referred throughout this thesis as the make-up water demand, is used to replenish losses through seepage, blowdown, and the pond surface evaporation. This latter component is comprised of two terms: evaporation due to the pond's heat rejection ('forced' evaporation) and evaporation which would normally occur were the pond not heated ('natural' evaporation).

The make-up water demand for a cooling pond may be calculated through a water balance equation of the form:

$$Q_M = Q_{EF} + Q_{EN} + Q_B + Q_S + Q_P \quad (3.6)$$

where:

Q_M make-up flow (cfs)

Q_{EF} forced evaporation rate associated with the pond heat rejection (cfs)

Q_{EN} natural evaporation rate from the pond surface (cfs)

Q_B blowdown to prevent salt buildup in the cooling system circulating water (cfs)

Q_S seepage from the pond bottom (cfs)

Q_p precipitation (cfs)

In this thesis the combined natural and forced evaporation terms are calculated using an evaporative heat flux equation developed by Ryan and Harleman (op cit.). Their formulation assumes that partially saturated air at the pond surface is drawn away by two mechanisms: forced convection, which is proportional to the wind speed, and free convection, which is caused by the density difference between the moist air at the pond surface and the ambient air. The buoyancy term is proportional to the difference in the virtual temperatures (a measure of temperature which accounts for the partial saturation of air) between the two layers. The Ryan and Harleman equation is of the form:

$$Q_{EF} + Q_{EN} = \frac{A[22.4 \Delta\theta^{.333} + 14w][e_s - e_a]}{\rho \cdot 1030 \cdot 24 \cdot 3600} \quad (3.7)$$

where:

$\Delta\theta$ the average virtual temperature difference between the pond surface and the ambient air (°F)

w wind speed at 2 meters above the pond surface (mph)

e_s saturated vapor pressure at the average pond surface temperature (mm Hg)

e_a vapor pressure at the ambient air temperature 2 meters above the pond surface (mm Hg)

In this thesis we will assume the pond is lined and thus the seepage term in Equation (3.7) drops out. The precipitation term is taken from a climatologic atlas. The blowdown term is calculated on the basis of the maximum allowable concentration of dissolved solids in the condenser and piping. If we let C_M denote the concentration of salts in the make-up water and C_B denote the maximum allowable concentration of salts in the circulating equipment, then the blowdown flow is given by:

$$Q_B = \frac{Q_M \cdot C_M}{C_B} \quad (3.8)$$

From Equations (3.8) and (3.6) we may express the make-up water demand as:

$$Q_M = \frac{C_B}{C_B - C_M} [Q_{EF} + Q_{EN} + Q_P] \quad (3.9)$$

3.3.3 DESIGN PARAMETERS

Earlier work by Najjar, et al., (1979) and Adams, et al. (1979) illustrated the dependence of cooling pond performance on the area, the temperature drop across the pond, and the length to width (aspect) ratio. For a fixed pond width the aspect ratio is simply proportional to the surface area and need not be treated separately. Najjar (op cit.) demonstrated that a temperature drop across the pond of 20°F is optimal or near optimal for a range of capital and variable operating costs; this thesis will adopt this value as well. The remaining design

variable is the pond area, and for this thesis two areas will be evaluated: a 475 acre and an 800 acre pond. These span the range of pond areas found to be economic for an 800 MWe coal fired steam electric power plant (Najjar, et al., 1979). The ponds are U-shaped with an internal baffle running 70% of the pond length and with each of the two pond channels 2000 feet in width (Figure 3.3).

We note that the pond depth may also be treated as a design variable, particularly in the case where the plant designers wish to exploit the storage capabilities of the pond. Another advantage for building a pond to deeper depths is that the day-to-day performance of the pond may be significantly enhanced. Beyond pond depths of 9 feet, however, this improved performance translates into only marginal increases in the net power produced by a base-load turbine.

In this thesis ponds will be 9 feet deep unless the need for storage dictates a deeper pond should be built.

Table 3.1 lists the principal cooling pond design parameters used in this thesis.

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3.3.4 COOLING POND COSTS

The principal costs of a cooling pond are for land, grading and contouring, excavation and diking, and lining. A liner may be required if designers wish to keep seepage within specified limits. Figure 3.4 illustrates the relative cross-sectional dimensions of the pond dikes used here. The costs of land and grading are assumed to be \$2000/acre. The costs of diking, excavating, and lining have a substantial impact on the cost of a cooling pond. Indeed, these costs are significant for off-stream reservoirs used to supply make-up water for other cooling systems as well. These costs will be examined under three reservoir cost scenarios later in this thesis. The three scenarios are: (1) lining = \$0, diking and excavation = $\$0.13/\text{ft}^3$; (2) lining = $\$0.3/\text{ft}^2$, diking and excavation = $\$0.2/\text{ft}^3$; (3) lining = $\$0.6/\text{ft}^2$, diking and excavation = $\$0.2/\text{ft}^3$. The diking and excavation costs are representative of costs found in the literature while the lining costs of $\$0.3/\text{ft}^2$ and $\$0.6/\text{ft}^2$ are representative of the costs of clay liners (Kays, 1977; MacDonald and Kline, 1979). Additional capital costs include pump, piping and condenser costs. A breakdown of the principal cost components for the cooling ponds is offered in Table 3.2.

FIGURE 3.4 CROSS SECTION GEOMETRY OF THE DIKES AND BAFFLES
USED IN THE COOLING PONDS AND STORAGE RESERVOIRS

3.4 WET COOLING TOWERS

3.4.1 THE MERKEL EQUATIONS

The fully wet cooling tower is a large heat exchanger wherein water from the condenser is sprayed over an internal array of baffles where heat is lost to the circulating ambient air. The cooled water collects in a basin at the bottom of the tower and is returned to the plant. The wet tower examined in this thesis is an induced mechanical-draft design. This configuration draws outside air in and up through the tower by large fans located on the top of the tower.

The fundamental cooling tower heat transfer equations used today were first proposed by Merkel (1925). Merkel postulated a heat transfer mechanism whereby a thin layer of saturated air lies next to the circulating water and acts as an intermediary heat carrier between the water and the air. Merkel made the assumption that this saturated layer of air has the same temperature as the bulk water and postulated that the overall heat flux to the circulating air is driven by the difference between the enthalpy of the saturated air at the bulk water temperature and the enthalpy of the unsaturated air at the bulk air temperature. Under Merkel's hypothesis the relevant meteorologic condition governing the rate of heat transfer is the wet-bulb temperature.

The Merkel equations for the heat flux from the water to the air

within a crossflow tower takes the form (from Baker and Shryock, 1961):

$$-L \cdot \rho c \cdot dT = G \cdot dh = K_a \cdot V [h' - h] \quad (3.10)$$

where:

L = tower water flow rate (lb/hr)

ρc = heat capacity of water (btu/lb/°F)

T = water temperature (°F)

K_a = mass heat transfer coefficient (lb/ft³/hr)

h' = enthalpy of saturated air at the ambient water temperature (btu/lb dry air)

h = enthalpy of air at the bulk air temperature (btu/lb)

G = tower air flow rate (lb/hr)

V = effective heat exchange volume of the tower (ft³)

The first two terms in equation (3.10) equate the heat lost from the circulating water to the heat gained by the air. The third term represents the heat flux to the air as a linear function of the enthalpy difference between the air and the water streams. Equation (3.10) may be written as separate water-side and air-side heat exchange components and then integrated to give:

$$-\int_{T_1}^{T_2} \frac{dT}{(h'-h)} = \frac{Ka \cdot V}{L \cdot \rho c} \quad (3.11)$$

$$\int_{H_1}^{H_2} \frac{dh}{(h'-h)} = \frac{Ka \cdot V}{G} \quad (3.12)$$

where:

T_2 = temperature of the water leaving the tower (°F)

T_1 = temperature of the water entering the tower (°F)

H_2 = enthalpy of the air leaving the tower (btu/lb dry air)

H_1 = enthalpy of the air entering the tower (btu/lb dry air)

The coupled system of equations, (3.11) and (3.12), are solved with numerical models using T_1 , the temperature of the water entering the tower from the condenser, and H_1 , the enthalpy of the ambient air, for the water-side and the air-side boundary conditions, respectively. This thesis uses the finite difference cross-flow cooling tower model developed by Croley, et al. (1975), hereafter referred to as the 'Iowa model'. In the cross-flow tower the two fluid streams pass at right angles to each other, with the water cascading down through the fill and the air drawn horizontally across the fill (Figure 3.5).

The finite difference approximation for Equation (3.1) for a fill element x units wide, Δy units high and Z feet long is:

$$-L \cdot \rho c \frac{\Delta x \cdot \Delta T}{W} = G \frac{\Delta y \cdot \Delta h}{H} = Ka \Delta x \Delta y \overline{(h'-h)} Z \quad (3.13)$$

where ΔT is the water temperature drop across the increment, Δh is the air enthalpy rise across the increment, and W , H , and Z are, respectively, the width, height, and length of the tower. The term $(h'-h)$ is the average enthalpy difference within the increment and is approximated by:

$$\overline{(h'-h)} = 0.5[h'_i + h'_o - h_i - h_o] \quad (3.14)$$

where h'_i and h'_o are the inlet and exit enthalpies of the saturated air at the bulk water temperature, and h_i and h_o are the inlet and exit enthalpies of the air at the bulk air temperature. We can arbitrarily specify an equal number of vertical and horizontal elements throughout the tower:

$$N = \frac{W}{\Delta x} = \frac{H}{\Delta y} \quad (3.15)$$

Finally, we make the following approximations:

$$\Delta T = t_i - t_o \quad (3.16)$$

$$\Delta h' = h'_i - h'_o \quad (3.17)$$

$$\Delta h = h_o - h_i \quad (3.18)$$

FIGURE 3.5 SCHEMATIZATION OF INCREMENTAL VOLUMES WITHIN THE WET TOWER FILL

where:

t_i = the temperature of the water entering the element

t_o = the temperature of the water leaving the element

and rewrite Equation (3.13):

$$G[h_o - h_i] = \frac{Ka \cdot V}{2N} [h'_i - h_i + h'_o - h_o] \quad (3.19)$$

$$G[h_o - h_i] = L \cdot \rho c [t_i - t_o] \quad (3.20)$$

where $t_i = T_1$ for water entering the tower (the top-most fill elements)

and $t_o = T_2$ for water leaving the tower.

3.4.2 MAKEUP WATER REQUIREMENTS

As with the cooling pond, the tower make-up water demand is equal to the sum of water lost through evaporation plus water lost through blowdown. That is:

$$Q_M = Q_B + Q_{EF} \quad (3.21)$$

or, using Equation (3.8):

$$Q_M = Q_{EF} \frac{C_B}{C_B - C_M} \quad (3.22)$$

In calculating the evaporative water loss we assume the air leaving the tower is saturated. In this manner the evaporative loss is given by:

$$Q_{EF} = \frac{[w_o - w_i] \cdot G}{\rho c \cdot 3600} \quad (3.23)$$

where:

w_o = absolute humidity of the saturated air leaving the tower

w_i = absolute humidity of the ambient air

and

$$w_i = \frac{.622 \cdot P_i}{P_{atm} - P_i} \quad (3.25)$$

$$w_o = \frac{.622 \cdot P_s [T_{wbe}]}{P_{atm} - P_s [T_{wbe}]} \quad (3.26)$$

where:

P_{atm} = atmospheric pressure (psi)

P_i = vapor pressure of the ambient air (psi)

P_s = saturated vapor pressure of the air at the exit wet bulb temperature T_{wbe} (psi)

3.4.3 DESIGN VARIABLES

Earlier work by Najjar, et al. (1979) suggests that a 500 foot long wet tower is a good selection for the coal-fired electric plant under a fairly broad range of economic conditions. The tower fill height and fill width is 60 feet and 36 feet, respectively. The unit plan area water loading rate is 6500 lb/hr/ft^2 and the air loading rate on each side of the tower is 1800 lb/hr/ft^2 . The fan power requirements are calculated from air head loss data which is considered proprietary. The calculated value of the head loss itself, however, is roughly 75 feet. Table 3.3 presents a summary of the major tower design parameters used in this thesis.

3.4.4 COOLING TOWER CAPITAL COSTS

The capital cost of a cooling tower is based on the concept of a 'tower unit', which is a measure of the tower's performance at a specified wet-bulb temperature. The tower unit is the product of two terms: the plan area water loading across the tower (in gpm) and a 'rating factor'. The rating factor is directly related to the heat transfer term used in Equation (3.19) and therefore reflects the intrinsic operational efficiency of the tower. Rating factor curves for

**TABLE 3.3   PRINCIPAL DESIGN PARAMETERS FOR THE 500 FOOT
WET COOLING TOWER**

Tower Length:	500 feet
Tower Width:	36 feet
Fill Height:	60 feet
Unit Plan Water Loading:	6500 lb/hr/ft²
Unit Air Loading per Side:	1800 lb/hr/ft²
Fan Head Loss:	75 feet
Temperature Drop Across The Tower:	31 F°

specific wet-bulb temperatures may be found in papers by Dickey (1979) and Dickey and Cates (1973). Figure 3.6 illustrates the relationship between the rating factor, the equilibrium heat rejection from the wet tower and the net plant power output (after subtracting out the tower power consumption) at a wet-bulb temperature of 76 °F. The value of the heat transfer coefficient in Equation (3.19) is approximately 3.6 and thus the rating factor for the wet tower is estimated to be equal to 2.1. The cost per tower unit is estimated at \$14.50. This is based on the average of thirty-nine project records compiled by Dickey (1979). This unit cost accounts for the cost of the tower structure plus motors, fans, wiring, controls, and installing a concrete water collection basin. Table 3.4 presents a breakdown of the capital costs used for the 500 foot tower configuration examined in this thesis.

3.5 DRY-WET COOLING TOWER

The dry-wet cooling tower is a design using both dry towers and wet towers. A number of tower configurations have been proposed and evaluated (Croley, et al., 1975; Hu and Engleson, 1977; Choi and Glicksman, 1979) with the general conclusion that the optimal configuration is a series path arrangement (Figure 3.7). Water from the condenser first passes through the dry towers after which some fraction of the flow is sent to the wet towers and the remainder is sent directly to the condenser. The modular design of the wet towers allows the plant operators to vary the amount of water passed through the wet towers and thereby control, to a rough degree, the plant thermal

FIGURE 3.6 RELATION BETWEEN THE RATING FACTOR AND THE HEAT REJECTION FROM A WET COOLING TOWER

TABLE 3.4   PRINCIPAL COST COMPONENTS FOR THE 500 FOOT
WET COOLING TOWER [\$ Millions]

Pumps and Piping:	5.8
Condenser:	3.4
Wet Tower:	7.1
Replacement Capacity:	.4

FIGURE 3.7 WATER FLOW DIAGRAM FOR THE TWO DRY-WET COOLING TOWERS

operating efficiency and the water consumption rate during any period. This controllability feature is important from the standpoint of allowing the plant operators some latitude in operating the plant within water supply limitations. We will return to this aspect later in this chapter and expand upon it in subsequent chapters.

3.5.1 PERFORMANCE MODEL

The only new feature that differs from the all wet towers is the presence of the dry tower sections. From Choi and Glicksman (1979) the dry tower performance is given by:

$$\dot{Q}_D = \rho c \cdot C \cdot Q [T_o - T_{db}] \quad (3.27)$$

where $\dot{Q}_D$ equals the tower heat rejection (btu/hr); C equals a transfer coefficient; Q equals the dry tower water loading (lb/hr); T_o equals the tower inlet temperature; and T_{db} equals the ambient dry bulb temperature. The term $T - T_{db}$ is referred to in the literature as the 'initial temperature difference' (ITD). The heat transfer coefficient is a characteristic of the dry tower design and is a function of the effective air loading on the dry tower heat exchange tubes, or bundles, the effective surface area available for heat transfer and the heat transfer coefficients on both the water-side and the air-side of the heat exchange bundles. These points are discussed in greater detail by Choi and Glicksman (1979).

Referring to Figure 3.7, the complete heat transfer model for the dry-wet cooling tower may now be described as follows: The direct condenser flow (stream 1) passes through the dry towers where it loses heat in accordance with the heat transfer equation (3.19). The wet tower bypass (stream 2) loses additional heat in accordance with the coupled equations (3.11) and (3.12), where T_1 , the temperature of the water entering the wet tower, is the temperature of the water leaving the dry tower. The alternate bypass (stream 3) loses no additional heat. The total heat rejection from the dry-wet tower is then:

$$\dot{Q}_{\text{TOTAL}} = \dot{Q}_D + N \cdot \dot{Q}_{\text{WT}} \quad (3.28)$$

where N is the number of wet tower modules in operation at any one time and $\dot{Q}_{\text{WT}}$ is the heat rejection per wet tower module (btu/hr).

3.5.2 WATER REQUIREMENTS

The make-up water demand for a dry-wet tower is due wholly to the evaporative losses from the wet tower and at any time is given by:

$$Q_M = N \cdot q_M \quad (3.29)$$

where q_M equals the make-up demand per wet tower module and is derived

from equations (3.22)-(3.26).

3.5.3 DESIGN VARIABLES

Two dry-wet tower designs are examined in this thesis. These configurations are distinguished from one another by the percentage of the total heat rejection load handled by the dry tower sections during a specified design dry bulb-wet bulb condition. The desired split in the total heat load between the dry and wet towers is accomplished by varying the ratio of dry tower modules to wet tower modules installed at the plant (assuming all tower modules are operated during the specified condition). A higher ratio of dry modules to wet modules allows the plant to operate at a desired efficiency during a given dry bulb-wet bulb event with a lower water consumption rate. This reduced need for water, however, is offset by the higher capital and operating costs of dry towers relative to wet towers.

From here on in this thesis we will refer to the two dry-wet tower designs as 30%, and 40% dry designs. The percentages correspond to the relative heat load handled by the dry towers with both towers in full operation at a design dry bulb temperature of 100°F and a wet bulb temperature of 80°F. Both the dry and the wet tower sections operate as a collection of discrete, independently controllable modules, meaning the plant operator can, within thermodynamic limitations imposed by the plant and the ambient meteorology, adjust the amount of heat rejected by the wet tower modules (and thus adjust the evaporative loss rate) at any

time. Section 3.7 will discuss in greater detail the advantages of controlling the operational state of the dry-wet tower cooling system.

Table 3.5 summarizes the principal design features of the two dry-wet tower configurations.

3.5.4 DRY-WET COOLING TOWER COSTS

The wet tower sections are priced by the same procedure described earlier for the all wet tower and will not be repeated here. As with the wet tower, the principal costs for the dry tower are the heat exchanger, the fans and pumps, the foundation and the electrical equipment. Currently, dry towers continue to be more or less custom designed for the specific application needed, and standardized cost procedures are not available. The estimated costs for the dry tower sections are taken from Choi and Glicksman (1979) and the reader is referred to this study for a complete breakdown of the component costs.

Table 3.6 presents the cost parameters assumed for the two dry-wet tower designs. An important observation is that the capital cost of the dry-wet tower is several times greater than the capital costs of either the fully wet tower or cooling pond.

TABLE 3.5   PRINCIPAL DESIGN PARAMETERS FOR THE 30% AND
THE 40% DRY-WET COOLING TOWERS

	30% Dry	40% Dry
Dry Tower:		
Water Flow Rate (lb/hr):	1.2×10^8	1.8×10^8
Heat Transfer Coefficient ('C'):	.32	.32
Fan and Pump Power Loss (MWe):	6.1	9.1
Wet Tower:		
Maximum Water Flow Rate (lb/hr):	$.8 \times 10^8$	$.7 \times 10^8$
Heat Transfer Coefficient (KaV/N):	2.1	2.1
Fan and Pump Power Loss (MWe):	3.7	3.2
Design Dry Bulb (°F):	100.0	100.0
Design Wet Bulb (°F):	80.0	80.0
Heat Load Split at Design (Dry/Wet):	30%/40%	40%/60%

TABLE 3.6 PRINCIPAL COST COMPONENTS FOR THE 30% AND THE 40% DRY-WET COOLING TOWERS [\$ Millions]

	30% Dry	40% Dry
Pumps and Piping:	14.4	14.8
Condenser:	4.1	5.1
Dry Tower:		
Heat Exchanger:	8.7	15.3
Tower Structure:	1.8	1.8
Fan and Electrical Equipment:	4.5	4.5
Louvre:	1.4	1.4
Wet Tower:	4.9	4.3
Replacement Capacity:	1.6	1.1

3.6 DRY TOWER-COOLING PONDS

The dry tower-cooling pond system is similar to the dry-wet tower configuration with the exception that the wet cooling tower is replaced by a cooling pond. Figure 3.8 illustrates one possible arrangement for this design. Our initial studies of dry tower-cooling pond designs indicate that both parallel and series routing of flows through the two components are efficient from Fall to early Spring when conditions for cooling are favorable, but only the series routing should be used during the late Spring and Summer when the maximum possible cooling is required. As with the dry-wet cooling tower, one advantage of a dry tower-cooling pond configuration is a reduction in water consumption. In addition, the pond can serve as its own make-up water reservoir, an advantage in dry areas where even dry-wet towers may require reservoir storage during times of drought.

The various operating modes for the dry tower-cooling pond are realized by regulating the distribution of the condenser flow through the pond and dry tower. While natural evaporation from the pond surface will always lead to some background water loss, the plant operator may adjust the rate of forced evaporation by selecting different flow rates through the pond. As with the dry-wet cooling towers, reduced water consumption rates come at the expense of reduced plant operating efficiencies. Whereas the dry tower responds almost immediately to changes in ambient dry bulb temperatures, the pond's response time may be on the order of 1 to 12 days, the rate being proportional to the current pond depth and inversely proportional to the value of the heat

FIGURE 3.8 WATER FLOW DIAGRAM FOR THE DRY TOWER-COOLING POND

transfer coefficient across the pond surface. Consequently, the performance of a particular operating mode during any one day will depend on the mode of operation followed during preceding days, and will in turn go on to affect performance on following days. In this thesis we will assume the dry tower-cooling pond configurations operate under a single mode for a month at a time. That is, if the heat load from the plant condenser is split 20%-80% between the pond and the dry tower at the beginning of the month it will continue to be this way for the remainder of the month. This is long enough for the system to approximate steady state behavior and thereby removes the potentially large computational burden of dealing with transient cooling behavior.

