CHAPTER 7

EVALUATING PUMPED-STORAGE HYDROPOWER

7-1. Introduction.

a. Purpose and Scope.

(1) Pumped-storage is a special type of hydropower development, in which pumped water rather than natural streamflow provides the source of energy. This chapter describes the general concepts of pumped-storage operation and outlines the planning studies required to evaluate a pumped-storage project.

(2) There are two basic types of pumped-storage projects:

- pure (or off-stream) pumped-storage projects, which rely entirely on water that has been pumped into an upper reservoir as their source of energy.

- combined pumped-storage projects, which use a combination of pumped water and natural streamflow to produce energy. These projects are also called pump-back projects, and the latter term will be used in this manual.

Both types of projects can be designed to operate on either a daily/weekly cycle (like a conventional hydro peaking plant with pondage) or on a seasonal cycle.

(3) This chapter deals primarily with surface type pumped-storage projects. However, it should be recognized that underground pumped-storage projects, where the powerhouse and lower reservoir are located below the surface, are sometimes viable alternatives for meeting peaking demands (see Section 7-7d). Evaluation procedures for underground projects are generally similar to those which would be followed in examining surface type projects.

(4) Pumped-storage operation can be best understood by examining an off-stream pumped-storage project which operates on a daily/weekly cycle (the most common type of pumped-storage development in the United States). The early sections of this chapter discuss the analysis of this type of project. Later sections are devoted to pump-back, seasonal pumped-storage, and other aspects of pumped-storage development.

(5) Following is an outline of the major topics covered in each of the sections in this chapter.

- 7-2: characteristics of daily/weekly cycle pumped-storage projects

- 7-3: overall procedure for evaluating daily/weekly cycle pumped-storage projects

- 7-4: routing studies required for daily/weekly cycle pumped-storage projects

- 7-5: economic analysis of daily/weekly cycle pumped-storage projects

- 7-6: analysis of pump-back projects

- 7-7: screening studies, seasonal pumped-storage, multiple-purpose pumped-storage, and special problems associated with pumped-storage development.

b. Basic Concept of Pumped-Storage.

(1) The basic idea behind pumped-storage is to convert relatively low-cost off-peak thermal generation from nuclear or coal-fired plants into high-value on-peak power. This is accomplished at a pumped-storage hydro plant by using the off-peak thermal energy to