The performance models used to simulate the operation of the dry tower and the cooling pond were presented in sections 3.5 and 3.3, respectively, and will not be repeated here. The only important modification is the routing of the condenser flow between the two heat exchangers may be parallel or series. The hot water entering the pond is at the dry tower outlet temperature when the system operates in serial-flow mode.

3.6.1 MAKE-UP WATER REQUIREMENTS

The make-up water requirements are due wholly to the presence of the cooling pond. The relevant water balance equations, (3.6)-(3.9), were presented earlier and will not be repeated here.

3.6.2 DESIGN VARIABLES

A single dry tower-cooling pond design is examined in this thesis. The relative share of the total heat load handled by the dry tower at a design dry-bulb temperature of 83°F and a design equilibrium temperature of 96°F is roughly 50%. This is with both systems at full operation in a series flow configuration. Table 3.7 lists the design parameters associated with this configuration.

3.6.3 CAPITAL COSTS

The various components contributing to the capital costs of cooling ponds and dry towers have been reviewed earlier and will not be repeated here. Table 3.8 summarizes the costs for the principal components for this system.

3.7 SIMULATION RESULTS

This section presents the results from the cooling system simulation models for the six cooling system designs reviewed in the last five sections. To recapitulate, these systems are a 475 acre cooling pond, an 800 acre cooling pond, a 500 foot long wet cooling tower, a 30% and a 40% dry-wet cooling tower, and a 50% dry tower-cooling pond. These simulations are carried out for an 800-MWe coal-fired steam electric plant. These results, in effect, represent an energy firm's production function with respect to water. Insofar as the water consumption rates

TABLE 3.7   PRINCIPAL DESIGN PARAMETERS FOR THE 50% DRY
TOWER-50% COOLING POND

Dry Tower:

Water Flow Rate (lb/hr):	1.8×10^8
Heat Exchange Coefficient ('C'):	.32
Fan and Pump Power Loss (MWe):	9.1

Cooling Pond:

Surface Area (acres):	275.0
Maximum Water Flow Rate (lb/hr):	1.2×10^8
Power Loss (MWe):	-
'Standard' Design Depth:	10.0 feet
Minimum Operating Depth:	5.0 feet
Design Dry Bulb (°F):	83.0
Design Equilibrium Temperature (°F):	96.0
Heat Load Split at Design (Dry/Pond):	50%/50%

TABLE 3.8   PRINCIPAL COST COMPONENTS FOR THE 50% DRY
TOWER-50% COOLING POND [\$ Millions]

Pumps and Piping:	14.7
Condenser:	5.1
Dry Tower:	
Heat Exchanger	8.7
Tower Structure:	1.8
Fan and Electrical Equipment:	4.5
Louvre:	1.4
Cooling Pond: [See Chapter 5]	
Replacement Capacity:	2.2

for cooling ponds and fully wet towers cannot be controlled by a plant operator, the simulation results define monthly water consumption rates for these two systems. The water consumption rates for the hybrid dry-wet cooling systems can be controlled by the plant operator and the simulation results are used to develop, for every month, the complete (non-linear) functions relating power production to water consumption. Chapter 4 will describe how these functions can be incorporated within models used to select optimal operating policies for each hybrid design.

The meteorologic data used for these simulation comes from Moline, Illinois. While Moline is not adjacent to the western coal fields themselves, its meteorology is representative of the average meteorologic conditions found in the western coal-bearing states.

The turbine generator selected for the plant is a conventional General Electric turbine with a maximum allowable back-pressure of 5 inches HgA. The turbine produces 810 MWe at a 3.5 inch backpressure and the total thermal heat input to the plant is 7.06 billion btu/hr.

The plant must meet a nominal demand of 800 MWe. When the net plant output exceeds the demand the turbine is throttled back to the point where demand is just met. When the net power output cannot meet the nominal demand a gas turbine is used to cover the difference. The required gas turbine replacement capacity for each cooling system is calculated as well.

While the performance characteristics of the six cooling systems are

with respect to a fixed turbine capacity, we note that an alternative approach would be to use a 'scalable' turbine capacity instead. With this approach the capacity of the turbine is scaled with respect to both the plant demand and the unique performance behavior of each cooling system in order to achieve the best tradeoff between the use of baseload plant capacity (high capital cost but low operating cost per unit) and replacement capacity (low capital cost but high operating cost per unit) in meeting the plant demand.

Table 3.9 lists a number of important operating statistics for the cooling systems examined: annual boiler fuel consumption; annual makeup water consumption; annual replacement energy consumption; and the backup turbine capacity required to meet the maximum observed power deficit. Two entries appear for each of the hybrid dry-wet cooling systems. The first corresponds to an operating policy which minimizes water consumption without causing the turbine backpressure to exceed a maximum of 5 inches Hga. While the second corresponds to an operating policy which maximizes net plant power output.

Figures 3.9 - 3.11 illustrate the monthly net power output versus water consumption curves for the three dry/wet cooling systems. We note that these curves are concave for each system--additional water consumption brings diminishing increases in output--and relatively flat in the winter and late fall. This implies that optimal operating policies are going to have only a marginal effect for these months. During the spring and summer months, however, these curves have very sharp curvatures, leading us to conclude that the choice of the

TABLE 3.9 OPERATING STATISTICS FOR THE SIX COOLING SYSTEMS

COOLING SYSTEM	BOILER FUEL (MW _t)	BACK-UP ENERGY (MW _e)	EVAPORATION (cfs)	BACK-UP CAPACITY (MW _e)
475 ACRE COOLING POND	2048.5	1.2	12.1	6.6
800 ACRE COOLING POND	2042.5	.2	14.0	2.4
500 FOOT WET COOLING TOWER	2059.7	.7	11.1	2.7
40% DRY-60% WET TOWER:				
	2060.0	2.4	4.2	7.0
	2063.0	6.6	1.3	7.0
30% DRY-70% WET TOWER				
	2060.0	3.2	5.4	10.0
	2066.3	13.0	3.1	20.0
50% DRY-50% COOLING POND				
	2054.0	3.8	5.7	14.0
	2062.1	5.0	3.5	14.0

FIGURE 3.9 MONTHLY NET POWER OUTPUT VERSUS MAKE-UP WATER CONSUMPTION FOR THE 40% DRY-60% WET COOLING TOWER

FIGURE 3.10 MONTHLY NET POWER OUTPUT VERSUS MAKE-UP WATER CONSUMPTION FOR THE 30% DRY-70% WET COOLING TOWER

FIGURE 3.11 MONTHLY NET POWER OUTPUT VERSUS MAKE-UP WATER CONSUMPTION FOR THE 50% DRY-50% COOLING POND

operating policy will have a pronounced effect.

CHAPTER 4   RESERVOIR SIMULATION AND OPERATIONS ALGORITHMS

4.1   INTRODUCTION

This chapter introduces the reservoir simulation and dry-wet cooling operations algorithms used to evaluate the total costs of alternative cooling system designs and water use practices. This evaluation is made in light of a number of the water supply considerations discussed in Chapter 2. The algorithms presented here will be used for two purposes in this thesis. At the simplest level these algorithms are used to keep track of costs to insure that all cooling system alternatives can be compared with one another on a consistent 'total cost' basis. The total cost of a particular cooling system is the sum of both the capital and operating costs of the cooling system itself plus the costs of the 'infra-structure', such as reservoirs and water rights purchases, needed to secure a reliable supply of water for the plant. These algorithms serve a second purpose by allowing us an efficient means to examine the non-inferior set of 'infra-structure' alternatives for a given cooling system. For any cooling system there is a tradeoff between installing larger amounts of storage and, where possible, purchasing a larger number of existing water rights. In fact, the algorithms discussed here will allow us to differentiate water rights purchases from actual water rights use. A non-inferior point on the tradeoff between reservoir capacity and water rights purchases may be to purchase a block of rights even though the plant will actually use these rights only during rare drought events. Solutions of this sort will be discussed in Chapter 5 where we look at alternative arrangements for acquiring water rights. The reservoir simulation algorithm is used to

determine the feasible tradeoffs between installing larger or smaller reservoirs and making smaller or larger purchases of existing water rights for every cooling system design. The operations algorithm is used to determine optimal operating practices for cooling systems having controllable water consumption rates; in this case dry-wet towers and dry tower-cooling ponds.

The reservoir simulation model is the simpler of the two general algorithms described in this chapter and will be presented in the next section. The remaining sections in this chapter will present the operations algorithm and some variations on the model.

4.2 RESERVOIR SIMULATION/WATER RIGHTS ACQUISITION MODEL

The purpose of the simulation model is to determine how an energy facility's water demands may be met through water held in reservoir storage plus water acquired through purchases of existing water rights. Up to a limit, the plant can choose to install larger reservoir capacities to capture unappropriated water in the stream and thereby reduce the number of existing rights it needs to purchase. There is a critical reservoir surface area above which the combined water loss from the cooling system plus the evaporation from the pond surface will exceed the long-run water supply available to the plant at a desired level of reliability. This long-run condition is unavoidable and it may dictate that a minimum number of water rights must be owned by the plant before a particular cooling system will have its water demands met with the desired reliability.

The legal and institutional restriction on water transfers notwithstanding, the number of combinations of potential water rights purchases

available to a plant may be enormous. The large number of rights frequently outstanding on a river plus the various uses to which these are currently put in addition to their respective levels of seniority all contribute to the complexity of the purchase decision. The plant's location on a river will also add to the number of alternatives available, depending on the number of rights upstream and downstream of the plant site. In Figure 4.1 we find that Plant A can effectively make use only of those rights outstanding on its tributary; it will need to construct a pipeline before it can use water rights assigned to neighboring tributaries. Plant B can effectively make use of any rights assigned to the three tributaries above it in addition to water rights in use downstream of it. While Plant C appears to have the same options available to Plant B, it is located so far downstream there is the possibility that during extreme droughts most of its water would be lost through seepage or evaporation before reaching the plant. In water law this is known as making a 'futile call'. That is, the appropriator is located so far downstream that even if all junior appropriators above it were prevented from withdrawing water above the plant the instream losses would prevent a major portion of its allotment from reaching it. In such cases local water authorities will permit upstream junior users to divert this water in order that it may be applied to a beneficial use.

Table 4.1 lists a number of the features of western water rights that contribute to the complexity of the water purchase decision. Each of these features can drastically alter the amount of water actually available for consumption from a purchased right. As noted before the predominant water use in the West is for irrigation. Typically the amount of water actually consumed in irrigation is anywhere from 30% to 70% of the water actually

TABLE 4.1 FEATURES OF WESTERN WATER RIGHTS THAT
CONTRIBUTE TO THE WATER PURCHASE DECISION

<u>FEATURE</u>	<u>EFFECT</u>
Seniority of the right	Determines the reliability with which the rights will actually deliver water. This enters in the tradeoff between building reservoir storage and purchasing additional water rights.
Use of the water	In some cases water rights cannot be transferred from a more 'preferred' use to a less preferred one. In addition, during severe droughts water administrators may allow water to go to preferred uses at the expense of less preferred ones, even if the rights for the latter are senior to those of the former.
Location of the diversion point of the right relative to other users on the river	Determines the type of non-injury provisions that might be needed in order to transfer an existing water right to a new use and/or a new point of diversion on the river.
Historical consumptive use of a right	Sets the maximum amount of water that can be consumed when the right is transferred to a new use and/or a new diversion point.

FIGURE 4.1 ILLUSTRATING THE EFFECT OF PLANT LOCATION
AS A FACTOR IN SELECTING DIFFERENT WATER
ACQUISITION STRATEGIES (see text)

withdrawn from the river, and this then places an upper bound on the fraction of the purchased water right that can be consumed by an energy plant. The prohibition against transferring a water right in such a way that junior appropriators on the river are injured may reduce the amount of water available for consumption by a similar amount. A study by Gerstle and Marks (1979) on water right transfer options on the Powder River demonstrated that anywhere from 0% to 100% of a right could be legally transferred to a new point of diversion, depending on the seniority and location of the original right. In addition there are likely to be synergistic effects accompanying the transfer of two or more rights. Clearly some assumptions are needed if we are to examine the tradeoff between storage and rights purchases within a reasonable computational effort. As we shall see shortly the computational burden may still be enormous even after a number of simplifying assumptions have been adopted.

The first assumption is the plant will receive the full consumptive flow of a purchased right irrespective of the right's original diversion point on the river. In actual practice the location has an important effect and the consumptive flow available to the firm may be less than the amount historically consumed at the original diversion. This, of course, will inflate the amount of water actually available for consumption. Nevertheless we can partially compensate for this assumption later on in the analysis.

The second assumption is to assume all rights purchases are either the most senior rights or the most junior rights on the river. This assumption will give us an overall feeling for the tradeoffs available between storage and right seniorities without too much computational effort. The disadvantage is that we cannot examine the storage-water purchase tradeoffs

available by purchasing rights having different seniorities. This drawback could be circumvented somewhat by lumping water rights into broad seniority classes, but this approach will not be pursued here.

A third assumption is to assume the plant may purchase rights for different months. That is, there are separate rights for, say, May and June. The advantage in adopting this assumption is that it allows us to monitor the plant's water demands on a month to month basis. For example, the simulation model may determine that over a wide range of reservoir capacities the plant should always purchase some number of rights for October but can operate without making diversions from April to June. The shortcoming of this assumption is that markets may not exist in which monthly water rights may be purchased.

The fourth and final assumption is that all water in the river belongs to either one of two types: appropriated water, currently belonging to other users, and unappropriated, or surplus, water. Appropriated water may be further differentiated by use, or, as noted earlier, by seniority. For the time being appropriated water will be treated as if it has a single use. Surplus water is always junior to appropriated water. It may be further noted that special uses for water, such as instream flows, may either be subtracted from the total streamflow if they are nonnegotiable uses, or may be added to the appropriated water if they are negotiable ones.

For a fixed cooling system design (having a fixed schedule of monthly water demands) the first step in the simulation model is to determine the maximum and the minimum reservoir capacities the plant might need to build. The maximum capacity corresponds to the scenario where the plant has acce

to only surplus water while the minimum capacity corresponds to the scenario where the plant owns all the rights outstanding on the river. These bounds are solved using a sequent-peak algorithm of the form:

$$v_k = \max \begin{cases} d_k + r_k + e_k(V) - i_k \\ v_{k-1} \end{cases} \quad 1 \leq k \leq N \quad (4.1)$$

$$d_k = \max \begin{cases} 0 \\ d_{k-1} + r_{k-1} + e_{k-1}(V) - i_{k-1} \end{cases} \quad 1 \leq k \leq N \quad (4.2)$$

$$V = v_N \quad (4.3)$$

where,

v_k is the maximum accumulated storage deficit at period 'k'

d_k is the net accumulated storage deficit at period 'k'

r_k is the make-up water consumption in period 'k'

i_k is the water available to the plant in period 'k' under either of the two water availability scenarios

e_k is the unit surface evaporation rate in period 'k'

V is the reservoir volume

Equations (4.1)-(4.3) must be solved in an iterative manner due to the presence of the reservoir evaporation terms in Equations (4.1) and (4.2).

These surface evaporation terms are proportional to the reservoir surface area, and for a fixed pond depth are proportional to the pond volume as well. The iterations will converge unless the pond area becomes so large that the combined water demand from the cooling system and from the surface evaporation exceeds the long-run average flow available to the plant. The solution will diverge in this case and the only remedy is to decrease the required surface area by increasing the depth.

Having determined upper and lower bounds on the reservoir capacities the next task is to determine the tradeoff between storage and water rights purchases for intermediate storage pond sizes. This is accomplished by selecting intermediate reservoir capacities and using a search algorithm to select the 'minimum cost' collection of water rights which, when combined with the given reservoir capacity, will meet the plant water demands over some extended period of simulated flows (say, 100 years). The term 'minimum cost' is applied loosely here for in fact the search algorithm used is not guaranteed to lead to an optimal solution, but only a good one. The number of purchase combinations becomes staggering even for small problems. Table 4.2 lists the estimated number of rights available during the irrigation season at a test site on the Middle Fork of Crazy Woman Creek in the Powder River Basin in Wyoming. The number of acres in irrigation is relatively small--2500 in total. If we assume rights may be purchased in units of 1 cfs then the number of combinations is 380 million! If rights are purchased in units of 3 cfs the problem reduces to 58,000 combinations--still an impressive problem.

In deriving the search algorithm we will begin by defining a few terms. Let:

$S\{p=p_1, p_2, \dots, p_{12}\}$ denote the set of current water rights held

$M(S\{p\})$ denote the minimum storage volume in the reservoir observed over a simulated period of operation given the plant holds the rights $S\{p\}$

$\frac{\partial M(S\{p\})}{\partial p_i}$ denote the partial derivative of $S\{p\}$ with respect to p_i

TABLE 4.2   ESTIMATED MONTHLY IRRIGATION DEMAND ON CRAZY
WOMAN CREEK

APPLICATION RATES (INCHES/MONTH)

APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER
2.2	4.8	3.8	4.8	4.6	3.2	.9

IRRIGATION DEMAND (CFS)

APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER
11.0	23.0	20.0	24.0	24.0	17.0	8.0

C_i denote the unit cost of right p_i pp

The minimum storage volume, $M(S\{p\})$ is determined by simulating the operation of the cooling system and the reservoir over a number of years. If the plant designers are interested in meeting a probability no greater than α that the reservoir will run dry then $M(S\{p\})$ can be readily redefined as the storage volume which is exceeded with a probability of $1-\alpha$. Clearly, this volume is a function of both the capacity of the reservoir and the seasonal cooling system water demands, but we shall consider these fixed for the moment. We shall assume the firm will prefer to hold just enough rights to bring this minimum storage level arbitrarily close to zero; otherwise it is holding onto too many rights.

Consider the set $S^*\{p\}$ for which $M(S^*\{p\})$ is positive and arbitrarily close to zero. Then:

$$\Delta P_i = \frac{-M(S^*\{p\})}{\frac{\partial M(S^*\{p\})}{\partial p_i}} \quad (4.4)$$

is the approximate change in p_i which will drive $M(S^*\{p\})$ to zero. For $S^*\{p\}$ to be an optimal set of rights held, the following marginal condition must hold:

$$C_i \Delta P_i = C_j \Delta P_j \quad \text{all } i, j \quad (4.5)$$

If Equation (4.5) were not met, that is, there exists two rights p_k and p_l for which $C_k p_k > C_l p_l$, then the plant could increase (by a marginal amount) its holding of p_k and decrease (by a marginal amount) its holding of p_l , and thus achieve a zero minimum storage level at a reduced cost.

Suppose we have a current holding of rights, $S'\{p\}$, for which the minimum storage volume, $M(S'\{p\})$ is much larger than zero. Clearly we can reduce some of the rights currently held, but the question is which ones?

Let $m(S'\{p\})(p_i)$ represent the minimum simulated storage level if the current holding of right 'i' is reduced by one unit. To a first approximation then,

$$\frac{\partial M(S'\{p\})}{\partial p_i} \approx M(S'\{p\}) - m(S'\{p\})(p_i) \quad (4.6)$$

and then,

$$\Delta P_i \approx \frac{-M(S'\{p\})}{M(S'\{p\}) - m(S'\{p\})(p_i)} \quad (4.7)$$

Equation (4.7) is an extrapolated value of the reduction in the amount of right 'i' which will drive $M(S'\{p\})$ to zero. The search algorithm starts with an initial holding of water rights, evaluates Equations (4.6) and (4.7) for each month for which the plant continues to hold water rights, and selects the right, i , satisfying the equation,

$$P_i^* = \{P_i \mid \max \{c_1 \Delta p_1, \dots, c_{12} \Delta p_{12}\}\} \quad (4.8)$$

The right p_i^* is then decremented by 1 cfs. The algorithm repeats the process until it finds the set of rights $S^*\{p\}$ such that,

$$m(S^*\{p\})(p_i) = 0 \quad \text{all } i \quad (4.9)$$

This algorithm always strives for local optimality although there is no guarantee a priori that global optimality will be reached. Fortunately the

proposed algorithm may not be too far from optimal. A number of small-scale tests have been performed to compare the outcome from this algorithm with the true global optimum (determined by searching over all combinations of water rights purchases). In all the comparisons made to date the algorithm has led to optimal results.

Determining the frequency with which the plant actually uses the water rights it has purchased may be done in this model. For any month for which the plant holds rights to water the simulation algorithm calculates the minimum net inflow to the reservoir which will fill the reservoir to capacity. If the reservoir can be filled with surplus flows alone then clearly the plant has no use for additional water for that month. Similarly if the sum of surplus flows plus water right deliveries will not fill the reservoir then the entire allotment assigned under the rights for that month are needed.

4.3 THE OPTIMAL OPERATING POLICY ALGORITHMS

This section describes the models used to determine optimal operating policies for cooling systems having controllable water consumption rates. This is an important consideration for plant operators who, having some amount of reservoir capacity at their disposal, wish to know how they may best allocate water held in storage plus water from current river diversions for consumption in the cooling system. In addition, the optimal operating policy for a given cooling system design allows plant designers to compare alternative designs based on their expected optimal operating costs. Alternative formulations of the model are presented and evaluated with respect to both their computational features and their optimality (suboptimality) characteristics.

4.3.1 LINEAR PROGRAMMING

Linear programming was one of the first mathematical programming techniques to be used for the reservoir operating problem and offers the desirable feature that the operating problem can be readily solved with existing L-P algorithms without additional program development. Linear programming is an effective solution technique when the streamflows entering a reservoir are known with certainty. However it has limited usefulness vis a vis alternative solution techniques when streamflows are treated as random variables. For all practical purposes stochastic linear programming is limited to stationary Markov processes. To set up the problem for an L-P solution we must first select a particular cooling system design and must also specify the type of water rights possessed by the firm to characterize the effective streamflows available to the plant. In the LP formulation we think of the system as being in a given 'state' at any period, with the 'state' defined by two parameters: the current storage level in the reservoir and the streamflow observed in the prior period. For Markov processes the observation of a streamflow in the last period leads to a conditional probability distribution for the current period's streamflow. This in turn leads (through the continuity equation expressing next period's storage level in terms of this period's level, the incoming streamflow, and the target release) to a conditional pdf that the system will evolve to other states in the next period for every possible release decision made today. The L-P algorithm solves for the optimal conditional pdf that the system will move from one state in one period to other states in the next period, for all possible states and in all periods. The optimal release policy is then a function of the current state and the optimal conditional pdf for that state.

One advantage of using linear programming is the algorithm may be structured to solve the optimal reservoir capacity and the optimal operating policy for that reservoir within a few iterations. In addition the solution also generates the dual variables associated with the water supply constraints, and thus provides the analyst with an estimate for the marginal value of water to the energy facility in every period.

Unfortunately stochastic linear programming suffers two drawbacks. First it is limited to stationary Markov processes, and therefore cannot use real-time forecasting information for real-time reservoir control. This is actually a minor drawback at the design stage where realtime information, by definition, does not exist. The second drawback is the more severe of the two and it is that the size of the constraint set required to solve the problem may become quite large. While no attempt will be made here to draw specific conclusions on the size of the constraint sets for stochastic L-P problems of interest to us, we can examine the size required for one stochastic L-P reservoir control algorithm proposed by Houck and Cohon (1978). Their algorithm iterates between a policy model that determines the optimal operating policy for a fixed reservoir capacity, and a design model which converges on an optimal capacity. If we let:

- β equal the number of streamflow intervals per period
- γ equal the number of discrete storage intervals possible
in every period
- δ equal the number of periods in a year

Then the maximum number of constraints in the design model is:

$$[2\gamma^2\beta + \gamma + 1]\delta + 2 \quad (4.11)$$

and the maximum number of constraints in the policy model is:

$$[\gamma^2\beta + \gamma\beta + \gamma + 1]\delta + 2 \quad (4.12)$$

If we let $\beta = 5$ streamflow intervals, $\delta = 10$ storage intervals, and $\delta = 12$ months, then the design models will have approximately 12,100 constraints and the policy model will have approximately 12,700 constraints. As noted, these are upper bounds on the number of constraints that will be involved and the authors suggest the model size can frequently be reduced somewhat. Nevertheless by any measure this is a large problem and we have every reason to suspect the computational cost for purposes of design evaluation will quickly add up when many designs must be compared. For our purposes stochastic linear programming does not appear to be a logical choice for the operating policy algorithm.

4.3.2 DYNAMIC PROGRAMMING

Like stochastic linear programming, dynamic programming has been applied to numerous reservoir control problems. Its primary advantages are that it can handle a broader range of stochastic control problems than any other optimization technique, will solve non-stationary problems, and will generally not suffer from the same costs imposed by dimensionality problems that plague linear programming. The primary disadvantages to using dynamic programming are that most D-P algorithms must be written from scratch,

thereby involving costs incurred for program development and debugging. In addition, DP models solve only the operating problem--not the combined operations/design problem. Nevertheless, once a D-P algorithm has been written it may be used both to evaluate alternative designs, and as the real-time optimal controller for a design that has been built and is now operating. (This latter advantage is, for all practical purposes, not available with linear programming).

The stochastic D-P algorithm may be formulated in a number of different ways and it will be helpful to describe some of the alternatives and examine their various properties. We begin by defining a number of terms.

R_t Target cooling system evaporation loss in period t

i_t The 'effective' streamflow recieved by the plant in period t --i.e., the water available to the plant under its current holdings of water rights

S_t Storage level in the make-up water reservoir in period t

$g_t(.)$ Cost functional in period t

I_t 'Information vector' in period t . This is a collection of past streamflow observations, snowpack measurements, etc., that will be used to create a conditional pdf for future streamflows at the beginning of every period.

$E(.|I_t)$ Expectation operator given all the relevant information observed up to period t that can be used to create conditional pdf's on future streamflows.

The cost functional $g_t(.)$ measures penalty costs when the cooling system efficiency is reduced, thereby leading to lowered plant operating efficiencies. Recall from Chapter 3 that the cooling system efficiency is a function of the amount of water consumed in the cooling system, and it exhibits decreasing marginal returns to increases in cooling water consumption. Thus $g_t(.)$ is a convex function and is defined by:

$$g_t \min(R_t, S_t + i_t)$$

That is, the plant either consumes the target release, R_t , or the sum of water coming from storage plus current streamflows, whichever is smaller (negative storage volumes are not allowed).

We begin our examination of alternative formulations of the stochastic D-P algorithm by looking at the algorithm which theoretically leads to globally optimal solutions: the closed-loop optimal control.

I CLOSED-LOOP OPTIMAL CONTROL

The closed-loop optimal control solves the following set of recursive equations:

At some terminal period N

$$J_N[S_N, I_N] = \lambda_N [S_N, I_N] \quad (4.13)$$

At all other periods $0 \leq n < N$

$$J_n[S_n, I_n] = \min_{R_n} E_{i_n, I_{n+1}} \left[g_n \min[R_n, S_n + i_n] + J_{n+1}(S_{n+1}, I_{n+1}) \right] \quad (4.14)$$

Subject to the constraint

$$I_{n+1} = f_n(I_n, i_n) \quad 0 \leq n < N \quad (4.15)$$

$$S_{n+1} = \max(0, S_n + i_n - R_n) \quad 0 \leq n < N \quad (4.16)$$

The term $J_n[S_n, I_n]$ for $0 \leq n < N$ represents the optimal expected 'cost-to-go' from the state $[S_n, I_n]$ in period n (i.e. with $N-n$ periods left to go before the system stops). Thus Equation (4.13) states that the expected cost-to-go from a given state $[S_N, I_N]$ at the last period is equal to some assigned terminal condition (e.g. a salvage value). Equation (4.14) states that in any period n the optimal expected cost-to-go from the state $[S_n, I_n]$ is equal to the expected immediate cost of a target release plus the expected cost-to-go from ending up in any one of a possible number of states in the next period. Equation (4.15) states that the information vector for the next period, I_{n+1} , is a function of this period's information vector plus this period's streamflow, i_n . While i_n is not known at the beginning of period n , it is known at the beginning of the next period and thus contributes to the information available to the plant operator in the future. Equation (4.16) is the continuity equation for storage volumes from one period to the next.

Equations (4.13) thru (4.16) define the general structure for the closed-loop optimal control. It can handle stationary and non-stationary problems, as well as stochastic processes ranging from simple serially uncorrelated processes to high-order autoregressive ones. Even though the

analysis at the design stage must assume some stationarity, this algorithm may continue to serve as the real-time controller for an existing reservoir/cooling system combination.

For the design analysis problem we might assume a stationary system with the random streamflows represented by an ergodic Markov process. In this manner the information vector I_n is replaced by the observed streamflow in the prior period, i_{n-1} . In addition if we are looking at monthly or seasonal processes which repeat themselves from one year to the next then the stationary assumption allows us to re-write the cost functional:

$$g_n(.) = g_{n+T}(.) \quad (4.17)$$

Where T equals the number of periods in a year.

If the project lifetime is quite long ($N=\text{large}$) then we may rewrite the stochastic dynamic programming algorithm for a stationary ergodic Markov process in the following form:

$$J_n[S_n, i_{n-1}^\epsilon] = \min_{R_n} \sum_k \left[g_n \min(R_n, S_n + i_n^k) + J_{n+1}(S_{n+1}^k, i_n^k) \right] \cdot P_{\epsilon, k}^{n-1} \quad (4.18)$$

$$S_{n+1}^k = \min(0, S_n + i_n^k - R_n) \quad (4.19)$$

Where $P_{\epsilon, k}^{n-1}$ = the Markov transition probability of receiving the streamflow i_n^k given the streamflow i_{n-1}^ϵ was observed in the prior period. If $n-1=0$ then $i_{n-1} = i_{12}$; if $n+1=T+1$ then $S_{n+1} = S_1$ and $J_{n+1} = J_1$. The reader may notice that the terminal condition is absent in this formulation. This is due to the fact that for large values of N a completely ergodic Markov process is not affected by boundary conditions, and therefore the effect of the terminal condition eventually 'dies out' if we allow Equations (4.18)

and (4.19) to be solved in their recursive form for a number of yearly cycles. In addition the algorithm will converge to steady-state release policies (Howard, 1960). That is, for $S_n = S_{n+T}$ and for $i_{n-1} = i_{n+T-1}$ then if R_n is the optimal target release for the state $[S_n, i_{n-1}]$ it is also the optimal release for the state $[S_{n+T}, i_{n+T-1}]$. To find the optimal steady-state release policies we may start the algorithm by selecting an arbitrary terminal condition and run the recursive equations for a number of yearly cycles (~10-30) until a steady-state release policy emerges. This is one of the general procedures for solving stationary Markov D-P models*, and from here on we shall refer to Equations (4.18) and (4.19) as the closed loop Markov optimal controller.

To solve Equation (4.18) we will need to work with discrete intervals for the storage intervals, target releases, and streamflows. Let

$\bar{T}$ equal the number of yearly cycles necessary to converge to a steady-state policy

β equal the number of streamflow intervals per period

γ equal the number of storage intervals per period

ξ equal the number of feasible target releases per period

δ equal the number of periods per year

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*This procedure is known as the value-iteration approach. An alternative procedure is the policy iteration approach. Both give the same solution See Howard (1960).

Further let us define a 'unit calculation' as the computational effort required to solve

$$g_n \min(R_n^m, S_n^p + i_n^k) + J_{n+1}(\max(0, S_n^p + i_n^k - R_n^m), i_n^k)$$

for given $1 < m < \xi$, $1 < p < \gamma$, $1 < k < \beta$. Then the number of unit calculations needed before the algorithm converges is

$$\gamma \beta^2 \delta \xi \bar{I} \quad (4.20)$$

The computational effort is quite sensitive to the discretization intervals chosen, with the number of streamflow intervals having a pronounced effect. This is an important observation for while the closed-loop Markov optimal control will, in theory, give us globally optimal solutions (Bertsekas, 1976), there is no guarantee a priori that this will be the case when we discretize continuous variables. Generally, the finer the discretization grid the closer our solution approaches the globally optimal solution, but as we see from Equation (4.20) this will be obtained at ever accelerating computational expense. We are, after all, interested in finding release policies that are reasonably close to the optimal, and we may inquire whether alternative formulations of the stochastic D-P algorithm may better serve our purposes. For this we turn to sub-optimal controllers.

II OPEN-LOOP FEEDBACK CONTROL

The open-loop feedback control is similar to the general form of the closed-loop optimal control with one important exception. At any period t the system will be in some current state, $[s_t, I_t]$, and the problem is to find the optimal cost-to-go from this state on to the terminal state $N-t$

periods away. So far this does not appear very much different from the closed loop optimal control. However, we now introduce the change in formulation by assuming that the information vectors for all periods from t to N will be the current information vector-- I_t . The recursive equation now takes on the form:

At the terminal period

$$J_N[S_N] = \lambda_N[S_N] \quad (4.21)$$

At all periods between t and N (exclusive)

$$J_n[S_n] = \min_{R_n} E_{i_n} \left[g_n \min(R_n, S_n + i_n) + J_{n+1}[\max(0, S_n + i_n - R_n)] \mid I_t \right] \quad (4.22)$$

And at the current period t

$$J_t[S_t] = \min_{R_t} E_{i_t} \left[g_t \min(R_t, S_t + i_t) + J_{t+1}[\max(0, S_t + i_t - R_t)] \mid I_t \right] \quad (4.23)$$

The controller then uses the 'optimal' release, R_t , for the current period and disregards all subsequent release decisions. At the beginning of the next period the current state is updated to its new value and the processes is repeated using the new information vector, I_{t+1} . The open-loop feedback control operated under the assumption that future observations of the information vector will not be made. This is a sub-optimal controller for the reason that it considers only those release policies that ignore future observations of the information vector while the closed-loop optimal control selects from the full set of possible release policies.

Unlike the closed-loop Markov controller, this algorithm does not search for steady-state release policies. Rather, it seeks release policies on a period by period basis. For the design analysis problem, this

means we will run this algorithm along with a streamflow simulation model. At the beginning of every period the past observations of the simulated streamflows are used to update the information vector, I_t . Equations (4.21) thru (4.23) are solved and the optimal target release for the current period, R_t , is applied. The simulation model moves forward one step, calculating both the actual system costs for that period and the storage level at the beginning of the next period. The process then repeats itself.

The primary advantage to this algorithm is that high-order autoregressive processes may be represented in the information vector with no increase in the dimensionality of the problem. This leads to the possibility that the computational requirements may be substantially reduced from that of the closed loop controller. Let Y equal the number of years simulated, and let us further assume that the 'terminal' period is not at a fixed point in time, but is L periods away from the current period at all times. The number of basic calculations required for the full simulation then becomes:

$$\gamma \xi \beta \delta Y L \quad (4.24)$$

We note immediately that the computational effort for this algorithm is less sensitive to the discretization level selected for the streamflows than is the closed-loop optimal control algorithm. In addition the closed loop Markov control requires that the entire set of release decisions for every state at every period be stored for later evaluation in a simulation model. The number of release decisions that must be stored in the computer memory is equal to $\beta \delta Y$. By contrast, the open-loop feedback control operates the simulation model in conjunction with the optimization model

and does not need to save the optimal release decisions for future reference.

A further reduction in computational effort may be realized through the third and final stochastic dynamic programming algorithm examined here: the naive feedback controller.

III THE NAIVE FEEDBACK CONTROL

This algorithm is similar to the open-loop feedback control with the exception that the algorithm uses the conditional expected value of future streamflows, given the current information vector, I_t , and not the full conditional pdf.

Let

$$\hat{i}_n = E \left[i_n \mid I_t \right] \quad t \leq n \leq t+L \quad (4.25)$$

then the naive feedback algorithm becomes:

At the 'terminal' period L periods from now

$$J_{t+L}(S_{t+L}) = \lambda(S_{t+L}) \quad (4.26)$$

At all periods between t and $t+L$ (exclusive)

$$J_n[S_n] = \min_{R_n} \left[q_n \min(R_n, S_n + \hat{i}_n) + J_{n+1}(\max(0, S_n + \hat{i}_n - R_n)) \right] \quad (4.27)$$

And at the current period t

$$J_t[S_t] = \min_{R_t} \left[q_t \min(R_t, S_t + \hat{i}_t) + J_{t+1}(\max(0, S_t + \hat{i}_t - R_t)) \right] \quad (4.28)$$

The naive feedback algorithm is operated in conjunction with a simulation algorithm in the following manner:

1. The current storage level in period t is S_t . We observe the past streamflow information, I_t , and use Equation (4.25) to make a forecast of streamflows for the next L periods.
2. Using the forecasted streamflows, solve the dynamic programming algorithm given in Equations (4.26)-(4.28) and find the optimal target releases, $R_t^*, R_{t+1}^*, \dots, R_{t+L}^*$, for the next L periods.
3. Set the target release for the current period to R_t .
4. Simulate the streamflow for the current period, i_t . The actual release for this period, r_t , is the minimum of R_t , $S_t + i_t$, and the storage level at the beginning of the next period is equal to $S_t + i_t - r_t$. The actual operating cost for this period is $g_t(r_t)$.
5. Record the operating cost and advance to the next period. Return to step 1.

The terminal conditions in Equation (4.26) may be approximated by considering the fact that monthly streamflow forecasts asymptotically approach their respective historic mean values for progressively longer lead times. Consequently, we can solve a deterministic dynamic programming reservoir control problem using average monthly flows for every month, and then assign the value of the optimal cost-to-go from each state in each month to the appropriate boundary condition in the naive feedback control algorithm.

The disadvantages to this model are the same as those for the open-loop feedback control: suboptimal results are obtained and the terminal condition in Equation (4.26) may affect the optimal release selected at every current period, R_t . However it offers all the advantages cited earlier for the open-loop feedback control, particularly in terms of the reduced computational effort needed for a solution. By reformulating a stochastic problem into a series of deterministic problems this algorithm reduces the number of unit calculations to either:

$$\gamma \xi \delta L Y \quad (4.29)$$

or

$$\gamma^2 \delta L Y \quad (4.30)$$

depending on the solution procedure adopted. We notice that this algorithm does not operate with discrete streamflow intervals (β is absent) and thus we have removed a parameter that account for a substantial portion of the computational effort in the closed-loop optimal control.

The naive feedback algorithm frequently reveals a peculiar behavior: the use of conditional expected values of future streamflows (conditional on the current information vector) may lead to poorer performance than using unconditional (e.g. historic) expected streamflows. That is, the algorithm sometimes uses the current information vector to a disadvantage, and in these cases is a 'non-adaptive' controller (Bertsekas, 1976). When this occurs a simpler form of this algorithm can be run using, say, historic monthly streamflows in all forecasts to derive a closed form solution to the reservoir release problem $[R_n = f_n(S_n, n)]$ within $\gamma \xi \delta L$ unit calculations. The stochasticity of the water supply will still be felt vis the frequency with which the reservoir enters a given state (S_n) in

any month. For our purposes we will call the algorithm using the conditional expected streamflows the 'standard' form and the algorithm using the unconditional expected streamflows the 'revised' form.

Some reflection on the revised form of the naive feedback algorithm reveals that it is equivilant to the standard form when monthly streamflows are perfectly independent. However, the revised form will be inferior to the standard form when there is perfect correlation.

This author's experience with the different forms of the dynamic programming algorithm suggests that the selection of one form over another usually involves some trial and error. For example, the closed-loop Markov control, standard naive feedback and revised naive feedback algorithms were compared in one case for a dry-wet tower where the streamflows were highly correlated during the summer months (correlation coeffecient = .8) and moderately correlated during the rest of the year (correlation coeffecients ranging from 0.25 to 0.65). All three algorithms gave roughly similar results when the following parameters were used: $Y = 20$ years; $\delta = 12$ months per year; $L = 6$; $\gamma = 10$ storage levels; $\xi = 10$ release decisions per state; $I = 15$ iterations; and $\beta = 5$ streamflow intervals per period. The Markov algorithm solved the problem with roughly .45 million unit calculations, while the standard and revised forms of the naive feedback algorithms required .144 million and 7200 unit calculations, respectively. However, in another case where monthly streamflows were highly correlated for all months (correlation coeffecient = .9) and summer flows were highly variable (coeffecient of variation = 1.0) both the standard and the revised forms performed worse than a heuristic operating policy. Nevertheless the results from the two sub-optimal controllers revealed where improvements could be made in the heuristic policy.

Where the problem is to evaluate the expected operating costs for a large number of cooling system design/water supply configurations (as is the case with this thesis) the naive feedback algorithm (standard or revised) appears to be a good choice, particularly if the designer has at least one heuristic reservoir operating policy available (the designer can do no worse than the heuristic policy). Where the problem is to develop an operating scheme for a chosen design it appears the closed-loop optimal control algorithm may be the best choice. It has been widely used for problems of this sort, and, in the limit, will lead to optimal control strategies.

A final note on the naive feedback algorithm: equations (4.29) and (4.30) actually represent upper bounds on the number of computations required to solve the algorithm. The convexity of the cost functional $g(\cdot)$ for our particular case insures that in any period there is a single locally optimal (and thus globally optimal) release for each reservoir storage level. Therefore, rather than enumerate over the full set of feasible release decisions in Equations (4.27) and (4.28), the algorithm needs only to search until it finds the locally optimal target release. In addition, the naive feedback algorithm, being a deterministic form of the dynamic programming algorithm, may lend itself to a number of algorithmic 'tricks' that reduce the computational effort further still. In particular, two promising approaches that could be used simultaneously are 'fathoming' (eliminating inferior policies through upper and lower bounds), and 'reaching' (Morin, 1978).

There is one final operations algorithm we will examine for this thesis: the open-loop controller.

IV THE OPEN-LOOP CONTROL

This algorithm follows along the same logic used for the reservoir simulation algorithm presented in Section 4.2, except that fixed reservoir release rules are now sought instead of water right purchases. The open-loop controller searches for the best fixed reservoir release for every month, and is different in this respect from the various dynamic programming methods presented in this chapter. By selecting a fixed policy this algorithm leads to 'conservative' release policies in the sense that releases in any one month are the same regardless of whether the year is a wet one or a dry one. On the other hand plant performance can be predicted with near certainty, a potentially comforting feature for plant operators not found with any of the dynamic programming controllers.

Let us suppose the plant has a make-up water reservoir and define a number of terms:

$S[r=r_1, r_2, \dots, r_{12}]$ denote the set of current fixed cooling system consumption rates (reservoir releases) for the twelve months

$M[S(r)]$ denote the minimum reservoir storage volume observed over a simulated period of operation with the current set of monthly water consumption rates

$M'[S(r)](r_1)$ denote the partial derivative of $M[S(r)]$ with respect to r_1

$g_i'(r_i)$ denote the partial derivative of the loss function in month i with respect to the current fixed release for that month, r_i .

Consider the set $S^*(r)$ for which $M[S^*(r)]$ is positive and arbitrarily close to zero. Then:

$$\Delta r_i = \frac{M[S(r)]}{M'[S(r)]} \quad (4.31)$$

is the approximate increase in r_i which will drive $M[S^*(r)]$ to zero. For $S^*(r)$ to be the optimal set of fixed reservoir releases the following marginal condition must hold:

$$\frac{g_i[r_i]}{M'[S^*(r)](r_i)} = \frac{g_j[r_j]}{M'[S^*(r)](r_j)} \quad \text{all } i, j \quad (4.32)$$

If Equation (4.32) were not met then the plant could increase, by a marginal amount, some releases in some months and decrease, by a marginal amount, releases in others and thus achieve a zero minimum storage level at some point during the period of simulation and gain an increased benefit.

Suppose we have a current set of releases, $S'(r)$ for which the minimum storage volume, $M[S'(r)]$ is much larger than zero. Let $m[S'(r)](r_i)$ represent the minimum simulated storage level if the current release ' r_i ' is increased by one unit. To a first approximation then:

$$M'[S'(r)](r_i) \cong M[S'(r)] - m[S'(r)](r_i) \quad (4.33)$$

The open-loop control algorithm starts with an initial set of fixed monthly releases, evaluates Equations (4.31) and (4.33) for every month over a period of simulation, and selects release r_i^* satisfying the equation:

$$r_i^* = \{r_i \mid \max \{ \frac{g_1[r_1]}{M'[S'(r)](r_1)}, \dots, \frac{g_{12}[r_{12}]}{M'[S'(r)](r_{12})} \} \quad (4.34)$$

The release r_i^* is then incremented by one unit and the algorithm repeats the process until the set of releases $S^*(p)$ is found such that:

$$m[S^*(r)](r_i) = 0 \quad \text{all } i \quad (4.35)$$

This algorithm always strives for local optimality although there is no guarantee that the true globally optimal set of fixed reservoir releases will actually be found. Nevertheless, this approach will always improve any heuristic reservoir release policy. The time required for convergence to a final solution will depend, in large part, on how close the initial set of releases are to optimal. An important attraction of this method is that sensitivity studies can be set up such that the set of optimal fixed policies from one study can serve as the initial set for another study and significantly reduce the amount of time needed to solve the latter.