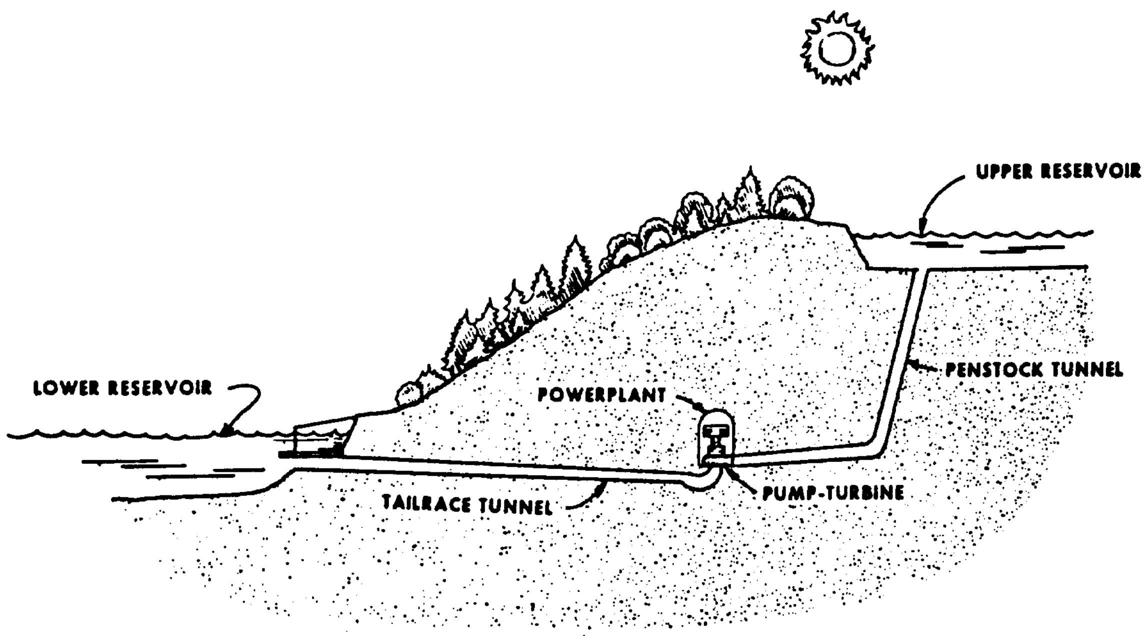

Figure 7-1. Diagram of an off-stream pumped-storage project

pump water from a lower reservoir to an upper reservoir (see Figure 7-1). The water is then released to generate power during peak demand periods.

(2) Most pumped-storage projects operate on either a daily or weekly cycle. At daily-cycle plants, the storage required to support each day's generation must be replenished by pumping the following night (Figure 7-2). In the case of weekly cycle plants, sufficient storage capacity is provided to permit a portion of the pumping to be accomplished on weekends (Figure 7-3). Pumped storage can also be