5.1   INTRODUCTION

As the last three chapters indicate, the design and execution of a good water management plan for an energy facility in the West can be a complex undertaking. In fact, the problem is much larger than we have described it up to this point, for we have examined only one source of water demand, albeit the primary demand at most energy facilities--the evaporative losses from the cooling system. Water is frequently used, though by no means required, for the disposal of the solid wastes generated by a facility--coal ash in the case of coal-fired steam electric power and coal gasification plants, and the spent shale in the case of oil shale plants. Water is used in other activities at a synthetic fuel plant, in some cases appearing in the final product, and in others serving as an intermediary in various mass and heat transport processes.

Even within our myopic view of water use in terms of cooling we are at no loss for the number of decisions that must be made. Which cooling system should be selected? If a storage reservoir is needed how large should it be? If water rights can be purchased, which ones? If the operation of the cooling system can be improved, how should this be done?

Given the pervasive institutional constraints and arrangements in the West for allocating water in general and for 'preferred' uses in particular it is clear that interest in how water will be acquired and used for energy development is not confined to energy firms, but extends

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selection of a cooling system, a reservoir capacity, and a set of water rights rights to purchase for a single facility. For the dry-wet cooling systems the definition of a management strategy is extended to include optimal operating policies.

Obviously no one case study can possibly represent all the conditions affecting the supply of and the demand for water for western energy development. Nevertheless we will use the study in this thesis to develop insight with respect to the alternatives an energy firm may face for acquiring and using water. For this reason we will choose a number of measures to quantify and compare alternative strategies. One that immediately comes to mind is the monetary cost incurred by an energy firm to install a cooling system and, if needed, a make-up water storage reservoir. This could include the costs of acquiring water but we will treat water acquisition as a separate attribute. For our purposes then, we will define 'cost' in terms of all expenditures for plant, equipment, and operation, except those directly associated with water acquisition.

We can treat water acquisition as an attribute either in terms of total water consumption, or in terms of the acquisition and consumption of certain types of water (e.g. purchased water rights). Total water consumption may be relevant from the view of long-term water use in a basin where the allocation of water to energy today may pre-empt potential uses in the future. The purchase and consumption of existing water rights is relevant for a firm which must decide whether there is a net gain to be made by purchasing existing rights in order to supplement

water secured through unappropriated rights. We shall also make the distinction between the the purchase of a water right and its actual use. A management strategy may call for the purchase of certain rights even though the rights are actually used only during rare drought events. This suggests that alternative contractual arrangements might be sought whereby the firm rents, rather than purchases, water rights from existing users during drought periods.

The case study will examine six scenarios for a hypothetical coal-fired steam electric plant on Crazy Woman Creek, Wyoming. The scenarios will involve pair-wise combinations of three reservoir cost alternatives and two plant capacity alternatives. Preliminary studies for this thesis found that water management strategies are highly sensitive to these two factors. For the first plant capacity scenario a single 800 MWe unit is located at the hypothetical site on Crazy Woman Creek. For the second capacity scenario two 800 MWe units are installed. To avoid confusion later on we shall refer to all subsequent cooling systems, reservoir capacities, and water rights purchases on a 'per generating unit' basis. Thus for the two 800 MWe unit scenario a '475-acre' cooling pond will refer to a single pond size for each unit. The three reservoir cost scenarios examine various possible costs for lining and for excavation/diking. These alternative costs are: (1) lining = $\$0/\text{ft}^2$, diking and excavation (D&E) = $\$0.13/\text{ft}^3$; (2) lining = $\$0.3/\text{ft}^2$, D&E = $\$0.2/\text{ft}^3$; (3) lining = $\$0.6/\text{ft}^2$, D&E = $\$0.2/\text{ft}^3$. We will refer to these as the low, medium, and high reservoir cost scenarios, respectively. The diking and excavation costs are representative of costs reported in the literature, while the lining

costs span the range frequently reported for compacted clay liners (Kays, 1977; McDonald and Kline, 1979).

A third factor influencing the selection of a water management strategy is the cost of transporting the cooling system make-up water from the river to an off-stream plant. Transport costs, however, have no effect on the simulation/operation models developed in this thesis, and will be examined in a parametric fashion under each scenario. A fourth factor is the cost of treating the cooling water prior to both use and disposal. Here too, this cost is external to the models used in this thesis and will be examined in a parametric fashion under each scenario.

This case study will not explicitly examine questions of risk. All reservoirs will be designed with sufficient capacity to supply water to their respective cooling systems with 100% reliability during the worst drought observed in the historic record of flows at the case study site. The question of reliability will be raised in Chapter 6 under the heading of additional topics for future research.

The next section will outline the hydrologic and economic inputs used in the case study. The hydrologic inputs include the streamflow statistics past the plant site and the existing demands on the river. The economic parameters include the charges for boiler fuel, replacement energy, replacement capacity costs, and the amortization and discounting rates. In addition, water treatment and transport costs are presented for later use in the parametric studies. The performance

characteristics of the cooling systems themselves were presented in Chapter 3 and will not be repeated here.

5.2 A DESCRIPTION OF THE SITE AND THE INPUTS TO THE MODELS

The site of the hypothetical facility is on the main stem of Crazy Woman Creek, just below the confluence of the Middle, North, and South Forks of Crazy Woman Creek (Figure 5.1). Crazy Woman Creek is a tributary of the Powder River whose headwaters start in the eastern slopes of the Bighorn Mountains in northeastern Wyoming. The primary economic activity on Crazy Woman Creek is agriculture, with land in production above and below the plant site. The basin contains some moderately sized coal deposits although there is currently no mining activity taking place.

5.2.1 HYDROLOGY OF CRAZY WOMAN CREEK

The average annual flow past the plant site for the 18 year period from 1951 to 1968 was 37 cfs, with the primary sources of flow coming from the North and Middle Forks. Three U.S.G.S. gauging stations above the site are the source of the historic flow statistics (Figure 5.1). The case study uses the 18 year record to simulate water availability on the river. The extremes in the annual flows observed during the period of record ranged from a low of 15.5 cfs to a high of over 80 cfs. The annual hydrographs for the average year, the high year, and the low year of record are shown in Figure 5.2. This creek is fed primarily from

FIGURE 5.1 LOCATION OF THE HYPOTHETICAL PLANT
AND IRRIGATORS ON CRAZY WOMAN CREEK

FIGURE 5.2 ILLUSTRATING THE ANNUAL HYDROGRAPHS OBSERVED OVER THE PERIOD OF RECORDED FLOWS ON CRAZY WOMAN CREEK FOR THE HIGH, AVERAGE, AND LOW FLOW YEARS

snowmelt and, as Figure 5.2 illustrates, this leads to a highly skewed distribution of the flow throughout the year, with the peak flows occurring in late Spring and early Summer. Monthly flows are moderately correlated with one another during the Fall and Winter, weakly correlated during the Spring, and strongly correlated during the Summer. Table 5.1 presents the mean, standard deviation, and month-to-month lag-one correlation coefficient for each month. Using the Kolmogorov-Smirnov test, the hypothesis that the streamflows in every month are normally distributed cannot be rejected with a Type 1 error of 10%. This 18 year sequence of streamflows is used to represent virgin river flow conditions past the site in this case study.

The current water use on Crazy Woman Creek is almost entirely for irrigation (Janis, et al., 1977; Wyoming, 1972). There are approximately 2500 acres in irrigation below the site, 4000 acres in irrigation on the North Fork above the site, and smaller amounts of land in irrigation on the South and Middle Forks. The record of flows past the plant site already account for the major upstream diversions, leaving the downstream diversions to contend with. These diversions are almost entirely for alfalfa which will consume, on average, 2 acre-feet per acre during the irrigation season (Janis, et al., 1977; Jensen, 1973). We will make the following assumptions in estimating the monthly irrigation demands below the site: (1) in any season one-quarter of the acres remains fallow; (2) irrigators require 2 cfs in the stream at their headgates for every 1 cfs consumed by their crops (to cover losses that occur during delivery and application); and (3) monthly water application rates (inches) follow those suggested by Jensen (1973).

TABLE 5.1   STATISTICS FOR THE RECORD OF FLOWS ON CRAZY WOMAN
CREEK PAST THE PLANT SITE (cfs)

MONTH	MEAN	VARIANCE	LAG-ONE CORRELATION
1	12.8	9.0	.45
2	14.9	12.3	.47
3	18.8	41.0	.02
4	36.6	412.0	.09
5	76.5	1339.6	.50
6	160.0	24336.0	.23
7	45.6	1421.2	.85
8	17.7	136.9	.58
9	16.3	104.0	.83
10	15.9	34.8	.63
11	16.1	19.4	.68
12	14.6	9.6	.39

These rates are tabulated along with the estimated downstream monthly irrigation demands in Table 5.2. These numbers probably underestimate the true downstream demand as we have not accounted for the instream flows required to operate the diversion pumps. Suffice it to say, these are crude estimates of the downstream water demand; greater precision would be required were this a study for an actual proposed plant.

During the operation of the reservoir simulation/operations models the estimated downstream irrigation demands are subtracted from the streamflows past the site. Flows past the site which are not required to meet the downstream demand are considered 'surplus' flows and are available to the plant without any restrictions.

We will assume any and all existing water rights purchased by the firm will come from the downstream irrigators. Downstream rights purchased by the plant are diverted, along with the 'surplus' flows at the plant's diversion point. We will also adopt the accounting convention that a water 'right' in any month will be defined as one cfs of the most senior water remaining in downstream irrigation use for that month. This convention permits us to differentiate water rights purchase alternatives, and is not intended to represent how the accounting of water rights purchases might actually be done.

**TABLE 5.2   ESTIMATED IRRIGATION WATER DEMANDS AND APPLICATION
RATES BELOW THE PLANT SITE**

APPLICATION RATES (INCHES/MONTH)

APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER
2.2	4.8	3.8	4.8	4.6	3.2	.9

IRRIGATION DEMAND (CFS)

APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER
11.0	23.0	20.0	24.0	24.0	17.0	8.0

5.2.2 ECONOMIC PARAMETERS

The economic parameters used in this thesis are listed in Table 5.4. All parameters are in real dollar values. Boiler fuel costs are given in terms of dollars per thermal megawatt burned in the plant boiler. Replacement energy charges are incurred whenever the plant fails to meet a demand of 800 MWe for each unit. For this case study plant output in excess of 800 MWe for each unit results in a boiler fuel adjustment credit.

The present-valued cost of pumping make-up water to an off-river site is the sum of costs for the pipeline, the pumps, the pumping energy, and the pump power capacity. Assuming water is pumped on a more or less continuous basis year round, the least expensive way of supplying the required pumping power is to design additional capacity into the baseload plant. Appendix 5-A presents the calculations used to calculate the dynamic head loss during transport, the optimal velocity through the pipes, and the required pumping power requirements. The total present-valued cost of transporting water for each cooling system is a linear function of the distance pumped of the form:

$$PVT = A + B \cdot L \quad (5.1)$$

where PVT is the present-valued cost of delivering the make-up water for a given cooling system and L is the pumping distance in miles. The coefficients to Equation (5.1) for each cooling system examined are

TABLE 5.3   STATISTICS FOR THE SURPLUS FLOWS PAST THE
PLANT SITE OVER THE RECORD OF FLOWS ON CRAZY
WOMAN CREEK (cfs)

MONTH	MEAN	VARIANCE
1	12.8	9.0
2	14.9	12.3
3	18.8	41.0
4	25.6	410.9
5	53.6	1332.3
6	139.9	24304.8
7	24.8	1225.0
8	2.7	46.9
9	3.7	52.3
10	7.9	34.8
11	16.1	19.4
12	14.6	9.6

TABLE 5.4 ECONOMIC PARAMETERS

BOILER ENERGY:	\$0.031/KWHt
REPLACEMENT ENERGY:	\$0.30/KWHe
MAKE-UP WATER TREATMENT:	\$0.30/1000 gal
REPLACEMENT CAPACITY:	\$160/KWe
BASELOAD CAPACITY:	\$600/KWe
DISCOUNT RATE (INFLATION FREE):	4.0%
FIXED CHARGE RATE:	11.0%

TABLE 5.5 COEFFICIENTS USED TO CALCULATE MAKE-UP WATER TRANSPORT COSTS (\$ MILLIONS)

COOLING SYSTEM	FLOW (cfs)	A	B
475 ACRE COOLING POND	12.2	2.5	1.43
800 ACRE COOLING POND	14.0	3.0	1.54
500 FOOT COOLING TOWER	11.6	2.5	1.40
40% DRY-WET TOWER	4.2	0.9	0.84
30% DRY-WET TOWER	5.2	1.1	0.94
DRY TOWER-COOLING POND	5.2	1.1	0.94

given in Table 5.5.

In this thesis operation and maintenance costs will be given in present-valued dollars. All annual costs are simply discounted over the plant's 40 year lifetime. Initial capital costs, on the other hand, are first annualized using the fixed charge rate and then discounted with the real dollar discount rate. As the fixed charge rate includes taxes, interest payments, insurance, and depreciation this approach accounts for the full discounted lifetime cost of owning a piece of equipment.

5.3 RESULTS FROM THE SIMULATION/OPERATIONS MODELS

5.3.1 THE COOLING PONDS

Tables 5.6 and 5.7 list a number of the feasible non-inferior combinations of active storage capacity and irrigation rights purchases for the 475 acre and the 800 acre cooling ponds, respectively, under the single 800 MWe unit scenario. These are non-inferior combinations in the sense that for a fixed reservoir capacity we have identified the minimum number of water rights the plant can purchase to insure the reservoir will not run dry during the 18 years of historic streamflows. Tables 5.8 and 5.9 repeat the feasible non-inferior combinations for the dual 800 MWe unit scenario. These non-inferior combinations have been identified using the reservoir simulation/water rights acquisition algorithm presented in Section 4.2 of Chapter 4. Since the ponds have fixed surface areas the active storage capacities are simply proportional to the depths of the ponds. These tables also indicate how

TABLE 5.6 NON-INFERIOR COMBINATIONS OF RESERVOIR STORAGE AND IRRIGATION WATER RIGHT PURCHASES (PER UNIT) FOR THE 475 ACRE COOLING POND: SINGLE UNIT SCENARIO

AREA (ac)	DEPTH (ft)	WATER RIGHT PURCHASES (CFS)							TOTAL (acre-feet)
		APR	MAY	JUN	JUL	AUG	SEP	OCT	
	5	0	13	18	12	8	7	8	3870
	10	0	0	11	12	8	7	8	2680
	15	0	0	0	3	8	7	8	1490
	20	0	0	0	0	0	0	2	120

TABLE 5.7 NON-INFERIOR COMBINATIONS OF RESERVOIR STORAGE AND IRRIGATION WATER RIGHT PURCHASES (PER UNIT) FOR THE 800 ACRE COOLING POND: SINGLE UNIT SCENARIO

AREA (ac)	DEPTH (ft)	WATER RIGHT PURCHASES (CFS)							TOTAL (acre-feet)
		APR	MAY	JUN	JUL	AUG	SEP	OCT	
	4	5	23	20	13	8	9	8	5060
	8	0	0	19	11	8	10	8	3280
	12	0	0	0	4	8	9	8	1610
	15.4	0	0	0	0	0	0	0	0

TABLE 5.8   NON-INFERIOR COMBINATIONS OF RESERVOIR STORAGE AND
IRRIGATION WATER RIGHT PURCHASES (PER UNIT) FOR THE
475 ACRE COOLING POND: TWO UNIT SCENARIO

AREA (ac)	DEPTH (ft)	WATER RIGHT PURCHASES (CFS)							TOTAL (acre-feet)
		APR	MAY	JUN	JUL	AUG	SEP	OCT	
	20	0	2	10	12	5	7	4	2390
	25	0	0	1	12	5	7	4	1670
	35	0	0	0	1	5	6	4	1000
	45	0	0	0	0	0	3	4	420
	53.8	0	0	0	0	0	0	0	0

TABLE 5.9   NON-INFERIOR COMBINATIONS OF RESERVOIR STORAGE AND
IRRIGATION WATER RIGHT PURCHASES (PER UNIT) FOR THE
800 ACRE COOLING POND: TWO UNIT SCENARIO

AREA (ac)	DEPTH (ft)	WATER RIGHT PURCHASES (CFS)							TOTAL (acre-feet)
		APR	MAY	JUN	JUL	AUG	SEP	OCT	
	10	5	12	10	12	12	8	4	3750
	15	2	12	10	12	5	8	4	3070
	20	0	5	10	12	5	8	4	2560
	25	0	0	7	12	5	7	4	2090
	35	0	0	0	3	5	7	4	1130
	47.1	0	0	0	0	0	0	0	0

many water rights are purchased in every month under each combination. The evolution of the non-inferior monthly rights purchases for progressively larger reservoir capacities appear intuitively correct. That is, as the active storage capacity increases the non-inferior set of rights purchased by the plant collapses to rights that deliver during months when streamflows are frequently less than the plant water demand (e.g., September and October).

The most critical month for the plant to have access to irrigation rights is October. We observe in Tables 5.6-5.9 that rights delivery in October are sought for every strategy under which the firm purchases water rights. We will be able to assess the firm's opportunity value for having access to October rights in Section 5.4 when we assign costs to constructing different reservoir capacities. We also notice the firm rarely purchases more than half of the total rights potentially 'available' in the months August thru October. This is because of the total estimated potential irrigation demand downstream of the site only a fraction will be consistently met during these months. Junior water rights are rarely satisfied and consequently they have only marginal value to the firm.

The least critical months for the plant to have access to irrigation rights are during April and May. In pursuing the most efficient water rights purchase strategy the firm will acquire rights for these months only when it installs relatively small storage reservoirs under either of the two plant capacity scenarios.

We can pursue a more complete assessment of the relative importance the firm will place on access to irrigation rights in different months. We will do this by examining the frequencies with which the firm will 'call out' any rights it has purchased. A 'call' on a right is a notice to other users on the river that the owner wishes to divert the legally available flow decreed by the right during a certain period. The holder of the senior-most rights on a river may, at any time, 'call' out either the entire flow decreed by those rights or the entire streamflow in the river, whichever is the smaller.

Tables 5.10 and 5.11 list the frequencies with which rights are called under the single unit scenario for the 475 acre and the 800 acre cooling ponds, respectively, and Tables 5.12 and 5.13 give the frequencies observed under the two unit scenario. Since we have assumed the plant purchases the most senior rights on Crazy Woman Creek then anytime the plant wishes to call out all of its rights in a particular month it will actually receive the full allotment of its rights or the available streamflow, whichever is smaller.