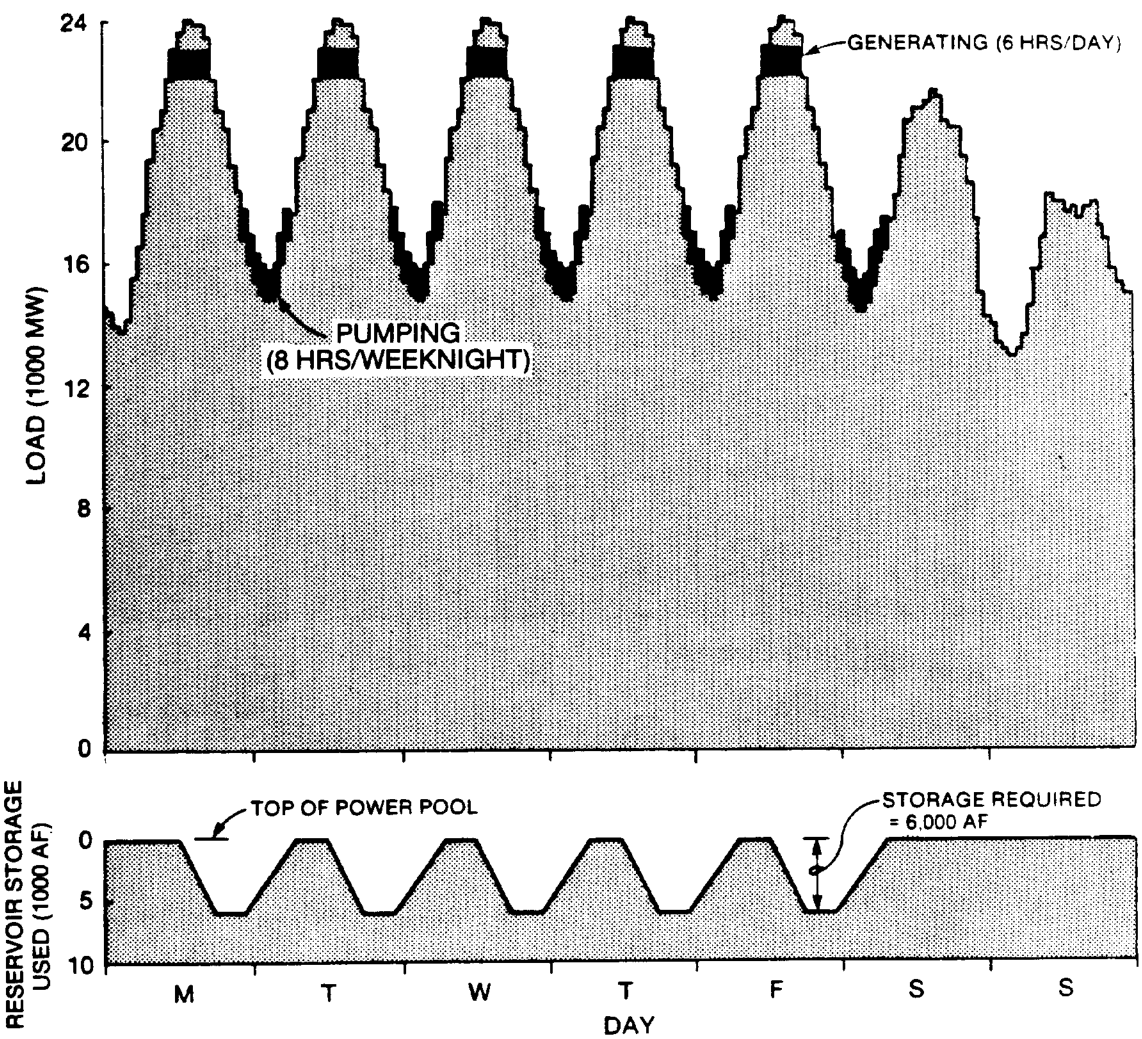

Figure 7-2. Operation of daily cycle pumped-storage project

used to store energy on a seasonal basis, but projects of this type usually store water for other purposes in addition to hydropower.

(3) Pump-back capability might be added at conventional hydro projects for two reasons: (a) to firm up peaking capacity during periods of low streamflow, or (b) to permit large peaking installations to be constructed at sites with relatively low natural flows. A pump-back project is basically a conventional hydro project