Interestingly enough, we find that for both cooling ponds under the single unit scenario rights purchased between April and June go completely uncalled most of the time. For the 475 acre cooling pond water rights purchased for delivery in May and June need not be diverted roughly 80% of the time while rights purchased for July go uncalled roughly 55% of the time. Similar results are observed for the 800 acre cooling pond with the notable exception that in most years the plant will call out at least some of the July rights it has purchased. Water

TABLE 5.10 FREQUENCIES WITH WHICH THE PLANT WILL CALL
OUT PURCHASED IRRIGATION WATER RIGHTS FOR THE
475 ACRE COOLING POND: SINGLE GENERATING UNIT
SCENARIO

ACTIVE RESERVOIR STORAGE CAPACITY: 475 ACRES BY 5 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED: 3875 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)									
		0	2	4	6	8	10	12	14	16	18
MAY	13	.78	.0	.0	.06	.0	.0	.16			
JUN	18	.83	.0	.0	.0	.0	.0	.0	.0	.0	.17
JUL	12	.56	.0	.05	.06	.0	.0	.33			
AUG	8	.0	.0	.0	.0	1.0					
SEP	7	.0	.0	.0	1.0						
OCT	8	.0	.0	.0	.0	1.0					

TABLE 5.10 (cont) FREQUENCIES WITH WHICH THE PLANT WILL CALL
OUT PURCHASED IRRIGATION WATER RIGHTS FOR THE
475 ACRE COOLING POND: SINGLE GENERATING UNIT
SCENARIO

ACTIVE RESERVOIR STORAGE CAPACITY: 475 ACRES BY 10 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED: 2680 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
JUN	11	.83	.0	.0	.0	.0	.17	
JUL	12	.56	.0	.05	.0	.06	.0	.33
AUG	8	.0	.0	.0	.0	1.0		
SEP	7	.05	.0	.0	.95			
OCT	8	.17	.0	.0	.05	.78		

ACTIVE RESERVOIR STORAGE CAPACITY: 475 ACRES BY 15 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED: 1490 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
JUL	3	.56	.44					
AUG	8	.0	.0	.0	.0	1.0		
SEP	7	.0	.0	.0	1.0			
OCT	8	.17	.0	.0	.05	.78		

TABLE 5.11 FREQUENCIES WITH WHICH THE PLANT WILL CALL
OUT PURCHASED IRRIGATION WATER RIGHTS FOR THE
800 ACRE COOLING POND: SINGLE GENERATING UNIT
SCENARIO

ACTIVE RESERVOIR STORAGE CAPACITY: 800 ACRES BY 4 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED: 5065 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)											
		0	2	4	6	8	10	12	14	16	18	20	22
APR	5	.56	.0	.44									
MAY	23	.61	.0	.0	.0	.06	.06	.0	.0	.0	.0	.0	.27
JUN	20	.78	.0	.0	.0	.0	.0	.0	.0	.0	.0	.22	
JUL	13	.39	.0	.0	.0	.06	.0	.55					
AUG	8	.0	.0	.0	.0	1.0							
SEP	9	.0	.0	.0	.0	1.0							
OCT	8	.0	.0	.0	.0	1.0							

TABLE 5.11 (cont) FREUENCIES WITH WHICH THE PLANT WILL CALL
OUT PUECHASED IRRIGATION WATER RIGHTS FOR THE
800 ACEE COOLING POND: SINGLE GENERATING UNIT
SCENARIO

ACTIVE RESERVOIR STORAGE CAPACITY: 800 ACRES BY 8 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED: 3280 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)										
		0	2	4	6	8	10	12	14	16	18	20 22
JUN	19	.78	.0	.0	.0	.0	.0	.0	.0	.0	.22	
JUL	11	.33	.06	.0	.0	.0	.61					
AUG	8	.0	.0	.0	.0	1.0						
SEP	10	.0	.0	.0	.0	.0	1.0					
OCT	8	.0	.0	.0	.0	1.0						

TABLE 5.11 (cont) FREQUENCIES WITH WHICH THE PLANT WILL CALL
OUT PURCHASED IRRIGATION WATER RIGHTS FOR THE
800 ACRE COOLING POND: SINGLE GENERATING UNIT
SCENARIO

ACTIVE RESERVOIR STORAGE CAPACITY: 800 ACRES BY 12 FEET
TOTAL IRRIGATION WATER RIGHT PURCHASES: 1610 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)				
		0	2	4	6	8
JUL	4	.36	.0	.84		
AUG	8	.0	.0	.0	.0	1.0
SEP	9	.0	.0	.0	.0	1.0
OCT	8	.0	.0	.0	.0	1.0

TABLE 5.12 FREQUENCIES WITH WHICH THE PLANT WILL CALL OUT PURCHASED IRRIGATION WATER RIGHTS FOR THE 475 ACRE COOLING POND: DUAL GENERATING UNIT SCENARIO

ACTIVE RESERVOIR STORAGE CAPACITY (PER UNIT): 475 ACRES BY 20 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED (PER UNIT): 2390 ACRE-Feet

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
MAY	2	.33	.67					
JUN	10	.61	.0	.0	.0	.0	.39	
JUL	12	.28	.0	.0	.06	.06	.05	.55
AUG	5	.0	.0	1.0				
SEP	7	.0	.0	.0	1.0			
OCT	4	.0	.0	1.0				

ACTIVE RESERVOIR STORAGE CAPACITY (PER UNIT): 475 ACRES BY 25 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED (PER UNIT): 1670 ACRE-Feet

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
JUN	1	1.0						
JUL	12	.28	.0	.0	.06	.06	.05	.55
AUG	5	.0	.0	1.0				
SEP	7	.0	.0	.0	1.0			
OCT	4	.0	.0	1.0				

TABLE 5.12 (cont) FREQUENCIES WITH WHICH THE PLANT WILL CALL
OUT PURCHASED IRRIGATION WATER RIGHTS FOR THE
475 ACRE COOLING POND: DUAL GENERATING UNIT
SCENARIO

ACTIVE RESERVOIR STORAGE CAPACITY (PER UNIT): 475 ACRES BY 35 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED (PER UNIT): 1000 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
JUL	1	1.0						
AUG	5	.0	.0	1.0				
SEP	6	.0	.0	.0	1.0			
OCT	4	.0	.0	1.0				

ACTIVE RESERVOIR STORAGE CAPACITY (PER UNIT): 475 ACRES BY 45 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED (PER UNIT): 415 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
SEP	3	.0	1.0					
OCT	4	.0	.0	1.0				

TABLE 5.13 FREQUENCIES WITH WHICH THE PLANT WILL CALL
OUT PURCHASED IRRIGATION WATER RIGHTS FOR THE
800 ACRE COOLING POND: DUAL GENERATING UNIT
SCENARIO

ACTIVE RESERVOIR STORAGE CAPACITY (PER UNIT): 800 ACRES BY 10 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED (PER UNIT): 3750 ACRE-Feet

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
APR	5	.11	.06	.83				
MAY	12	.28	.05	.0	.0	.0	.0	.67
JUN	10	.56	.0	.0	.0	.0	.44	
JUL	12	.17	.0	.0	.06	.06	.0	.71
AUG	12	.0	.0	.0	.0	.0	.0	1.0
SEP	8	.0	.0	.0	.0	1.0		
OCT	7	.0	.0	.0	1.0			

ACTIVE RESERVOIR STORAGE CAPACITY (PER UNIT): 800 ACRES BY 15 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED (PER UNIT): 3070 ACRE-Feet

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
APR	2	.11	.89					
MAY	12	.22	.0	.0	.05	.0	.0	.73
JUN	10	.53	.0	.0	.0	.0	.47	
JUL	12	.11	.0	.06	.06	.06	.0	.71
AUG	5	.0	.0	1.0				
SEP	8	.0	.0	.0	.0	1.0		
OCT	4	.0	.0	1.0				

TABLE 5.13 (cont) FREQUENCIES WITH WHICH THE PLANT WILL CALL
OUT PURCHASED IRRIGATION WATER RIGHTS FOR THE
800 ACRE COOLING POND: DUAL GENERATING UNIT
SCENARIO

ACTIVE RESERVOIR STORAGE CAPACITY (PER UNIT): 800 ACRES BY 25 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED (PER UNIT): 2085 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
JUN	7	.46	.0	.0	.57			
JUL	12	.14	.0	.0	.06	.04	.0	.75
AUG	5	.0	.0	1.0				
SEP	8	.0	.0	.0	.0	1.0		
OCT	4	.0	.0	1.0				

ACTIVE RESERVOIR STORAGE CAPACITY (PER UNIT): 800 ACRES BY 35 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED (PER UNIT): 1130 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
JUL	3	.11	.89					
AUG	5	.0	.0	1.0				
SEP	7	.0	.0	.0	1.0			
OCT	4	.0	.0	1.0				

rights purchased for delivery during the late Summer are consistently called when the plant operates with either of the two cooling ponds under the single unit scenario.

Under the two unit scenario the plant will consistently call the full allotment of any rights purchased. The only exception occurs in June when the plant will call none of its June rights roughly 55% of the years with the 475 acre pond and a little over half the time with the 800 acre cooling pond.

We can enhance our conceptual understanding of these results by examining some additional statistics. Let us define a new statistic, the expected surplus flow available to the plant in month j , $\bar{X}_j$, where:

$$\bar{X}_j = E[\max[0, X_{i,j} - D_j]] \quad (5.2)$$

where:

X_{ij} = The total flow past the plant in year i , month j (cfs)

D_j = The downstream irrigation demand in month j (cfs).

Let us denote the standard deviation around $\bar{X}_j$ by σ_j . Next, for a given cooling system let us define an 'expected normalized flow deficit' in every month j , $ENFD_j^k$, where:

$$ENFD_j^k = \frac{R_j^k - \bar{X}_j}{\sigma_j} \quad (5.3)$$

where R_j^k = the water demand from cooling system k in month j.

The expected normalized flow deficit is an indicator of the probability that the plant cooling system water demand will exceed the surplus flows available to the plant in month i. If surplus flows are normally distributed in every month then a value of ENFD greater than zero indicates this probability is at least 0.5, while for values of ENFD less than zero this probability is less than 0.5. The assumption that surplus flows are normally distributed, as it turns out, holds quite well on Crazy Woman Creek except for the months of August and September.

Figures 5.3 and 5.4 illustrate the expected normalized flow deficits throughout a year for the two cooling ponds under the single unit and the dual unit scenarios, respectively. Under the single unit scenario the surplus flows tend to refill the ponds from November to June while the pond storage volumes are drawn down from July to October. The peak expected normalized flow deficit occurs in August, although we noted earlier that the most critical month for the plant to purchase irrigation rights is October. The two driest months, July and August, are preceded by the wet months of May and June while September and October are preceded by two months of low flows.

Under the two unit scenario surplus flows tend to refill the ponds from November to June, but the refill is less in this case than under the single unit scenario. There is negligible refill during April for the 475 acre pond and a slight net drawdown in this month for the 800

FIGURE 5.3 THE MONTHLY EXPECTED NORMALIZED FLOW DEFICITS FOR THE 470 AND 800 ACRE COOLING PONDS: SINGLE GENERATING UNIT SCENARIO

FIGURE 5.4 THE MONTHLY EXPECTED NORMALIZED FLOW DEFICITS FOR THE 470
AND 800 ACRE COOLING PONDS: DUAL GENERATING UNIT SCENARIO

acre pond. The maximum refill occurs in June and this is consistent with our earlier observation that rights purchased for delivery during this month will go uncalled for most years.

5.3.2 WET COOLING TOWER

Tables 5.14 and 5.15 list a number of the feasible non-inferior combinations of active storage capacity and irrigation rights purchases for the 500 foot wet cooling tower under the single unit and the double unit scenarios, respectively. The non-inferior storage-purchase combinations appear quite similar to those observed in the previous section for the two cooling ponds. The most critical months for the plant to have access to water rights are September and October while the least critical months are April, May and June. The frequencies with which the plant will actually call out purchased rights are given in Tables 5.16 and 5.17 for the single unit and the double unit scenarios, respectively. For the single unit scenario water rights purchased for the months April thru July go uncalled for most years. Under the two unit scenario only rights purchased for June go uncalled for most years. Again, these results are quite similar to those found for the two cooling ponds.

Figure 5.5 illustrates the expected normalized flow deficit over the year for the two separate plant capacity scenarios. The deficits are consistently negative from November to July in the single unit case, indicating that, on the average, the plant reservoir will accumulate water during this period. With two units installed at the plant,

TABLE 5.14   NON-INFERIOR COMBINATIONS OF RESERVOIR STORAGE AND
IRRIGATION WATER RIGHT PURCHASES (PER UNIT) FOR THE
500-FOOT COOLING TOWER: SINGLE UNIT SCENARIO

AREA (ac)	DEPTH (ft)	WATER RIGHT PURCHASES (CFS)							TOTAL (acre-feet)
		APR 11	MAY 23	JUN 20	JUL 24	AUG 24	SEP 17	OCT 8	
50	10								7500
100	15	0	10	12	12	8	6	8	3280
150	20	0	0	11	16	8	6	8	2680
200	25	0	0	0	9	7	6	8	1730
250	30	0	0	0	0	0	3	7	600
291.8	30	0	0	0	0	0	0	0	0

TABLE 5.15   NON-INFERIOR COMBINATIONS OF RESERVOIR STORAGE AND
IRRIGATION WATER RIGHT PURCHASES (PER UNIT) FOR THE
500 FOOT COOLING TOWER: TWO UNIT SCENARIO

AREA (ac)	DEPTH (ft)	WATER RIGHT PURCHASES (CFS)							TOTAL (acre-feet)
		APR 5	MAY 12	JUN 10	JUL 6	AUG 5	SEP 7	OCT 4	
145	55								2950
250	55	0	0	2	6	5	7	4	1430
375	55	0	0	0	3	5	7	4	1100
675	55	0	0	0	0	0	2	4	390

TABLE 5.16 FREQUENCIES WITH WHICH THE PLANT WILL CALL
OUT PURCHASED IRRIGATION WATER RIGHTS FOR THE
500 FOOT WET COOLING TOWER: SINGLE GENERATING
UNIT SCENARIO

ACTIVE RESERVOIR STORAGE CAPACITY: 50 ACRES BY 10 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED: 7500 ACRE-Feet

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)											
		0	2	4	6	8	10	12	14	16	18	20	22
APR	11	.77	.04	.04	.0	.03	.12						
MAY	23	.89	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.11
JUN	20	.86	.0	.0	.0	.0	.0	.0	.0	.0	.0	.14	
JUL	23	.67	.0	.04	.02	.0	.03	.0	.03	.03	.0	.0	.18
AUG	23	.09	.0	.05	.05	.02	.09	.05	.04	.12	.08	.10	.31
SEP	17	.10	.05	.06	.05	.05	.04	.15	.14	.35			
OCT	8	.32	.15	.10	.13	.30							

TABLE 5.16 (cont) FREQUENCIES WITH WHICH THE PLANT WILL CALL
OUT PURCHASED IRRIGATION WATER RIGHTS FOR THE
500 FOOT WET COOLING TOWER: SINGLE GENERATING
UNIT SCENARIO

ACTIVE RESERVOIR STORAGE CAPACITY: 100 ACRES BY 15 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED: 3280 ACRE-Feet

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
MAY	10	.86	.0	.0	.0	.0	.14	
JUN	12	.86	.0	.0	.0	.0	.0	.14
JUL	12	.68	.0	.03	.02	.0	.03	.24
AUG	8	.07	.0	.04	.02	.88		
SEP	6	.09	.04	.05	.82			
OCT	8	.17	.06	.0	.05	.72		

ACTIVE RESERVOIR STORAGE CAPACITY: 200 ACRES BY 25 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED: 1730 ACRE-Feet

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
JUL	9	.65	.05	.0	.0	.30		
AUG	7	.05	.03	.04	.88			
SEP	6	.05	.05	.05	.85			
OCT	8	.14	.06	.0	.04	.76		

TABLE 5.17 FREQUENCIES WITH WHICH THE PLANT WILL CALL
OUT PURCHASED IRRIGATION WATER RIGHTS FOR THE
500 FOOT WET COOLING TOWER: DUAL GENERATING
UNIT SCENARIO

ACTIVE RESERVOIR STORAGE CAPACITY (PER UNIT): 145 ACRES BY 55 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED (PER UNIT): 2950 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
APR	5	.07	.0	.93				
MAY	12	.32	.0	.05	.05	.0	.0	.58
JUN	10	.67	.0	.0	.0	.03	.30	
JUL	6	.43	.06	.05	.46			
AUG	5	.0	.0	1.0				
SEP	7	.0	.0	.0	1.0			
OCT	4	.0	.0	1.0				

ACTIVE RESERVOIR STORAGE CAPACITY (PER UNIT): 250 ACRES BY 55 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED (PER UNIT): 1430 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
JUN	2	.51	.49					
JUL	6	.37	.05	.0	.58			
AUG	5	.0	.0	1.0				
SEP	7	.0	.0	.0	1.0			
OCT	4	.0	.0	1.0				

TABLE 5.17 (cont) FREQUENCIES WITH WHICH THE PLANT WILL CALL
OUT PURCHASED IRRIGATION WATER RIGHTS FOR THE
500 FOOT WET COOLING TOWER: DUAL GENERATING
UNIT SCENARIO

ACTIVE RESERVOIR STORAGE CAPACITY (PER UNIT): 375 ACRES BY 55 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED (PER UNIT): 1100 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)					
		0	2	4	6	8	10 12
JUL	3	.30	.70				
AUG	5	.0	.0	1.0			
SEP	7	.0	.0	.0	1.0		
OCT	4	.0	.0	1.0			

ACTIVE RESERVOIR STORAGE CAPACITY (PER UNIT): 675 ACRES BY 55 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED (PER UNIT): 385 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)					
		0	2	4	6	8	10 12
SEP	2	.0	1.0				
OCT	4	.0	.0	1.0			

FIGURE 5.5 THE MONTHLY EXPECTED NORMALIZED FLOW DEFICITS FOR THE 500 FOOT WET COOLING TOWER: SINGLE AND DUAL GENERATING UNIT SCENARIOS

however, the net accumulation of water in the reservoir will occur only from March to June. Furthermore, large reservoir capacities are required to capture the peak flows that come in June if the plant is to have sufficient water for the nine months of no accumulation. The wet cooling towers must not only have enough storage capacity on hand to capture the June runoff, but must have additional capacity to compensate for the reservoir surface evaporative losses themselves. In fact, the reservoir capacities required by the wet cooling tower under this scenario are larger than the active capacities needed by the 475 acre pond for all irrigation right purchase alternatives.

5.3.3 THE DRY-WET COOLING SYSTEMS

The dry-wet cooling systems, it will be recalled, allow the plant operators some latitude in selecting the operating mode during any month. For this thesis we define the operating mode in terms of the relative number of dry and wet heat exchangers in operation during any month. For each mode there is an expected net plant power output accompanied by an expected make-up water demand rate. In Chapter 4 we presented various algorithms a plant designer might use to optimize the operating schedule for a dry-wet system, given restrictions on the amount of active reservoir capacity available for make-up water storage and water supply limitations (with or without additional water right purchases).

For each of the three dry-wet systems examined in this case study we will first specify a fixed, heuristic operating schedule. This

heuristic policy, in turn, defines both the expected net power output and the expected water consumption for every month. This schedule is used to select feasible combinations of reservoir storage and irrigation right purchases using the same reservoir simulation/search algorithm used for the cooling ponds and the wet cooling tower. We then use one of the operations algorithms described in Chapter 4 to improve the heuristic policy and reduce operating costs. Initial results suggest the naive-feedback control (NFC) algorithm operates quite well with the 40% dry-60% wet cooling tower. Recall from Chapter 3 that this cooling system can operate quite satisfactorily with relatively little water consumption during the hot summer months. The additional dry cooling capacity built into the system compensates for infrequent occasions when the NFC algorithm leads to non-optimal operating policies. By contrast, the 30% dry-70% wet cooling tower and the 50% dry tower-50% cooling pond have relatively little dry cooling capacity to fall back on during the summer months. It is for this reason that these two systems operate better under the more conservative open-loop control (OLC) algorithm than under the NFC algorithm.

I THE 40% DRY-60% WET COOLING TOWER

Table 5.18 gives the heuristic operating policy used for the 40% dry 60% wet cooling tower. Referring back to Figure 3.9, which illustrates the monthly net power output as a function of make-up water consumption for every month, we find this is a fairly conservative policy in terms of overall water use, but is one for which the net power will never fall below 793 MWe per generating unit.

TABLE 5.18 HEURISTIC OPERATING POLICY FOR THE 40% DRY-
60% WET COOLING TOWER

MONTH	EVAPORATIVE LOSS (cfs)	NET POWER OUTPUT (MW _e)
JAN	0.0	807.1
FEB	0.0	804.6
MAR	0.0	801.6
APR	.9	793.3
MAY	3.7	793.0
JUN	5.5	793.0
JUL	6.5	793.0
AUG	6.0	793.0
SEP	4.1	794.0
OCT	1.2	794.0
NOV	0.0	799.0
DEC	0.0	803.3

Tables 5.19 and 5.20 show how the firm may substitute reservoir storage for purchases of irrigation rights using the heuristic policy under the single unit and dual unit scenarios, respectively. As with the other cooling systems examined so far, a consistent pattern emerges with respect to the most critical months for water supply. Under both plant capacity scenarios the most critical months are August and September, with October a critical month for the two unit scenario as well. Deliveries during April, May, and June, on the other hand, are required only when the plant has installed a relatively small reservoir.

The NFC algorithm leads to a noticable reduction in the operating cost realized under the heuristic policy. For both plant capacity scenarios operating costs are reduced, on average, by \$.67 million per year at all combinations of reservoir storage and irrigation water purchases. In addition, the average make-up water consumption increases from 2.3 cfs under the heuristic policy to an average of 4.2 cfs with the NFC policy. The savings in operating cost is roughly equal to one-half of the difference between the operating cost of the wet cooling tower and the operating cost of the 40% dry-60% wet tower under the heuristic policy.

In Figure 5.6 the average and the minimum make-up water consumption rates for every month under the NFC policy are compared with the monthly consumption rates for the heuristic policy for the dual unit scenario where a combined reservoir storage for both units of 150 acres by 25 feet (active storage depth) is installed. For this case the plant appropriates only the surplus flows on the creek. The average

TABLE 5.19

NON-INFERIOR COMBINATIONS OF RESERVOIR STORAGE AND
IRRIGATION WATER RIGHT PURCHASES (PER UNIT) FOR THE
40% DRY-WET COOLING TOWER: SINGLE UNIT SCENARIO

AREA (ac)	DEPTH (ft)	WATER RIGHT PURCHASES (CFS)							TOTAL (acre-feet)
		APR	MAY	JUN	JUL	AUG	SEP	OCT	
10	10	0	3	3	7	7	4	1	1430
30	15	0	0	2	7	7	4	0	1130
50	20	0	0	0	0	7	4	0	600
71.6	25	0	0	0	0	0	0	0	0

TABLE 5.20

NON-INFERIOR COMBINATIONS OF RESERVOIR STORAGE AND
IRRIGATION WATER RIGHT PURCHASES (PER UNIT) FOR THE
40% DRY-WET COOLING TOWER: TWO UNIT SCENARIO

AREA (ac)	DEPTH (ft)	WATER RIGHT PURCHASES (CFS)							TOTAL (acre-feet)
		APR	MAY	JUN	JUL	AUG	SEP	OCT	
30	15	0	1	5	7	4	3	2	1320
50	20	0	0	0	4	3	3	2	720
60	25	0	0	0	0	0	3	1	240
77	25	0	0	0	0	0	0	0	0

FIGURE 5.6 MONTHLY MAKE-UP WATER CONSUMPTION FOR THE 40% DRY-WET COOLING TOWER UNDER THE HEURISTIC AND THE NFC OPERATING POLICIES

consumption under the NFC policy is not only greater than the consumption under the heuristic policy in almost all months, but, with only a few exceptions, is equal to the maximum consumption possible in every month for this cooling system as well. The dotted line in this figure denotes the minimum water consumption allowed by the NFC algorithm over the 18 year period. We find that deviations from the maximum possible consumption occurred in a single year (year 11) and lasted from July to October. The dry-wet tower operated with the wet cooling towers at full capacity year round for the remaining 17 years of simulation. This pattern is repeated in almost exact detail for the other reservoir/water right purchase alternatives presented for the two plant capacity scenarios: there is a single drought year (year 11) when the NFC policy shuts down some of the wet cooling tower sections to conserve water. In no case did the deviation from the maximum level of wet tower operation last more than four consecutive months.