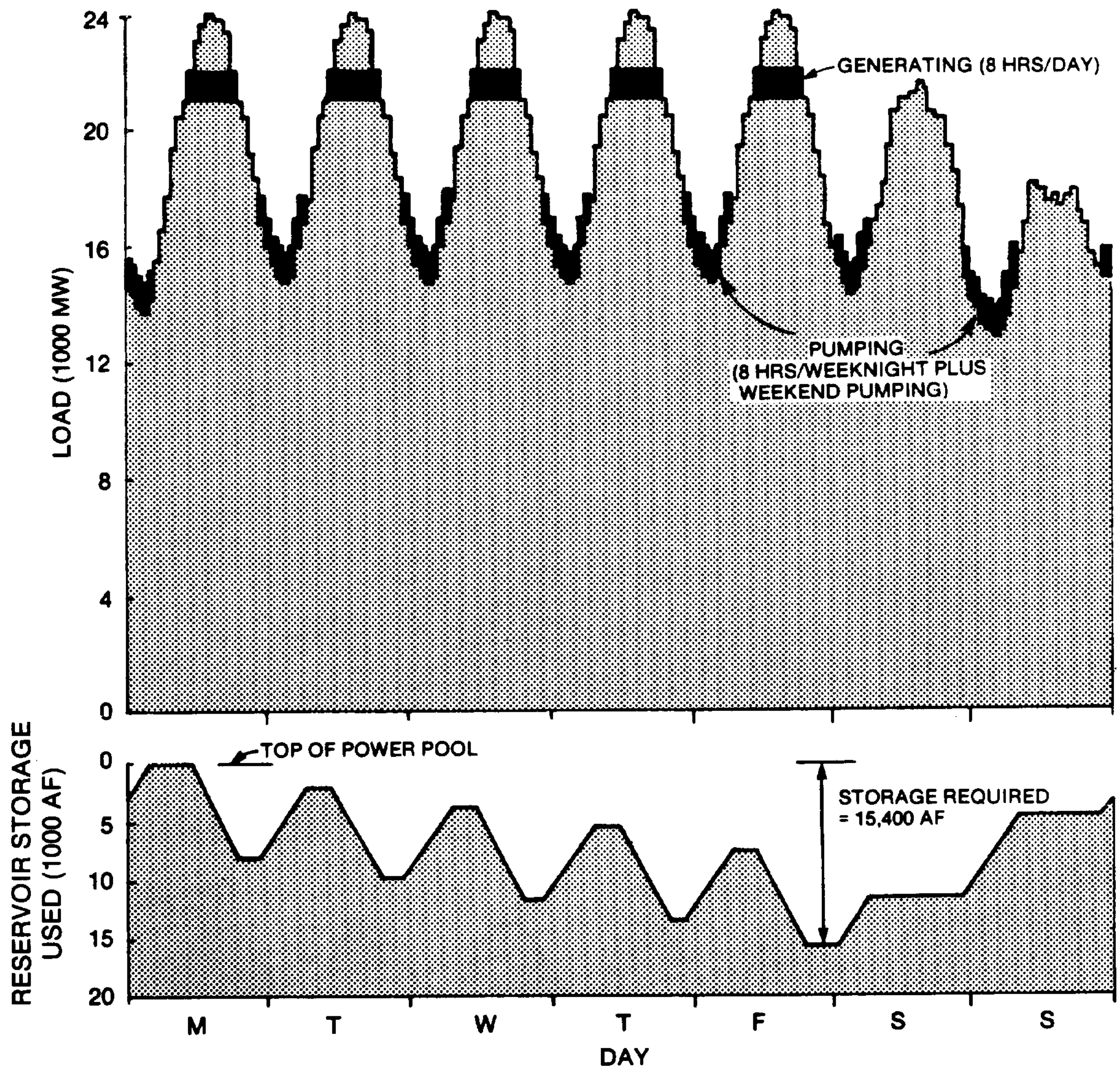

Figure 7-3. Operation of weekly cycle pumped-storage project

at which some or all of the generating units can also operate as pumps. Much of the time, natural flows (in combination with available pondage) may be sufficient to support the plant's peaking capacity. During low flow periods, however, a portion of the peaking discharge would be pumped back at night (or on weekends), to insure that sufficient water is available to meet peaking requirements on subsequent days. A reservoir must exist immediately downstream to capture these releases, and store them until pump-back can be accomplished.

(4) The concept of pumped-storage hydro has existed for many years, and pumped-storage projects were constructed in Europe as early as 1908. However, it was not until after reversible pump-turbines were perfected in the 1950's that pumped storage became an important source of peaking capacity in the United States.

c. Types of Pumped-Storage Projects.

(1) Introduction. Within the two broad categories of pumped-storage hydro, a number of different types of developments have evolved. Following are descriptions and examples of each of these different types. For details on the locations and characteristics of the example projects, refer to the tables in Section 7-1d.

(2) Off-Stream: Daily-Weekly Cycle (General). This type of development typically involves the use of a lower reservoir on a stream or other water body, which provides the source of water, and an upper reservoir located adjacent to the lower reservoir. The upper reservoir may also be located on a stream, but usually it is not. This type of development relies entirely on pumped water as a source of energy. At some projects, the upper reservoir is constructed on a mountain top, where there is little or no local inflow (Taum Sauk and Northfield Mountain are examples). Projects of this type have sufficient reservoir storage to permit operation on a daily or weekly cycle, which is typically sufficient to generate 6 to 20 hours continuously at full output.

(3) Offstream: Daily-Weekly Cycle (Types of Lower Reservoirs). Different types of water bodies have been used as lower reservoirs for off-stream projects. Ludington uses Lake Michigan, while the now-cancelled Cornwall project would have pumped from an open reach of the lower Hudson River. Salina and Seneca use existing multiple-purpose storage projects as lower reservoirs. Seneca (Figure 2-17) is of special interest because it uses a Corps of Engineers reservoir (Kinzua), and the powerhouse is designed to discharge to either the reservoir, or the river below Kinzua Dam, or both. In this way the head at Kinzua Dam, which has no powerhouse of its own, can be utilized also. TVA's Raccoon Mountain project pumps from the pool

behind Nickajack Dam, a navigation and run-of-river power project. Helms uses existing hydro projects as both upper and lower reservoirs. Most of the other off-stream pumped-storage projects use existing pondage projects or specially constructed lower reservoirs. The Corps of Engineers has investigated off-stream projects which would use the Fort Randall Reservoir on the Missouri River (Gregory County) and run-of-river navigation projects on the Arkansas River (Petit Jean-White Oak).

(4) Offstream: Seasonal. Rocky River was the first pumped-storage project to be constructed in the United States (1929). It was designed to pump water into a man-made lake during the high flow season, with releases being made during low flow periods to produce power at-site and firm up generation of a series of run-of-river projects located downstream on the Housatonic River. A number of other seasonal off-stream pumped-storage projects have been studied, but in most cases the primary objective has been to store water for purposes other than power. San Luis is the only large project of this type to have been constructed in this country. At San Luis, irrigation water is pumped into the reservoir during the winter months, when irrigation demands are low. During the winter, water is available in the lower Sacramento River, and the cost of pumping energy is relatively low. During the peak irrigation season, when energy has a higher value, water is released into the Delta-Mendota Canal and the California Aqueduct, producing power at both the San Luis and O'Neill powerplants (see Section M-3). The Corps of Engineers and other agencies have studied large off-stream reservoirs in the Columbia River basin, which is used to to supplement the power storage of the existing reservoir system. However, the relatively small gain in storage benefits that can be realized from additional storage, combined with the high cost of constructing large off-stream reservoirs, has thus far discouraged this type of development.

(5) Pump-Back: Single-Purpose Power Projects. Reversible units may be installed at on-stream hydro projects for one of two reasons: (a) to firm up peaking capacity during occasional periods of low flow, or (b) to permit large peaking installations at sites which are favorable for construction of hydro projects but where natural flows are too low to support such installations. Most single-purpose pump-back projects fall into the second category. At Jocassee and Smith Mountain, nearly 75% of the generation results from pumped-storage. At Horse Mesa and Mormon Flat, small conventional powerplants have been supplemented by large pump-turbine units, to increase the plant's peaking capabilities.

(6) Pump-Back: Multiple-Purpose Projects. Pump-turbines have also been installed at a number of multiple-purpose projects. One reason for this is that the seasonal discharge requirements of other

functions sometimes limit conventional power operation, and pump-back is required to firm up the peaking capacity. Oroville is a large seasonal reservoir which serves as the primary storage facility for the California Water Project. Most of the time, releases for water supply are sufficient to support the plant's installed capacity, but during low discharge periods, pump-back must be utilized to insure that peaking power committments are met. Truman, DeGray, and Cannon are Corps of Engineers projects having large flood control storage requirements. Power storage is limited, so pump-back capability was provided in order to firm up the peaking capacity during occasional low flow periods. In the system where DeGray is operated, there is at present no low-cost, off-peak energy available for pumping, so the plant has thus far been used only for conventional generation and spinning reserve. At Truman, unanticipated fish problems have precluded pumping to date. Carters (Figure 2-18) is another Corps of Engineers multiple-purpose storage project where pump-back has been used to support a large peaking installation, with half of the project's generation being supported by pumping. Richard B. Russell is a pondage project which develops the reach between two large storage projects on the Savannah River. The original power installation consisted of conventional peaking units, but the addition of reversible units made it possible to double the peaking capacity.

(7) Diversion Type: Single-Purpose Power. A diversion type project is one where water is diverted from one river basin to another. In such cases the pumping plant and generating plant would be separate installations. An example of a single-purpose hydropower diversion project would be where water is pumped into a storage reservoir located in an adjacent basin where the topography and other characteristics are more suitable for hydropower development. At some developments, the water thus diverted passes through a series of downstream generating plants, thereby realizing a large gain in generation in comparison with the pumping energy expended. No projects of this type are located in the United States, although some have been developed in Europe and South America.

(8) Diversion Type: Multiple-Purpose. Pumped-storage can also be incorporated in inter-basin diversion projects constructed to transport water for irrigation or municipal water supply. Frequently the power installations at projects of this type are designed only to recover as much of the pumping energy as possible, but in at least two cases reversible units have been installed to provide peaking power. Castaic is located at the terminus of West branch of the California Aqueduct, and it is designed primarily to recover energy from water conveyed over a mountainous segment of the Aqueduct. However, at times it operates as an off-stream pumped-storage peaking project.

Similarly, reversible units have been installed in the pumping plant constructed to pump water from Grand Coulee reservoir to Banks Lake, the equalizing reservoir for the Columbia Basin irrigation project. Normally these units function as pumps, but they can operate as generating units during the winter months, when pumping loads are minimal and power demand is high.