The plant usually suffers a severe reduction in power output when the NFC policy makes a maximum effort to conserve water. This deficit between supply and demand ranges from 8 to 89 MWe per unit (ave. = 41 MWe) for the two capacity scenarios, as compared with the maximum difference between desired and actual output of 7 MWe for the heuristic operating policy. There is little reason to suspect, however, that a utility will invest in generating capacity which will remain idle all but one month every eighteen years. A loss of 89 MWe represents 11% of the total unit capacity, and might be made-up elsewhere in a utility's system or through the purchase of power from neighboring utilities. By contrast, the mean time between a complete shutdown for a steam-electric

TABLE 5.21 FREQUENCIES WITH WHICH THE PLANT WILL CALL
OUT PURCHASED IRRIGATION WATER RIGHTS FOR THE
40% DRY-60% WET COOLING TOWER: SINGLE GENERATING
UNIT SCENARIO

ACTIVE RESERVOIR STORAGE CAPACITY: 10 ACRES BY 10 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED: 1430 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
MAY	3	.94	.06					
JUN	3	.89	.11					
JUL	7	.72	.0	.06	.22			
AUG	7	.17	.0	.06	.77			
SEP	4	.22	.06	.72				
OCT	1	1.0						

ACTIVE RESERVOIR STORAGE CAPACITY: 30 ACRES BY 15 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED: 1130 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
JUN	2	.89	.11					
JUL	7	.72	.0	.06	.22			
AUG	7	.17	.0	.06	.77			
SEP	4	.22	.06	.72				

TABLE 5.21 (cont) FREQUENCIES WITH WHICH THE PLANT WILL CALL
OUT PURCHASED IRRIGATION WATER RIGHTS FOR THE
40% DRY-60% WET COOLING TOWER: SINGLE GENERATING
UNIT SCENARIO

ACTIVE RESERVOIR STORAGE CAPACITY: 50 ACRES BY 20 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED: 600 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
AUG	7	.17	.0	.06	.77			
SEP	4	.22	.06	.72				

TABLE 5.22 FREQUENCIES WITH WHICH THE PLANT WILL CALL
OUT PURCHASED IRRIGATION WATER RIGHTS FOR THE
40% DRY-60% WET COOLING TOWER: DUAL GENERATING
UNIT SCENARIO

ACTIVE RESERVOIR STORAGE CAPACITY (PER UNIT): 30 ACRES BY 15 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED (PER UNIT): 1320 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
MAY	1	1.0						
JUN	5	.89	.0	.11				
JUL	7	.72	.11	.0	.17			
AUG	4	.17	.06	.77				
SEP	3	.22	.78					
OCT	2	.33	.67					

ACTIVE RESERVOIR STORAGE CAPACITY (PER UNIT): 50 ACRES BY 20 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED (PER UNIT): 720 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
JUL	4	.72	.11	.17				
AUG	3	.11	.89					
SEP	3	.22	.78					
OCT	2	.28	.72					

TABLE 5.22 (cont) FREQUENCIES WITH WHICH THE PLANT WILL CALL
OUT PURCHASED IRRIGATION WATER RIGHTS FOR THE
40% DRY-60% WET COOLING TOWER: DUAL GENERATING
UNIT SCENARIO

ACTIVE RESERVOIR STORAGE CAPACITY (PER UNIT): 60 ACRES BY 25 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED (PER UNIT): 240 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)					
		0	2	4	6	8	10 12
SEP	3	.11	.89				
OCT	1	1.0					

generating unit is approximately half a year, and lasts approximately 5 days (EEI, 1975). Furthermore, the NFC algorithm will warn the plant operators several months in advance of the probability of a partial outage in the future; preparations can be made to replace the lost power through any number of means.

For this thesis we will adopt the assumption that the energy firm will purchase the replacement energy required during one-time losses in plant output. The cost of replacement energy is set at \$.03/kwh_e

The frequencies with which the plant will actually need to call out irrigation rights purchased when operating with the NFC policy for the two capacity scenarios are given in Tables 5.21 and 5.22. The overall pattern of actual right use is similar to the patterns already observed for the cooling ponds and the wet cooling tower: rights purchased for delivery between April and July go uncalled for most years, while rights purchased to deliver water from August thru October are completely called-out in most years.

II 30% DRY-70% WET COOLING TOWER

Table 5.23 presents the monthly net power output and water consumption rates for the heuristic operating policy for this dry-wet cooling system. Referring back to Figure 3.10 in Chapter 3 we note this is a fairly conservative policy in terms of overall water use, and is similar in this respect to the heuristic policy selected for the 40% dry 60% wet cooling tower.

TABLE 5.23 HEURISTIC OPERATING POLICY FOR THE 30% DRY-
70% WET COOLING TOWER

MONTH	EVAPORATIVE LOSS (cfs)	NET POWER OUTPUT (MW _e)
JAN	.7	800.1
FEB	1.2	797.9
MAR	2.0	797.1
APR	4.6	797.0
MAY	6.5	795.1
JUN	7.0	792.9
JUL	7.3	790.9
AUG	7.0	791.3
SEP	6.2	793.6
OCT	4.3	794.2
NOV	2.8	797.0
DEC	1.6	797.6

Tables 5.24 and 5.25 show how the firm may tradeoff reservoir storage for irrigation water right purchases for the single and dual generating unit scenarios, respectively. For either of these scenarios the most critical months for water supply continue to come between August to October, while the least critical months are from April to June.

The OLC algorithm gives a noticeable reduction in the heuristic policy's operating cost under the single generating unit scenario, and a modest reduction under the dual generating unit scenario. Under the former, operating costs are reduced, on average, by \$.6 million per year for all combinations of reservoir storage and irrigation water right purchases, while the average make-up water consumption increases from 4.3 cfs under the heuristic policy to 5.1 cfs. Under the dual unit scenario operating costs are reduced, on average for all combinations of reservoir capacities and right purchases, by \$.4 million per year, and the average make-up water consumption is increased slightly to 4.8 cfs. Figure 5.7 compares the monthly make-up water consumption rates for the OLC and the heuristic policies under the single and dual unit scenarios. In both cases we observe that most of the improvement in operating costs with the OLC algorithm comes through a greater use of the wet towers during the Fall and Winter. In these seasons water is abundant relative to the make-up demand in the dry-wet towers.

Tables 5.26 and 5.27 present the frequencies with which the plant will call out its purchased water rights (from Tables 5.23 and 5.24) when operating with the OLC algorithm for the single and dual unit scenarios, respectively.

TABLE 5.24 NON-INFERIOR COMBINATIONS OF RESERVOIR STORAGE AND IRRIGATION WATER RIGHT PURCHASES FOR THE 30% DRY-WET COOLING TOWER: SINGLE UNIT SCENARIO

AREA (ac)	DEPTH (ft)	WATER RIGHT PURCHASES (CFS)							TOTAL (acre-feet)
		APR	MAY	JUN	JUL	AUG	SEP	OCT	
10	10	1	6	5	8	7	6	4	2145
60	15	0	0	0	8	8	5	4	1430
109.1	25	0	0	0	0	0	0	0	0

TABLE 5.25 NON-INFERIOR COMBINATIONS OF RESERVOIR STORAGE AND IRRIGATION WATER RIGHT PURCHASES (PER UNIT) FOR THE 30% DRY-WET COOLING TOWER: DUAL UNIT SCENARIO

AREA (ac)	DEPTH (ft)	WATER RIGHT PURCHASES (CFS)								TOTAL (acre-feet)
		APR	MAY	JUN	JUL	AUG	SEP	OCT		
30	15	5	12	10	12	12	8	4	3750	
50	20	0	0	6	6	4	3	4	1870	
90	25	0	0	0	0	4	3	4	630	
142.8	25	0	0	0	0	0	0	0	0	

FIGURE 5.7 MONTHLY MAKE-UP WATER CONSUMPTION FOR THE 30% DRY-WET COOLING TOWER UNDER THE HEURISTIC AND OLC OPERATING POLICIES

TABLE 5.26   FREQUENCIES WITH WHICH THE PLANT WILL CALL OUT
PURCHASED IRRIGATION WATER RIGHTS FOR THE 30%
DRY-WET COOLING TOWER: SINGLE UNIT SCENARIO

ACTIVE RESERVOIR STORAGE CAPACITY: 10 ACRES BY 10 FEET
TOTAL IRRIGATION WATER RIGHT PURCHASES: 2145 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
APR	1	1.0						
MAY	6	.91	.0	.0	.09			
JUN	5	.86	.0	.14				
JUL	8	.72	.01	.03	.09	.15		
AUG	7	.18	.04	.09	.69			
SEP	6	.27	.06	.04	.63			
OCT	4	.77	.05	.18				

ACTIVE RESERVOIR STORAGE CAPACITY: 60 ACRES BY 15 FEET
TOTAL IRRIGATION WATER RIGHT PURCHASES: 1430 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
JUL	8	.72	.0	.03	.10	.15		
AUG	8	.18	.04	.08	.52	.18		
SEP	5	.27	.06	.67				
OCT	4	.77	.05	.18				

TABLE 5.27   FREQUENCIES WITH WHICH THE PLANT WILL CALL OUT
PURCHASED IRRIGATION WATER RIGHTS FOR THE 30%
DRY-WET COOLING POWER: DUAL UNIT SCENARIO

ACTIVE RESERVOIR CAPACITY (PER UNIT): 30 ACRES BY 15 FEET
TOTAL IRRIGATION WATER RIGHT PURCHASES (PER UNIT): 3750 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
APR	5	.85	.04	.11				
MAY	12	.90	.0	.01	.0	.01	.0	.08
JUN	10	.86	.0	.0	.01	.0	.13	
JUL	12	.67	.04	.03	.02	.05	.0	.19
AUG	12	.08	.06	.08	.15	.15	.0	.48
SEP	8	.22	.09	.18	.23	.28		
OCT	4	.62	.15	.23				

TABLE 5.27   FREQUENCIES WITH WHICH THE PLANT WILL CALL OUT
PURCHASED IRRIGATION WATER RIGHTS FOR THE 30%
DRY-WET COOLING POWER: DUAL UNIT SCENARIO

ACTIVE RESERVOIR CAPACITY (PER UNIT): 50 ACRES BY 20 FEET
TOTAL IRRIGATION WATER RIGHT PURCHASES (PER UNIT): 1870 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
JUN	6	.86	.0	.0	.14			
JUL	6	.67	.04	.03	.26			
AUG	4	.08	.05	.87				
SEP	3	.16	.84					
OCT	4	.28	.05	.67				

TABLE 5.27   FREQUENCIES WITH WHICH THE PLANT WILL CALL OUT
PURCHASED IRRIGATION WATER RIGHTS FOR THE 30%
DRY-WET COOLING POWER: DUAL UNIT SCENARIO

ACTIVE RESERVOIR CAPACITY (PER UNIT): 90 ACRES BY 25 FEET
TOTAL IRRIGATION WATER RIGHT PURCHASES (PER UNIT): 630 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF USE (IN INCREMENTS OF 2 CFS)					
		0	2	4	6	8	10 12
AUG	4	.05	.0	.95			
SEP	3	.14	.86				
OCT	4	.24	.05	.71			

III DRY TOWER-COOLING POND

Table 5.28 presents the monthly net power output and water consumption rates for the heuristic operating policy for the 50% dry-50% cooling pond system. As with the heuristic policies selected for the other two dry-wet cooling systems this is a conservative policy, with little operation of the cooling pond during the Fall and Winter. However, the cooling pond is used to the greatest extent possible between May and August. The minimum expected output occurs in July when the plant produces 786 MWe.

Tables 5.29 and 5.30 show how the firm may trade off storage for irrigation water right purchases for the single and dual generating scenarios, respectively. For both of these scenarios the most critical months for water are in August thru October, while the least critical are from April to June. Water consumption during the month of October is relatively small under this policy, and so while the firm will prefer to have some October rights on hand the actual number of purchases will be only a fraction of the total number available on the river.

The OLC algorithm gives a modest improvement in the operating costs obtained with the heuristic policy for either of the two plant capacity scenarios. Under the single unit case operating costs are reduced, on average, by \$.41 million per year. Under the two unit case operating costs are reduced by only \$.35 million per year. Figure 5.8 illustrates the comparison between the monthly water consumption rates under the OLC and the heuristic policies for the two capacity scenarios.

TABLE 5.28 HEURISTIC OPERATING POLICY FOR THE 50% DRY
TOWER-50% COOLING POND

MONTH	EVAPORATIVE LOSS (cfs)	NET POWER OUTPUT (MW _e)
JAN	.1	802.9
FEB	.2	803.5
MAR	.8	802.9
APR	5.6	800.4
MAY	7.6	794.1
JUN	8.2	789.6
JUL	9.4	786.1
AUG	8.0	788.5
SEP	6.1	792.1
OCT	1.1	795.1
NOV	.2	800.5
DEC	.1	805.6

FIGURE 5.8 MONTHLY MAKE-UP WATER CONSUMPTION FOR THE DRY TOWER-COOLING POND UNDER THE HEURISTIC AND OLC OPERATING POLICIES

TABLE 5.29

NON-INFERIOR COMBINATIONS OF RESERVOIR STORAGE AND
IRRIGATION WATER RIGHT PURCHASES FOR THE DRY TOWER-
COOLING POND: SINGLE UNIT SCENARIO

AREA (ac)	DEPTH (ft)	WATER RIGHT PURCHASES (CFS)								TOTAL (acre-feet)
		APR	MAY	JUN	JUL	AUG	SEP	OCT		
275	3	0	0	3	9	7	6	1	1490	
275	5	0	0	0	2	8	6	1	955	
275	7	0	0	0	0	0	6	1	420	
275	10	0	0	0	0	0	0	0	0	

TABLE 5.30

NON-INFERIOR COMBINATIONS OF RESERVOIR STORAGE AND
IRRIGATION WATER RIGHT PURCHASES (PER UNIT) FOR THE
DRY TOWER-COOLING POND: DUAL UNIT SCENARIO

AREA (ac)	DEPTH (ft)	WATER RIGHT PURCHASES (CFS)								TOTAL (acre-feet)
		APR	MAY	JUN	JUL	AUG	SEP	OCT		
275	3	0	4	8	7	4	3	1	1600	
275	5	0	0	3	6	4	3	1	1000	
275	7	0	0	0	0	4	3	2	500	
275	11	0	0	0	0	0	0	0	0	

TABLE 5.31 FREQUENCIES WITH WHICH THE PLANT WILL CALL
OUT PURCHASED IRRIGATION WATER RIGHTS FOR THE
50% DRY-50% COOLING POND: SINGLE GENERATING
UNIT SCENARIO

ACTIVE RESERVOIR STORAGE CAPACITY: 275 ACRES BY 3 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED: 1490 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
JUN	3	.83	.17					
JUL	9	.72	.0	.0	.06	.22		
AUG	7	.11	.06	.06	.77			
SEP	6	.22	.0	.11	.67			
OCT	1	1.0						

ACTIVE RESERVOIR STORAGE CAPACITY: 275 ACRES BY 5 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED: 955 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
JUL	2	.68	.23					
AUG	8	.11	.06	.06	.06	.69		
SEP	6	.22	.06	.06	.64			
OCT	1	1.0						

TABLE 5.31 (cont) FREQUENCIES WITH WHICH THE PLANT WILL CALL
OUT PURCHASED IRRIGATION WATER RIGHTS FOR THE
50% DRY-50% COOLING POND: SINGLE GENERATING
UNIT SCENARIO

ACTIVE RESERVOIR STORAGE CAPACITY: 275 ACRES BY 7 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED: 420 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)					
		0	2	4	6	8	10 12
SEP	6	.17	.0	.05	.78		
OCT	1	1.0					

TABLE 5.32 FREQUENCIES WITH WHICH THE PLANT WILL CALL
OUT PURCHASED IRRIGATION WATER RIGHTS FOR THE
50% DRY TOWER-50% COOLING POND: DUAL GENERATING
UNIT SCENARIO

ACTIVE RESERVOIR STORAGE CAPACITY (PER UNIT): 275 ACRES BY 3 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED (PER UNIT): 1600 ACRE-Feet

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
MAY	4	.83	.0	.17				
JUN	8	.83	.05	.0	.0	.12		
JUL	7	.61	.05	.0	.34			
AUG	4	.0	.11	.89				
SEP	3	.12	.88					
OCT	1	1.0						

ACTIVE RESERVOIR STORAGE CAPACITY (PER UNIT): 275 ACRES BY 5 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED (PER UNIT): 1000 ACRE-Feet

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)						
		0	2	4	6	8	10	12
JUN	3	.83	.17					
JUL	6	.61	.06	.0	.33			
AUG	4	.0	.11	.89				
SEP	3	.12	.88					
OCT	1	1.0						

TABLE 5.32 (cont) FREQUENCIES WITH WHICH THE PLANT WILL CALL
OUT PURCHASED IRRIGATION WATER RIGHTS FOR THE
50% DRY TOWER-50% COOLING POND: DUAL GENERATING
UNIT SCENARIO

ACTIVE RESERVOIR STORAGE CAPACITY (PER UNIT): 275 ACRES BY 7 FEET
TOTAL IRRIGATION WATER RIGHTS PURCHASED (PER UNIT): 500 ACRE-FEET

MONTH	PURCHASE (cfs)	FREQUENCY OF WATER USE (IN INCREMENTS OF 2 CFS)					
		0	2	4	6	8	10 12
AUG	4	.0	.11	.89			
SEP	3	.12	.88				
OCT	1	1.0					

Tables 5.31 and 5.32 present the frequencies with which the plant will actually call out its purchased water rights (from Tables 5.27 and 5.28) when operating with the release policies from the OLC control for the single and dual unit scenarios, respectively.

5.4 COMPARING THE COOLING SYSTEM ALTERNATIVES

We will now compare the various water management strategies that may be arranged through the selection of one of the six cooling systems by assigning costs to the construction of reservoirs, purchasing irrigation water rights, and adding, in a parametric fashion, costs for make-up water treatment and costs for delivering water to a plant site several miles from the river itself. We are particularly interested in the tradeoffs available between installing reservoirs and/or partial dry cooling and purchasing water rights, and will use these tradeoffs to define the firm's demand for water in general, and for existing water rights in particular. In the process of defining the firm's demand schedule for water we will also be illustrating how the firm's optimal management strategy, from the set of all strategies, can be expressed simply as a function of the cost of water.

We will assume all reservoirs will be diked enclosures located off-stream. The enclosures will be rectangular for the cooling ponds in order to promote efficient cooling and square for the wet and dry-wet cooling towers. The cooling ponds have an internal dike running 70% of the length of the pond, creating two parallel 'channels', to effect a one-dimensional flow. Each channel is 2000' wide, thereby giving every

cooling pond an overall width of 4000'. Figure 3.3 in Chapter 3 illustrates a plan view of a representative cooling pond, while Figure 3.4 presents a general schematic of the dike geometry used for all ponds and reservoirs.

The initial capital cost of constructing off-stream reservoirs for the dry-wet and wet cooling towers is calculated using the following formula:

$$\begin{aligned} \text{CAP} = & A \cdot \theta_{\text{LA}} + \theta_{\text{LI}} [A + 4\sqrt{A} \cdot \sqrt{H^2 + (2.5 H)^2}] \\ & + \theta_{\text{EX}} [4\sqrt{A} [20H + 2.5 H^2]] \end{aligned} \quad (5.4)$$

where:

CAP = The initial capital cost of the reservoir.

θ_{LA} = The unit land purchase and preparation cost (\$/Ft²).

θ_{LI} = The unit lining cost (\$/Ft²).

A = The surface area of the reservoir (Ft²).

H = The total depth of the reservoir (Ft).

θ_{EX} = The unit excavation and diking cost (\$/Ft³).

The second term on the right hand side represents the cost of lining the reservoir bottom and the interior walls of the dikes. Under this formula the firm can capture certain economies of scale by making the reservoir area larger, but will suffer diseconomies of scale by building reservoirs to greater depths. However, the additional surface evaporation from reservoirs with large areas may lead to costs not

included in this formula. As a consequence, a shallow reservoir may or may not be more desirable than a deep reservoir having the same volume.

The initial capital cost for building a cooling pond is calculated using the following formula:

$$\begin{aligned} \text{CAP} = & A \cdot \theta_{LA} + \theta_{LI} [A + \sqrt{H^2 + (2.5H)^2} (4000 + 2.7L)] \\ & + \theta_{EX} [(4000 + 2.7L) (20H + 2.5H^2)] \end{aligned} \quad (5.5)$$

where L is the length of the pond (Ft). As is the case with storage reservoirs for the cooling towers, there are diseconomies of scale associated with deeper cooling ponds. Unlike the former, however, there are no economies of scale for building the ponds with larger surface areas.

The total depth of a cooling pond or a storage reservoir, H, is the sum of the active storage depth, the dead storage depth, and the freeboard depth (Figure 3.4). For this thesis we will assume the freeboard and the dead storage depths are both 5 feet.

The present valued costs of owning and operating a 475 acre cooling pond with different pond storage capacity/irrigation rights purchase alternatives are given in Table 5.33 for the six plant capacity/reservoir cost scenarios. Similar costs for the remaining cooling systems are repeated in Tables 5.34 to 5.38. All costs presented in these tables are exclusive of the costs of purchasing water rights, water treatment and off-river transport costs.