(9) Other Types of Projects. There are also several examples of pumped storage being used to provide pondage for conventional hydro plants. The most notable examples are the U.S. and Canadian power developments at Niagara Falls. Substantial flows must be maintained over the falls during the daylight hours, thus limiting the amount of water that can be diverted for power production during the hours when power demands are greatest. Tunnels have been constructed to divert water around the falls at night, and on the U.S. side this water is pumped into the Lewiston Reservoir. During the daylight hours, this water is released to produce power at both Lewiston and at the Robert Moses conventional generating plant, which discharges into the Niagara River below the falls. A similar development exists on the Canadian side of the river.

d. Existing Pumped-Storage Projects. Table 7-1 lists the major off-stream pumped-storage projects in the U.S. and their characteristics. Table 7-2 lists the major pump-back projects. Figure 7-4 shows the locations of these projects. The numbers on the map correspond to the project numbers on Tables 7-1 and 7-2. For further details on specific projects, Part 3 of reference (12) and Sections 2-2, 2-3, and Appendix B of reference (48j) should be consulted. Reference (22) contains an extensive bibliography of pumped-storage articles.

7-2. General Characteristics of Off-Stream Pumped-Storage Projects.

a. Introduction. This section describes the general characteristics of off-stream pumped-storage projects: desirable site characteristics, the operating cycle, storage requirements, plant size, head range, pump-turbine characteristics, rated capacity, plant operating characteristics, cycle efficiency, charge/discharge ratios, reliability and availability, plant factor, size and number of units, and other factors. Much of the material presented in this section has been drawn from Volume 3 of EPRI's Assessment of Energy Storage Systems Suitable for Use by Electric Utilities (12). References (22) and (48j) are also useful sources of information. For information on the characteristics of pump-back projects, see Section 7-6.

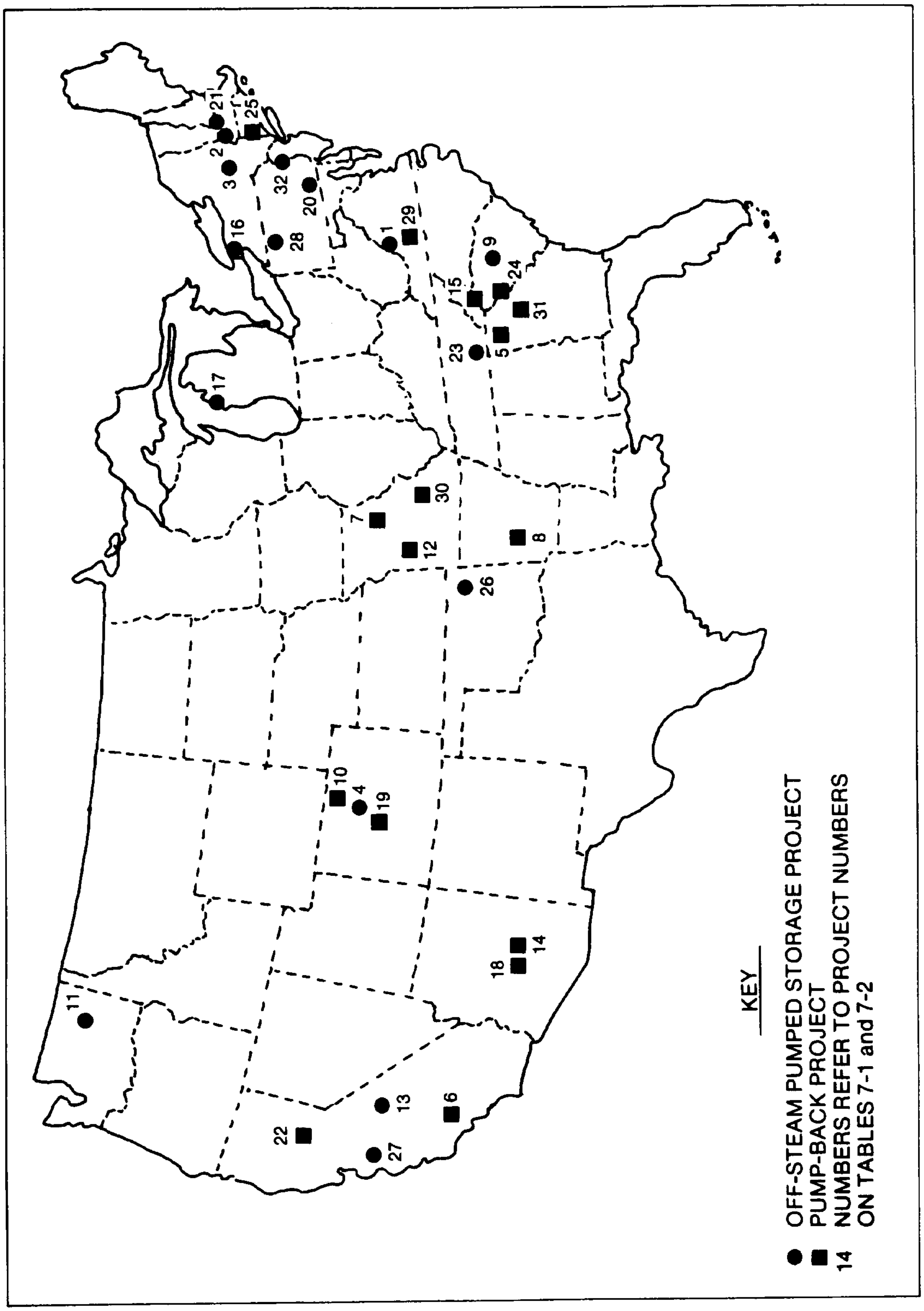

Figure 7-4. Major pumped-storage projects in the United States

TABLE 7-1. Major Off-Stream Pumped-Storage

Map No. 12/	Name of Project	State	Owner
1.	Bath County	VA	Virginia Power Company
2.	Bear Swamp	MA	New England Power Company
3.	Blenheim-Gilboa	NY	Power Authority, State of New York
4.	Cabin Creek	CO	Public Service Company of Colorado
9.	Fairfield	SC	South Carolina Electric and Gas Co.
11.	Grand Coulee 13/	WA	U.S. Bureau of Reclamation
13.	Helms	CA	Pacific Gas and Electric
16.	Lewiston-Niagara	NY	Power Authority, State of New York
17.	Ludington	MI	Consumers Power/Detroit Edison
20.	Muddy Run	PA	Philadelphia Electric Company
21.	Northfield Mountain	MA	CP&LCo./HE&LCo./WMECo. 4/
23.	Raccoon Mountain	TN	Tennessee Valley Authority
26.	Salina	OK	Grand River Dam Authority
27.	San Luis	CA	U.S. Bureau of Reclamation
28.	Seneca (Kinzua)	PA	CEICo./PECo. 6/
30.	Taum Sauk	MO	Union Electric Company
32.	Yards Creek	NJ	PSG&ECo./JCP&LCo. 8/

1/ rated generating capacity
2/ utilizes seasonal irrigation storage
3/ utilizes seasonal power storage
4/ Connecticut Power and Light Company/Hartford Electric and Light Company/Western Massachusetts Electric Company
5/ different units operate in different head ranges
6/ Cleveland Electric Illuminating Co./Pennsylvania Electric Co. (GPU)
7/ two 198 MW reversible units and one 26 MW conventional unit

Projects in the United States, 1 January 1985

On-Line Date	Units	Total Capacity (MW) 1/	Head Range (Feet)	Storage (Hours)	Map No. 12/
1985 11/	6	2100	1080 10/	11.3	1.
1974	2	600	660-750	5.6	2.
1973	4	1000	1001-1088	11.6	3.
1966	2	300	975-1190	5.8	4.
1979	8	511	155-169	8.0	9.
1973	6	314	262-358	2/	11.
1984	3	1050	1560 10/	3/	13.
1962	12	240	65-100	9/	16.
1973	6	1979	296-362	8.7	17.
1967	8	800	346-401	14.2	20.
1972	4	1000	700-815	8.5	21.
1979	4	1530	870-1017	24.0	23.
1968	6	260	223-243	19.0	26.
1968	8	424	114-316 5/	2/	27.
1970	3 7/	422	642-791	11.2	28.
1963	2	408	714-879	7.7	30.
1965	3	387	651-735	8.8	32.