TABLE 5.33   PRESENT VAUED COST OF ALTERNATIVE WATER
MANAGEMENT STRATEGIES WITH THE 475 ACRE
COOLING POND [\$ MILLIONS]

CAPITAL COST [LESS POND]:   25.3
LIFETIME OPERATING COST: 1092.1

ONE UNIT:

RESERVOIR COST	IRRIGATION RIGHTS PURCHASED [AC-FT]			
	3870	2680	1480	0
LOW:	1125.1	1128.6	1132.9	1138.0
MEDIUM:	1142.9	1148.4	1155.2	1163.3
HIGH:	1157.6	1163.4	1170.9	1178.6

TWO UNITS:

RESERVOIR COST	IRRIGATION RIGHTS PURCHASED PER UNIT [AC-FT]				
	2390	1670	1000	420	0
LOW:	1138.0	1143.9	1158.1	1175.6	1196.3
MEDIUM:	1163.3	1172.5	1194.8	1222.1	1254.3
HIGH:	1178.6	1188.1	1210.8	1238.4	1271.1

TABLE 5.34   PRESENT VAULED COST OF ALTERNATIVE WATER
MANAGEMENT STRATEGIES WITH THE 800 ACRE
COOLING POND

CAPITAL COST [LESS POND]:   23.7
LIFETIME OPERATING COST: 1083.6

ONE UNIT:

RESERVOIR COST	IRRIGATION RIGHTS PURCHASED [AC-FT]			
	5060	3280	1610	0
LOW:	1118.5	1122.4	1127.1	1132.6
MEDIUM:	1147.2	1153.5	1160.9	1169.6
HIGH:	1171.9	1178.4	1186.1	1195.0

TWO UNITS:

RESERVOIR COST	IRRIGATION RIGHTS PURCHASED PER UNIT [AC-FT]				
	3750	2560	2090	1130	0
LOW:	1123.9	1137.4	1145.8	1166.2	1141.2
MEDIUM:	1155.9	1177.1	1190.4	1222.4	1261.4
HIGH:	1180.8	1202.6	1216.2	1248.7	1288.4

TABLE 5.35   PRESENT VAULED COST OF ALTERNATIVE WATER
MANAGEMENT STRATEGIES WITH THE 500 FOOT
WET COOLING TOWER [\$ MILLIONS]

CAPITAL COST: 38.1
LIFETIME OPERATING COST: 1091.7

ONE UNIT:

RESERVOIR COST	IRRIGATION RIGHTS PURCHASED [AC-FT]				
	7500	3280	1730	600	0
LOW:	1129.1	1132.0	1140.5	1146.3	1148.0
MEDIUM:	1132.1	1138.1	1154.3	1164.8	1168.7
HIGH:	1133.8	1141.4	1161.0	1173.8	1178.4

TWO UNITS:

RESERVOIR COST	IRRIGATION RIGHTS PURCHASED PER UNIT [AC-FT]				
	2950	1430	1100	390	0
LOW:	1151.8	1160.3	1168.3	1181.1	1189.7
MEDIUM:	1170.2	1186.6	1202.4	1229.4	1248.4
HIGH:	1175.3	1195.1	1215.0	1249.8	1275.0

TABLE 5.36 PRESENT VAULED COST OF ALTERNATIVE WATER
MANAGEMENT STRATEGIES WITH THE 40% DRY-60%
WET COOLING TOWER [\$ MILLIONS]

CAPITAL COST: 110.1
LIFETIME OPERATING COST: 1103.5

ONE UNIT:

RESERVOIR COST	IRRIGATION RIGHTS PURCHASED [AC-FT]			
	1430	1130	600	0
LOW:	1214.7	1216.5	1218.8	1221.6
MEDIUM:	1215.7	1219.1	1223.0	1228.6
HIGH:	1216.1	1220.2	1225.1	1231.2

TWO UNITS:

RESERVOIR COST	IRRIGATION RIGHTS PURCHASED PER UNIT [AC-FT]				
	3750	1220	690	210	0
LOW:	1215.0	1215.7	1217.4	1219.0	1219.6
MEDIUM:	1216.6	1217.8	1221.0	1223.0	1225.4
HIGH:	1217.6	1218.9	1222.7	1225.9	1228.0

TABLE 5.37   PRESENT VAULED COST OF ALTERNATIVE WATER
MANAGEMENT STRATEGIES WITH THE 30% DRY-70%
WET COOLING TOWER [\$ MILLIONS]

CAPITAL COST:	94.4	
LIFETIME OPERATING COST:	1104.2	[ONE UNIT]
	1109.6	[TWO UNITS]

ONE UNIT:

RESERVOIR COST	IRRIGATION RIGHTS PURCHASED [AC-FT]		
	2150	1430	0
LOW:	1200.1	1203.2	1209.3
MEDIUM:	1201.1	1207.4	1218.4
HIGH:	1201.5	1209.5	1222.2

TWO UNITS:

RESERVOIR COST	IRRIGATION RIGHTS PURCHASED PER UNIT [AC-FT]				
	1370	834	630	89	0
LOW:	1207.8	1209.8	1210.7	1211.4	1212.6
MEDIUM:	1211.4	1215.2	1217.1	1218.8	1221.6
HIGH:	1213.1	1217.6	1220.1	1222.5	1226.4

TABLE 5.38   PRESENT VAULED COST OF ALTERNATIVE WATER
MANAGEMENT STRATEGIES WITH THE 50% DRY TOWER
50% COOLING POND

CAPITAL COST [LESS POND]:	103.1	
LIFETIME OPERATING COST:	1109.4	[ONE UNIT]
	1112.0	[TWO UNITS]

ONE UNIT:

RESERVOIR COST	IRRIGATION RIGHTS PURCHASED [AC-FT]			
	1490	960	420	0
LOW:	1217.0	1217.9	1218.8	1220.4
MEDIUM:	1227.3	1228.7	1230.2	1232.8
HIGH:	1235.9	1237.3	1238.9	1241.6

TWO UNITS:

RESERVOIR COST	IRRIGATION RIGHTS PURCHASED PER UNIT [AC-FT]			
	1600	1000	500	0
LOW:	1219.6	1220.5	1221.4	1223.0
MEDIUM:	1230.0	1231.6	1232.8	1235.4
HIGH:	1238.5	1241.0	1241.5	1245.1

Three phenomena affect the cost of installing reservoirs when we go from the single 800 MWe unit scenario to the two unit scenario. The first is a diseconomy of scale effect on the required reservoir capacity: for a fixed number of irrigation rights purchased per generating unit a two-fold increase in plant demand leads to a greater than two-fold increase in the reservoir capacity required by the plant. In the water resource literature this is also known as the 'storage-yield' effect. For a fixed water supply the relationship between water demand, D , and the reservoir capacity, V , required to support this demand at a given level of reliability has the general form:

$$V \approx A \cdot D^B \quad (5.5)$$

where $A > 0$ and $B > 1.0$

The second phenomena is the diseconomy of scale effect found with greater storage depths which affects the cost of installing storage reservoirs for all cooling systems. The third factor is the economy of scale effect found with the reservoir surface area and which affects the cost of installing storage for wet and dry-wet cooling towers only. For almost every cooling system the two dis-economies of scale effects predominate. Interestingly enough, however, the economies of scale effect is the predominant one for the 40% dry-60% wet cooling towers when the firm purchases few irrigation rights. As a consequence the per-unit cost for this system will actually decrease when the firm expands the plant capacity from one unit to two.

5.5 THE FIRM'S DEMAND FOR IRRIGATION RIGHTS

The results presented in Tables 5.33 to 5.38 represent, from the cooling system design standpoint, tradeoffs between total cooling system cost [including the cost of storage] and irrigation right purchases for each of the six plant capacity/reservoir cost scenarios. For any one scenario these tradeoffs give us a set of isoquants, one for each cooling system, defining feasible substitutions between installing storage and purchasing irrigation water that will allow each generating unit to meet an expected demand of 800 MWe. For each scenario the six separate cooling system isoquants may in turn be integrated to yield a single non-inferior production isoquant lying below and to the left of all the others. The firm's demand curve for purchasing irrigation rights under any one scenario may be derived by inspecting the slope anywhere along the non-inferior isoquant for that scenario.

Figure 5.9 illustrates the six separate cooling system isoquants for the single unit/low reservoir cost scenario; the non-inferior isoquant is the envelope of the separate isoquants lying in the southwest corner of the illustration. Figure 5.10 illustrates the derived demand schedule for irrigation rights as a function of the annual cost per right (\$/ac-ft/yr) under this scenario. We find the firm should purchase all the outstanding irrigation rights below the site on this creek when the annualized cost of a right (including both the purchase and transaction costs to the firm) is less than \$110/ac-ft. When the total annualized cost lies between \$110 and \$150 per acre-foot the firm should purchase rights entitling it to 5000 acre-feet per year. The

firm should purchase no rights, however, when the effective annualized cost exceeds \$175/ac-ft. This particular demand curve is clearly only an approximation to the 'true' demand curve, the accuracy of the approximation being limited by the number of points we have examined on the non-inferior production isoquant. Under this scenario the non-inferior isoquant is defined wholly by the single isoquant for the 800 acre cooling pond. This being the case we can return to Tables 5.7 and 5.34 and identify the effective opportunity value to the firm for certain irrigation right purchases. From Table 5.7 we find that the value of \$175/ac-ft/yr corresponds with the firm's purchase of rights to 240 acre-feet in July, 390 acre-feet in August, 540 acre-feet in September, and 480 acre-feet in October. We could further differentiate the opportunity value of these rights by selecting a finer interval of reservoir sizes when running the reservoir simulation algorithm from Chapter 3.

Figures 5.11 thru 5.20 illustrate the feasible production isoquants between total cooling system cost and irrigation rights acquired by the firm, and the derived demand curves for the other five plant capacity/reservoir cost scenarios. The non-inferior isoquants for these scenarios are non-convex, in contrast to the non-inferior isoquant observed for the single unit/low reservoir cost scenario.

The non-inferior production isoquants for the six plant capacity/reservoir cost scenarios represent the effect of two processes that may act singly or in combination. The first is simply the substitution of reservoir storage for irrigation right purchases, and is

FIGURE 5.9 PRESENT VALUED COST OF COOLING SYTEM PLUS STORAGE
VERSUS QUANTITY OF IRRIGATION WATER RIGHTS

FIGURE 5.10 THE ENERGY FIRM'S DEMAND SCHEDULE
FOR IRRIGATION WATER RIGHTS

FIGURE 5.11 PRESENT VALUED COST OF COOLING SYSTEMS PLUS STORAGE
VERSUS QUANTITY OF IRRIGATION WATER RIGHTS

FIGURE 5.12 THE ENERGY FIRM'S DEMAND SCHEDULE
FOR IRRIGATION WATER RIGHTS

FIGURE 5.13 PRESENT VALUED COST OF COOLING SYSTEMS PLUS STORAGE
VERSUS QUANTITY OF IRRIGATION WATER RIGHTS

FIGURE 5.14 THE ENERGY FIRM'S DEMAND SCHEDULE
FOR IRRIGATION WATER RIGHTS

FIGURE 5.15 PRESENT VALUED COST OF COOLING SYSTEMS PLUS STORAGE
VERSUS QUANTITY OF IRRIGATION WATER RIGHTS

FIGURE 5.16 THE ENERGY FIRM'S DEMAND SCHEDULE
FOR IRRIGATION WATER RIGHTS

FIGURE 5.17 PRESENT VALUED COST OF COOLING SYSTEMS PLUS STORAGE
VERSUS QUANTITY OF IRRIGATION WATER RIGHTS

FIGURE 5.18 THE ENERGY FIRM'S DEMAND SCHEDULE
FOR IRRIGATION WATER RIGHTS

FIGURE 5.19 PRESENT VALUED COST OF COOLING SYSTEMS PLUS STORAGE
VERSUS QUANTITY OF IRRIGATION WATER RIGHTS

FIGURE 5.20 THE ENERGY FIRM'S DEMAND SCHEDULE
FOR IRRIGATION WATER RIGHTS

observed along any portion of a non-inferior isoquant corresponding to one of the individual cooling system isoquants. The convex portions of a non-inferior isoquant are created by this type of substitution. The second effect is also a substitution effect, but represents the substitution of both the cooling system and reservoir capacity for purchases of water rights. In the case study this effect always leads to non-convex portions on a non-inferior isoquant. In the discussions to follow we shall refer to the first effect as a 'Type I' substitution and the second as a Type II' substitution. Referring to Figures 5.9 thru 5.14 we find that Type I substitutions are responsible for the shape of the non-inferior isoquants for the single unit/low reservoir cost and the single unit/high reservoir cost scenarios. Both Type I and Type II substitutions appear on the isoquant for the single unit/medium reservoir cost scenario. On the whole, Type I substitutions appear to have the dominant influence on the non-inferior production isoquants for the single unit scenario.

When the principal alternative to acquiring water rights is to install larger reservoir volumes the firm's demand schedule for water rights will shift up with higher reservoir costs. In order for a point 'i' on the isoquant to be the optimal point the following equilibrium must occur:

$$\text{MRS}_{\text{SR}}(i) = - \frac{P_R}{P_S}$$

where:

$\text{MRS}_{\text{SR}}(i)$ = The marginal rate of substitution of storage for right

purchases physically feasible at point 'i'

P_R = The price for water rights

P_S = The effective price for storage

Since $MRS_{SR}(i)$ is a constant at point 'i', P_R must increase at the same rate as P_S . We do, in fact, observe this in the upward shifts in the firm's demand schedule for water in response to higher reservoir costs.

Under the two unit scenario Type I substitution tends to dominate only where large purchases of irrigation rights are made. Type II substitution, on the other hand, is dominant at those alternatives where the firm acquires few water rights. For the medium and high reservoir costs Type II substitutions represent shifts from installing cooling ponds to installing dry-wet cooling towers. With Type II substitution the firm can reduce purchases of water rights by switching to a different cooling system and away from a heavy dependence on the need to install larger reservoir capacities. For this reason we find that the firm's demand curves for irrigation water rights shift down as reservoir costs increase.

We note that non-convex production isoquants lead to irrigation water demand schedules that have jumps, or 'steps', at discrete intervals. This means that a demand curve can be infinitely elastic over broad intervals of irrigation water right purchase alternatives, and become perfectly inelastic at those points where the jumps occur.

For the four medium and high reservoir cost scenarios the non-convex portions of the non-inferior production isoquants separate strategies where no irrigation rights are purchased from strategies where a relatively substantial number of rights (3500 acre-feet, total, for both plant capacity scenarios) are purchased. That is, for each of these four scenarios there is a critical water right price above which the firm should not purchase any irrigation water rights and below which the firm should purchase a substantial number of rights.

This leads to a rather interesting implication for the plant designer. We might expect in many cases that there will be some 'entrance' costs for a firm wishing to enter the water rights market as a buyer. There is a certain overhead involved in purchasing water rights in the West. This includes hiring consultants to estimate the probable yields of various water right prospects, and arranging hearings before local water administrators to demonstrate that all provisions for non-injury and beneficial use will be met. This 'overhead' cost may well be the same whether the firm purchases 100 rights or 1000 rights. Intuitively, if the firm is prepared to make the investment needed to purchase a small block of rights it might well capture greater benefits if it purchases a larger number of rights instead. The four water right demand curves in Figures 5.12, 5.14, 5.18, and 5.20 show that this strategy is complemented by the economics of designing cooling systems and storage reservoirs. From the cooling system design standpoint the firm should purchase no irrigation rights when the effective cost is above a certain threshold, and purchase, at the minimum, a relatively large number of rights when the effective cost per right is below this

threshold.

One notable observation that can be made for the six separate irrigation water right demand curves presented here is the tremendous difference between the energy firm's willingness to pay for rights delivered in Summer versus rights delivered during the Spring. In almost every case total purchases of less than 3000 acre-feet of irrigation water come from rights that deliver between June and October. Purchases in excess of 3000 acre-feet of water include rights that deliver during April and May as well. As a general rule we find that the firm's willingness to pay, on a per acre-foot basis, for water rights in excess of 3000 acre-feet will be roughly one-third to one-fifth of its willingness to pay for access to the first 3000 acre-feet of rights. This implies that water delivered in Spring is at most between one-third to one-fifth as valuable as rights to water delivered during the Summer. Moreover, we noted in the previous section that under the single unit scenario the firm need only infrequently call out its Spring rights. At the very least one alternative to purchasing Spring water rights is to build, at a relatively moderate cost, larger storage reservoirs. Under the single unit scenario the firm might consider the additional option whereby it rents certain water rights from the downstream irrigators during severe droughts. In this manner it avoids altogether the cost of either having to build large reservoirs, or having to purchase irrigation water outright.

Neither the cost of treating the cooling system make-up water nor the cost of transporting this water to an offstream plant will change the

shape of the individual cooling system isoquants we have observed for the six plant capacity/reservoir cost scenarios. These two additional costs will, however, shift the relative positions of these curves with respect to each other, and thus change the shape of the non-inferior production isoquants. Put another way, the costs of treating and transporting cooling system make-up water will show up wholly through Type II substitutions. We will assume water treatment costs \$0.30/1000 gal. of make-up water; a relatively high cost suggested by Probst and Gold (1977). In this thesis transport costs are linear with respect to the pumping distance and nonlinear (concave) with respect to the average make-up water demand. The coefficients used to calculate transport costs for the six cooling systems were presented earlier in Table 5.5 The coefficients for the dry-wet cooling systems are calculated using the average water consumption rates realized with the optimal operating policies.

Treatment and transport costs will favor hybrid dry-wet cooling systems over the fully 'wet' cooling ponds and cooling towers, the cooling system make-up water demands for the cooling ponds and the wet cooling towers being quite similar. It is not surprising then that the production isoquants for all three reservoir cost alternatives under the single 800 MWe unit scenario are relatively insensitive to treatment and transport costs. To see this we may ask: how far would a plant have to pump water from a river before dry-wet cooling systems appear on the production isoquants? For the low reservoir cost scenario the distance would have to be approximately 125 miles without treatment costs accounted for, and 110 miles with treatment costs added in. For the

medium reservoir cost scenario the transport distances must be 110 and 90 miles, respectively, and for the high reservoir cost scenario the distances must be 105 and 80 miles, respectively.

By contrast, the production isoquants observed for the case where two generating units are installed are highly sensitive to the costs of treatment and transport, and this sensitivity shows up quite clearly in the firm's demand curves for irrigation water rights. The dry-wet cooling systems already appear on the production isoquants for the medium and high reservoir cost scenarios when treatment and transport costs are not accounted for; the firm's demand curve for water rights will be shifted down at all levels of treatment and delivery costs. For the low reservoir cost scenario the dry-wet cooling systems will appear on the non-inferior production isoquant when the firm must deliver water over a distance of 50 miles when treatment costs are not included, and 25 miles when treatment costs are accounted for.

Figure 5.21 shows the firm's demand schedule for irrigation water rights for transport distances of 30 and 60 miles, with and without treatment costs accounted for, for the high plant capacity/low reservoir cost scenario. By comparison with Figure 5.10 we find there is little change in the firm's demand schedule for irrigation rights when the transport distance is 30 miles or less. For a transport distance of 60 miles, however, the demand curves show a noticeable shift downward, particularly when treatment costs are accounted for. We find the marginal value of the first 1000 acre-feet to the firm drops from an average value of \$1600/ac-ft/yr when the plant is on the river to

FIGURE 5.21 THE FIRM'S DEMAND SCHEDULE FOR IRRIGATION WATER RIGHTS
WITH TREATMENT AND TRANSPORT COSTS ACCOUNTED FOR
TWO GENERATING UNITS
LOW RESERVOIR COST SCENARIO

———— : WITHOUT TREATMENT COSTS
----- : WITH TREATMENT COSTS

\$960/ac-ft/yr and \$650/ac-ft/yr without and with treatment costs accounted for, respectively.

Figure 5.22 illustrates how the firm's demand for irrigation rights will shift downward for plant sites 10, 30, and 60 miles away from the river for the medium reservoir cost scenario. At every distance water treatment costs reduce the marginal value of the first 1000 acre-feet to the firm by roughly \$300 per acre-foot per year. For a plant site 60 miles from the river the critical price above which the firm should not purchase water rights falls from \$1500/ac-ft/yr for a site on the river, to \$600/ac-ft/yr (a factor of 2.5) when treatment costs are not accounted for, and \$400/ac-ft/yr (by a factor of almost 4) when the costs of make-up water treatment are included in the analysis.

Figure 5.23 repeats similar results for the high reservoir cost scenario. Again, the firm's demand for irrigation rights takes a dramatic shift downward when water must be transported to the plant site. For a transport distance of 60 miles, in fact, the 30% dry-70% wet cooling tower is the preferred system at all irrigation purchase possibilities when we account for the cost of water treatment in the comparison of the cooling systems.

FIGURE 5.22 THE FIRM'S DEMAND SCHEDULE FOR IRRIGATION WATER RIGHTS WITH TREATMENT AND TRANSPORT COSTS ACCOUNTED FOR

TWO GENERATING UNITS
MEDIUM RESERVOIR COST SCENARIO

— : WITHOUT TREATMENT COSTS
- - : WITH TREATMENT COSTS

FIGURE 5.23 THE FIRM'S DEMAND SCHEDULE FOR IRRIGATION WATER RIGHTS WITH TREATMENT AND TRANSPORT COSTS ACCOUNTED FOR

TWO GENERATING UNITS

HIGH RESERVOIR COST SCENARIO

— : WITHOUT TREATMENT COSTS
 - - - : WITH TREATMENT COSTS

5.6 THE FIRM'S DEMAND FOR OVERALL WATER CONSUMPTION

For this case study there is an inverse relationship between the firm's demand schedule for overall water consumption and four factors: a) the number of plants installed on the river; b) the cost of installing reservoir storage; c) the cost of treating make-up water and/or transporting it to an off-stream site; and d) the effective cost of acquiring existing water rights. An increase in any one of these factors will make water consumption appear less attractive than before, causing the demand schedule for overall consumption to shift down.

We will illustrate the firm's demand schedule for overall water consumption for each plant capacity/reservoir cost scenario for the case where the firm purchases no irrigation rights and neither treats nor transports its make-up water. We will measure overall consumption as the sum of the direct evaporation from the cooling system plus the surface evaporation from the make-up water reservoir. From the view of measuring the opportunity cost for using water in energy it should not matter whether water is lost in the cooling system or through reservoir evaporation.

Figure 5.24 illustrates the firm's demand schedule for overall water consumption for the three reservoir cost possibilities under the single unit scenario. Figure 5.25 illustrates this demand schedule for the dual generating unit scenario. These schedules are only approximate since we often have only two or three points to draw a line through; we cannot assume the true curves would appear as stepped or block-like as

FIGURE 5.24 THE ENERGY FIRM'S DEMAND SCHEDULE
FOR OVERALL WATER CONSUMPTION

FIGURE 5.25 THE ENERGY FIRM'S DEMAND SCHEDULE
FOR OVERALL WATER CONSUMPTION

they are drawn here. Nevertheless these curves afford us a glimpse into the firm's demand for overall water consumption. As predicted above, the demand schedules shift down with higher reservoir costs and a higher number of plants on the river. In the first case higher reservoir costs penalize cooling systems that require large reservoirs to support high rates of water use, particularly during the Summer. In the latter case the 'storage-yield' effect on the reservoir capacity needed to support a given level of water demand creates a diseconomies of scale which in turn penalizes high rates of water use.

It is important to keep in mind that each of these demand functions shows a single slice of the complete functions giving the firm's demand for overall consumption. Were we to include the costs of either treating and/or transporting the water these curves would shift downward. Conversely, were we to allow the plant to purchase some amount of existing water rights these curves would shift upward. It is interesting to note that the firm's willingness to pay for overall water consumption in this case study can be over an order of magnitude less than other estimates found in the literature. Hu and Engleson (1977) suggest make-up water must cost \$1200/ac-ft/year for a utility to switch from wet cooling to dry-wet cooling for steam-electric power generation. Choi and Glicksman (1978) suggest water must cost in the neighborhood of \$2000/ac-ft/year before a utility will make this substitution.

5.7 SUMMARY

At the beginning of this chapter three questions were posed with respect to the problem of balancing the numerous choices involved in designing a water management strategy for a western energy facility. These questions were:

- 1) Can the choices be quantified?
- 2) Can the choices and decisions be ranked in terms of their probable effect on the synthesis of a management strategy?
- 3) How might we integrate the many choices into a smaller set of strategies which may, in turn, be examined in greater detail?

We now ask: have we made progress in answering any or all of these questions?

The hypothetical case study in this chapter has demonstrated how the simulation and operations models developed in Chapters 3 and 4 allow us to quantify the choices (question 1). We have selected three separate measurements to quantify the choices: the present valued cost of the plant and equipment (including the cooling system and reservoir), the number of water rights purchased, and the total annual cooling system water consumption. In addition we have seen how the operations and simulation models from Chapter 4 may be used to quantify the firm's implicit preference for water rights delivered in the Summer over water delivered in the Spring. We have also used the models to distinguish

between the purchase and the actual use of a right.

We have seen how one may integrate the many possible choices among cooling system designs, reservoir capacities, water right purchases, and overall water consumption into a smaller set of production isoquants which are represented in terms of the three separate measures (question 3). The firm's preferred position on any isoquant, and hence the firm's preferred water management strategy, may be determined by assigning unit costs to the purchase of existing water rights and to overall water consumption.

This case study has illustrated the utility of employing the models developed in this thesis for two purposes: 1) to help designers to identify good water management strategies for an energy facility, and 2) to identify an energy firm's willingness to pay for different sources of water. We may inquire whether the results found for this case study might be replicated elsewhere and thus serve as initial observations about water use for energy production. We will now see why we might answer this in the affirmative (question 2).

There are a number of results that appear due to site features that are likely to be found elsewhere. These include: 1) the finding that an energy firm will have a higher willingness to pay for water delivered during the middle and late Summer than during the Spring and early Summer; and 2) the finding that an energy firm might afford to leave rights specifically purchased for delivery during Spring and early Summer uncalled in most years. On many unregulated western rivers large

amounts of unappropriated water are frequently available during the Winter and Spring months even though the entire streamflows during the Summer may be fully appropriated. An energy firm will tend to place a low marginal value on water delivered during the Spring if ample supplies of 'surplus' water appear regularly during this period. By contrast, a firm's willingness to pay for water rights delivered in the late Summer, when water is scarce, is equal to the foregone cost of not having to build a larger reservoir to supply the plant with water during this period.

Because water rights purchased for Spring delivery may not be called out by the firm in most years, it might consider renting water rights for Spring deliveries only during dry years. Under the single unit scenario the firm will demand Spring water only when relatively small reservoirs are built (Figures 5.10, 5.12, and 5.14). The firm's willingness to pay for this water averages \$100/ac-ft/yr. However, we find from Tables 5.11 and 5.16 that Spring water rights may go completely uncalled anywhere from 6 to 9 years out of every 10. Thus rental prices under these conditions could be anywhere from \$250/ac-ft/yr to \$1000/ac-ft/yr before the outright purchase of Spring rights would appear more attractive than intermittent rentals. These prices are several times higher than the short run marginal value of water for typical western irrigation at the beginning of a relatively dry irrigation season. This suggests that farmers could have an economic incentive to withdraw land from production during low flow years and rent their water to the energy firm for the duration of the irrigation season.

The finding that an energy firm can have a non-convex production isoquant with respect to the tradeoffs between water right purchases and total cooling system/reservoir cost appears to be a general finding. This finding is not so much dependent on certain features of a site as it is simply on the availability of alternative cooling system designs to choose from. As long as the options include two or more different cooling systems designs there is always the likelihood that the non-inferior isoquant will be non-convex. We noted before that this is due to the effect of Type II substitutions. In this case study non-convex isoquants frequently separate a water management strategy calling for the firm to purchase no existing water rights from a strategy calling for the firm to purchase a large block of rights. We have already noted that this has important implications for a firm when there are high 'entrance' costs simply to enter as a buyer in the water rights market.

Finally, there are a number of findings that are somewhat specific for this case study, but may be replicated at other sites. One interesting finding is that there is a difference between the firm's willingness to pay for overall water consumption in general and its willingness to pay for existing rights in particular. For instance, the firm's demand schedule for overall water consumption will always shift down with increases in the cost of installing a reservoir. It's demand schedule for irrigation rights, on the other hand, will shift up with increases in reservoir costs when Type I substitutions dominate the non-inferior production isoquant and shift down when Type II substitutions dominate. This difference occurs because surplus flows are available for appropriation; overall water consumption is not necessarily

synonymous with consumption of existing rights. This is especially true when surplus flows can be captured at a moderate cost with storage reservoirs. Under this condition surplus water and reservoirs are readily substituted for existing rights, and the benefits to consuming water (improved plant operating efficiency) greatly outweigh its costs (constructing a reservoir). The situation is reversed when surplus water is no longer plentiful (e.g. when a number of energy facilities are built on the river). Under this condition the energy firm has a greater incentive to purchase existing water rights. At the same time the costs incurred to support high levels of water consumption may approach or even exceed the benefits of its use. The firm now has a greater incentive to conserve overall water use through a change in the cooling system design.

This situation where 'surplus' flows are available for consumption is not unique to Crazy Woman Creek, but is found elsewhere in the West (Anderson, 1975; Colorado Dept. of Natural Resources, 1980).

Can we make the argument that this methodology promotes a better understanding of the tradeoffs involving water use for energy than can be realized with many of the other approaches found in the literature? We will answer this in the affirmative.

One frequently adopted method for assessing water use tradeoffs in the western U.S. is to examine the problem from a regional perspective. That is, these tradeoffs are analyzed in terms of gross water use in various activities over an entire river basin or state. 'Optimal' water

allocations among the many activities are frequently sought through some optimization model where the objective function is a measure of the minimum total cost (or maximum total benefit) for all users in the region.

In order that the solution to the regional model be kept within practical computational bounds, a crucial assumption is invariably employed: water availability is measured either on an annual average basis or some 'safe-yield' basis (Bishop, et al., 1975; Bishop and Naryanan, 1978; Buras, 1979; Flug, 1979; Lall and Mays, 1980). Let us see how our analysis would have changed were we to have used only average annual streamflows to measure water availability in our case study.

The average annual flow past the plant site for the 18 years of record was 37 cfs. Our estimates of downstream agricultural demand suggest the average potential use is approximately 10.5 cfs. However, the potential demand cannot be met in every year, and the actual average use is actually closer to 7 cfs. Thus, depending on how downstream demands are accounted for the surplus flows remaining for energy appear to be between 26.5 and 30 cfs.

Were we to use these average estimates in our assessment of alternative cooling system designs we could conclude there is sufficient surplus water remaining in the river to support fully wet cooling towers under either of the two plant capacity scenarios without having to construct any new reservoirs.

The methodology adopted in this thesis, however, reveals an altogether different story. While there is enough water to meet energy demands without reducing existing irrigation activity, this cannot be done without installing some back-up reservoir capacity as well. Consequently, there will always be some incentive for the energy firm to try to reduce reservoir costs by purchasing irrigation water. This incentive is particularly strong under any of the scenarios where two 800 MWe units are installed at the plant. Were a regional model to have been used by, say, state water authorities to anticipate potential water right transfers from agriculture to energy there can be little doubt such a model would have seriously underestimated the incentives for energy firms to purchase existing rights.

Another frequently adopted method for assessing water use tradeoffs is to incorporate the stochastic behavior of streamflows in a river basin simulation model, but assume the demand for water in energy is inelastic (Northern Great Plains Research Program, 1974; Colorado Dept. of Natural Resources, 1980; Boris and Krutilla, 1980). This approach has been used in select river basins to estimate the total reservoir storage capacity needed to support specified levels of water use in different activities on a single river. Each of the studies cited above assumed that all cooling would be done with fully wet cooling towers.

Returning to Figures 5.11 and 5.13, we find this assumption leads to roughly the same results reached with our methodology under two of the three reservoir cost scenarios for a single 800 MWe unit installed at the plant. However, for all scenarios where two units are installed our

methodology suggests there is a strong preference for installing either cooling ponds or dry-wet cooling towers over fully wet cooling towers. Were we to have limited our cooling system design options to only fully wet cooling towers, we would have concluded that the firm's willingness to pay for irrigation water is much higher than it actually is.

It seems fair to conclude that the use of average annual flows to measure water availability will tend to underestimate an energy firm's willingness to pay for certain types of water (e.g., irrigation water rights). This bias occurs because Type I substitutions between purchasing water rights and reservoir storage are not revealed. By the same token, an approach which assumes the demand for water in energy is inelastic cannot, by definition, capture Type II substitutions. For this reason such an approach will tend to overestimate an energy firm's true willingness to pay for supplemental water rights. The initial results for the case study suggest, however, that the methodology presented in this thesis shares neither of these two shortcomings due to the fact it can account for both types of substitution simultaneously.

CHAPTER 6 SUMMARY, CONCLUSIONS, AND FUTURE RESEARCH

6.1 SUMMARY

A method has been developed to aid planners and designers of large energy facilities in the western U.S. to assess alternative strategies for acquiring and using water. The method has been tested on a case study and initial results suggest the approach proposed in this thesis offers a number of improvements over approaches found elsewhere in the literature. Improvements are realized because the method explicitly balances the costs of acquiring water (e.g. installing reservoirs, purchasing water rights) against the benefits attending its consumption at an energy facility (e.g. improved plant operating efficiencies). On the one hand water availability in the West tends to be stochastic and subject to institutional restrictions, factors that contribute to the cost of acquiring it. On the other hand various cooling system design options allow some degree of water conservation at an energy facility. For the most part earlier studies failed to explore this balance, as if the decision by the firm to consume water can be studied independently of the costs of acquiring a reliable supply.

In its current form the method examines the tradeoffs between the cooling system design, construction of a make-up water reservoir, and purchases of existing water rights for a single facility at a time. An important distinction is made between two possible substitutions: 1) for a fixed cooling system, the substitution of reservoir storage for purchases of existing water rights (Type I); and 2) the substitution of

the cooling system design for purchases of existing rights (Type II). This distinction is important for the reason that the response of the firm's demand schedule for existing water rights to changes in external economic and physical parameters is governed by the dominant substitution effect. For example, higher reservoir costs will shift the firm's demand schedule for existing rights up when Type I substitutions dominate, and will shift this schedule down when Type II substitutions dominate. The approach uses a small collection of models to quantify these tradeoffs. These models fall into five categories:

1. A water supply model to calculate the amount of water an energy facility will receive in any month as a function of the streamflow for that month and the number of water rights held by the firm.
2. Cooling system simulation models used to measure the monthly operating performance for the cooling system designs under consideration.
3. A reservoir simulation/water rights acquisition model to determine the tradeoff between installing make-up water capacity and purchasing water rights for any cooling system.
4. Operations models to minimize the operating costs for any dry-wet cooling systems under consideration.
5. A cost accounting model to keep track of the capital and operating costs associated with any particular strategy for acquiring and

using water at an energy facility.

6.2 CONCLUSIONS

The initial results from the case study suggest that an energy firm may turn to any one of a number of strategies for acquiring and using water. In this thesis these strategies have been defined in terms of the energy firm's options for conserving water consumption, building reservoirs, and purchasing water rights from existing users. By the same token, the results of this thesis also suggest that the tradeoffs between water for western energy and water for other purposes are more complex than earlier studies would have us suspect. Earlier studies, by and large, approached the question of water use from a regional perspective. In doing so these studies suffered from one of two drawbacks: they either failed to exploit the extreme seasonal variation in water availability in their analyses, or they failed to consider alternative cooling system designs for energy facilities. Under the former investigators will underestimate the costs involved in obtaining 'surplus' water. For this reason they will also underestimate the economic incentives confronting an energy firm to purchase existing water rights. In the latter case, on the other hand, investigators will overstate the firm's 'need' for water, even though they may properly account of the costs of acquiring it. An energy firm can respond to high water acquisition costs by designing the plant to consume less water. By ignoring this type of response investigators will tend to exaggerate the economic incentives to transfer water from existing uses

to energy.

The methodology proposed in this thesis eschews the 'elegant' regional approach for one which emphasizes the tradeoffs available to a single energy plant. This is clearly the preferred approach for designers of individual plants for whom the regional perspective is practically meaningless.

Nevertheless, this method may be used to examine water allocation tradeoffs at the regional scale; a level of aggregation that will continue to attract the interest of western water authorities and government agencies. The methodology can be used to decompose the regional water allocation problem by explicitly determining the demand for water (both gross consumption in general and consumption from particular sources in particular) at individual energy facilities. An improved regional model might begin by using the methodology as a 'screening' model to determine the tradeoffs between cooling system design, reservoir construction and water right purchases at individual energy facilities. The willingness to pay for water at the separate energy facilities can be compared with the willingness to pay for water in alternative uses in the region. Aggregation back to the regional level can be done by selecting different prices for water and observing how the energy facilities would be induced to select levels of water use that are comensurate with the available supply and with other uses in the region.

6.3 DIRECTIONS FOR FUTURE RESEARCH

The first area where future research appears most promising is to extend the methodology to synthetic fuel plants. The conditions for which synthetic plants need be cooled are considerably different than those for steam-electric power plants. Initial work by other investigators (Probststein and Gold; 1978) suggests dry-wet cooling can be economically competitive with cooling ponds and fully wet cooling towers at various locations in a synfuel facility. In all plants the cooling efficiency of dry towers is dependent on the temperature of the cooling fluid leaving the plant for the cooling system. In conventional steam-electric power plants this temperature cannot usually exceed 130 F. In synfuel plants, on the other hand, the feed streams from gas purifiers may enter the condenser at 240°F, while other process streams may enter the condenser at temperatures between 270 and 300°F. At these high temperatures it is often economic to initiate cooling with dry towers and follow this with some form of wet cooling. Probststein and Gold (1978) suggest that process streams at temperatures above 140°F can be economically cooled with dry cooling towers, and that streams at temperatures below 130°F should be cooled with fully wet towers (or, equivalently, cooling ponds). The implication here is that non-inferior strategies for acquiring and using water will favor Type II substitutions to a greater degree at a synfuels plant than at a steam electric power plant. As we have seen in the analysis of the case study Type II substitutions tend to both lower and flatten an energy firm's demand schedule for existing water rights. We can anticipate that a synfuels plant will have weaker incentives to purchase existing rights

than will comparably sized steam-electric plant.

Another area where future research would appear to substantially improve the methodology is within the water supply model. The current model has a number of improvements over other models proposed in the literature, particularly in terms of accounting for the stochasticity of surface water supplies and the water demands from existing right holders on a river. Nevertheless, the model currently operates under the assumption that the entire portion of a right that had historically been consumed can be transferred from one diversion point to the next without any reduction in the yield of the right. In actual practice, however, the transfer of a right may deprive junior right holders a portion of their water. In this case a party transferring a right will be legally bound to keep some fraction of the right at the prior point of diversion in order to meet non-injury provisions. Gerstle and Marks (1979) demonstrated that anywhere from 0-100% of the historically consumptive portion of a right might be legally transferred to a new point of diversion on the river. Their model explicitly accounts for both the seniority and the location of all rights along the level, neither of which are recognized in the current version of the water supply model.

A third area for future research should be to quantify the tradeoffs between the reliability with which the plant has water at its disposal and the options for acquiring and using it. Reliability in this case may represent both the frequency with which the plant is without water from its normal sources, and the duration of such periods when they occur.

Both design and operational issues come into play here. In terms of design the plant owners can obtain a desired level of reliability by installing larger or smaller reservoirs and by purchasing a larger or smaller number of existing rights. In terms of operation the energy firm might prepare for water shortages by scheduleing partial or complete plant shutdowns (for maintanance perhaps) for a few days at a time. It is concievable that the firm might ride out the drought by renting, for a temporary period of time, water rights from existing users. If dry-wet cooling is used the plant operators can select a revised operating schedule to promote greater water conservation. Operational measures are particularly attractive because snowpack measurements taken during the Winter and Spring can be used to estimate likely flow conditions in a river for the upcoming Summer. Thus, plant operators should be able to anticipate to some degree the possibility of being without water months in advance.

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APPENDIX 5-A   DERIVATION OF THE COEFFICIENTS USED
TO DETERMINE THE COST OF TRANSPORTING
MAKE-UP WATER TO AN OFF-STREAM SITE

Four items contribute to the cost of piping water to an off-stream plant site: the capital cost of the pipe, the pumps, and the pumping power capacity, and the lifetime cost of the energy required for the pumps. In the derivations to follow we will calculate the optimal pipe diameter as a function of the required flow through the pipe. We will assume the pumps operate year round (8760 hours) and deliver the average annual make-up water demand for each cooling system.

The head loss (in feet) through a pipe is the sum of the static head loss, which is independent of the flow through the pipe, and the dynamic head loss, which is a function of the flow rate. Dynamic head loss for steady, turbulent flow through pipes can be computed from the Darcy equation (Dailey and Harleman, 1973):

$$h_D = f \frac{L}{D} \frac{v^2}{2g} \quad (5.1 \text{ a})$$

where:

h_D = dynamic head loss (ft)

f = friction factor

L = the pipe length (ft)

V = the flow velocity (ft/sec)

D = the pipe diameter (ft)

g = the gravitational constant (32.2 ft/sec)

The pipe diameter may be replaced by the flow velocity and the flow rate, Q, in Equation (5.1 a):

$$h_D = f \frac{L \cdot V^2}{4 \sqrt{Q/V} \cdot \pi g} \quad (5.2 a)$$

The total pumping energy required is then:

$$PE = [h_S + h_D] \frac{.0843Q}{EF_p} \quad (5.3 a)$$

where:

PE = the pumping energy (KWe)

h_S = the static head loss (ft)

EF_p = the pump efficiency

The constant 0.0843 is the conversion factor from ft-lb/sec to KWe.

The present valued cost of the electric capacity needed to drive the pumps is:

$$POW = PE \cdot CAC \cdot PF \quad (5.4 \text{ a})$$

where:

POW = the present valued cost of the electric generating capacity (\$)

CAC = the unit capital cost of the electric generator (\$/KWe)

PF = the conversion factor from initial capital cost to present valued cost (includes discounted interest charges, insurance on equipment, etc.)

The data used to calculate the initial capital cost of the pump comes from Sebald (1976). This cost is a linear equation of the form:

$$PUMP = PF \cdot [P_1 + P_2 \cdot PE] \quad (5.5 \text{ a})$$

where PUMP is the present valued cost of the pump (\$), and the coefficients P_1 and P_2 are taken from Sebald, et al.

The data used to calculate the present valued cost of the pipe comes from Gold, et al., (1977), and is a linear function of the pipe length of the form:

$$PIPE = \sqrt{\frac{Q}{V\pi}} \cdot L \cdot PC \cdot PF \quad (5.6 \text{ a})$$

where:

PIPE = the present valued cost of the pipe (\$)

PC = the unit capital cost of the pipe (\$/ft dia/ft)

Finally, the present valued cost for pumping energy during the lifetime of the plant is:

$$EN = PE \cdot 8760 \cdot FC \cdot PV \quad (5.7 \text{ a})$$

where:

EN = the present valued cost of pumping energy (\$)

FC = the unit energy cost (\$/KWe)

PV = the conversion factor from annual cost to present valued cost

The total present valued cost of transporting water to an off-stream plant site becomes:

$$TOTAL = EN + PIPE + PUMP + POW \quad (5.8 \text{ a})$$

$$= \left[\frac{Q \cdot f \cdot L \cdot V^2 \cdot 0.00116}{\sqrt{Q/V} \cdot EF_p} + \frac{h_s \cdot Q \cdot 0.0843}{EF_p} \right] [8760 \cdot FC \cdot PV + PF \cdot P_2 + CAC \cdot PF] + P_1 \cdot PF + \sqrt{2Q/V\pi} L \cdot PC \cdot PF$$

The optimal flow velocity, V , may be determined by setting $\frac{d \text{ TOTAL}}{dV} =$ and solving for V :

$$V = \frac{0.5642 \cdot PC \cdot PF \cdot EF}{0.0029 \cdot f [8760 \cdot FC \cdot PV + PF \cdot P_2 + CAC \cdot PF]} \quad (5.9 \text{ a})$$

For this thesis the following parameters and cost coefficients are used in equations (5.1 a)-(5.9 a):

P_1	= \$1.644 million	[Sebald, 1976]
P_2	= \$452/ft	[Sebald, 1976]
PC	= \$75/ft/ft	[Gold, et al., 1977]
f	= 0.016	
h_s	= 800 ft	
EF_p	= 85%	
PV	= 19.79	[discount rate = 4%; lifetime = 40 years]
PF	= 2.28	
CAC	= \$600/KW _e	[baseload capacity]
FC	= \$0.008/KWH _e	[baseload plant energy]

Using Equation (5.9 a) we find the optimal flow velocity is 7.8 ft/sec. Substituting this value into Equation (5.8 a), we can express the total present valued cost for each cooling system as a function of its average make-up water flow rate and the transport distance:

$$TOTAL = 3.75 + .3 \cdot Q + .44 \cdot Q^5 \cdot L \quad (5.10 \text{ a})$$

where the transport distance, L, is now measured in miles, and the total cost, TOTAL, is measured in millions.

For the six cooling systems examined in this thesis the costs of transporting water become:

475 acre cooling pond:	7.5	+	1.53 L	Q = 12.1 cfs
800 acre cooling pond:	8.1	+	1.65 L	Q = 14.0 cfs
500 foot wet cooling tower:	7.2	+	1.47 L	Q = 11.1 cfs
40% dry-60% wet cooling tower:	5.0	+	.90 L	Q = 4.2 cfs
30% dry-70% wet cooling tower				
one unit:	5.3	+	1.00 L	Q = 5.1 cfs
two units:	5.2	+	.96 L	Q = 4.8 cfs
50% dry-50% cooling pond				
one unit:				
two units:				

As noted earlier in Chapter 5, the transport costs for the dry-wet cooling systems are calculated using the average annual make-up water rates found with the optimal operating policies.

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