8/ Public Service Gas & Electric Co./Jersey Central Power & Light Co.
9/ primary function of pumped-storage is to support large conventional hydro plants
10/ rated head (generating) of pumped-storage
11/ scheduled on-line date
12/ refers to location number on Figure 7-4; missing numbers are on Table 7-2
13/ Grand Coulee Pumping Plant

TABLE 7-2. Major Pump-Back

Map No. 1/	Name of Project	State	Owner
5.	Carters	GA	Corps of Engineers
6.	Castaic	CA	LADWP/CDWR 4/
7.	Clarence Cannon	MO	Corps of Engineers
8.	DeGray	AR	Corps of Engineers
10.	Flatiron	CO	Bureau of Reclamation
12.	Harry S. Truman 6/	MO	Corps of Engineers
14.	Horse Mesa	AZ	Salt River Project Authority
15.	Jocassee	NC/SC	Duke Power Co.
18.	Mormon Flat	AZ	Salt River Project Authority
19.	Mt. Elbert	CO	U.S. Bureau of Reclamation
22.	Oroville (Hyatt)	CA	California Dept. of Water Res.
24	Richard B. Russell	GA/SC	Corps of Engineers
25.	Rocky River	CT	Connecticut Power & Light Company
29.	Smith Mountain	VA	Appalachian Power Company
31.	Wallace	GA	Georgia Power Company

1/ number of reversible units/number of conventional units
2/ total reversible generating capacity/total conventional generating capacity
3/ at some plants, different units operate in different head ranges
4/ Los Angeles Department of Water & Power/California Department of Water Resources

Projects in the United States, 1 January 1985

On-Line Date	Units 1/	Total Capacity (MW) 2/	Head Range (Feet) 3/	Storage (Hours)	Map No. 7/
1975	2R/2C	250/250	320-427	44	5.
1973	6R/1C	1275/56	891-957	14.6	6.
1984	1R/1C	31/27	59-107	8	7.
1971	1R/1C	28/40	144-188	5/	8.
1954	8R/2C	480/63	140-290	4000 5/	10.
1981	6R/0C	160/0	41-79	19	12.
1972	1R/3C	100/30	151-259	8	14.
1974	4R/0C	610/0	276-331	192	15.
1971	1R/1C	49/9	100-138	11	18.
1981	2	200	400-475	13	19.
1968	3R/3C	293/351	500-675	5/	22.
1987 8/	4R/4C	475/346	135-163	26	24.
1929	2R/2C	7/24	190-219	830	25.
1965	3R/2C	236/300	174-195	5	29.
1980	4R/2C	216/108	94-97	42.9	31.

5/ utilizes multiple-purpose seasonal storage
6/ not currently operating in pumping mode due to fishery problems
7/ refers to location number on Figure 7-4; missing numbers are on Table 7-1
8/ scheduled on-line date for pump-back units, first conventional unit was placed in service in 1985.

b. Desirable Site Characteristics.

(1) General. In order to be cost-effective, an off-stream pumped storage site should have most or all of the following characteristics:

- geologic conditions should be suitable for water-tight reservoirs
- head should be as high as possible
- length of water conduit (intake tunnel, penstock, and discharge tunnel) should be as short as possible
- reservoir sites should require minimum excavation and embankment
- use existing reservoir for lower reservoir, if possible
- both reservoirs should have suitable drawdown characteristics
- site should be suitable for a large power installation
- site should be located reasonably close to load centers or transmission corridors
- source(s) of relatively low cost pumping energy should be available.

Note that these are all primarily engineering and economic characteristics. Environmental and socio-economic criteria are also important, and in many cases they may dominate the site selection process. However, this manual is limited to discussing engineering aspects of hydropower planning. References (12) and (22) and standard references on environmental impact evaluation give further information on the environmental aspects of pumped-storage development. The availability of relatively low-cost pumping energy is also a prerequisite to consideration of pumped-storage development, but this is addressed under the operational and economic studies, rather than under site evaluation.

(2) Head. Reservoir storage requirements are inversely proportional to head (Figure 7-5), so reservoir costs can be minimized by selecting a site with a high head. Hydraulic capacity is also inversely proportional to head, so penstock diameter, and hence penstock costs, can also be minimized by maximizing head. For a given plant capacity, powerhouse costs are lower for high head plants. This is because the units run at higher speeds and high-speed machines are

smaller than low-speed machines. Because smaller water volumes are required at high head plants, reservoir drawdowns are usually smaller at both reservoirs.

(3) Length of Water Conduits. Costs of water conduits (intake tunnels, penstocks, and discharge tunnels) can represent one-quarter or more of a pumped-storage project's costs, so sites should be sought which will require minimum penstock and discharge tunnel lengths.

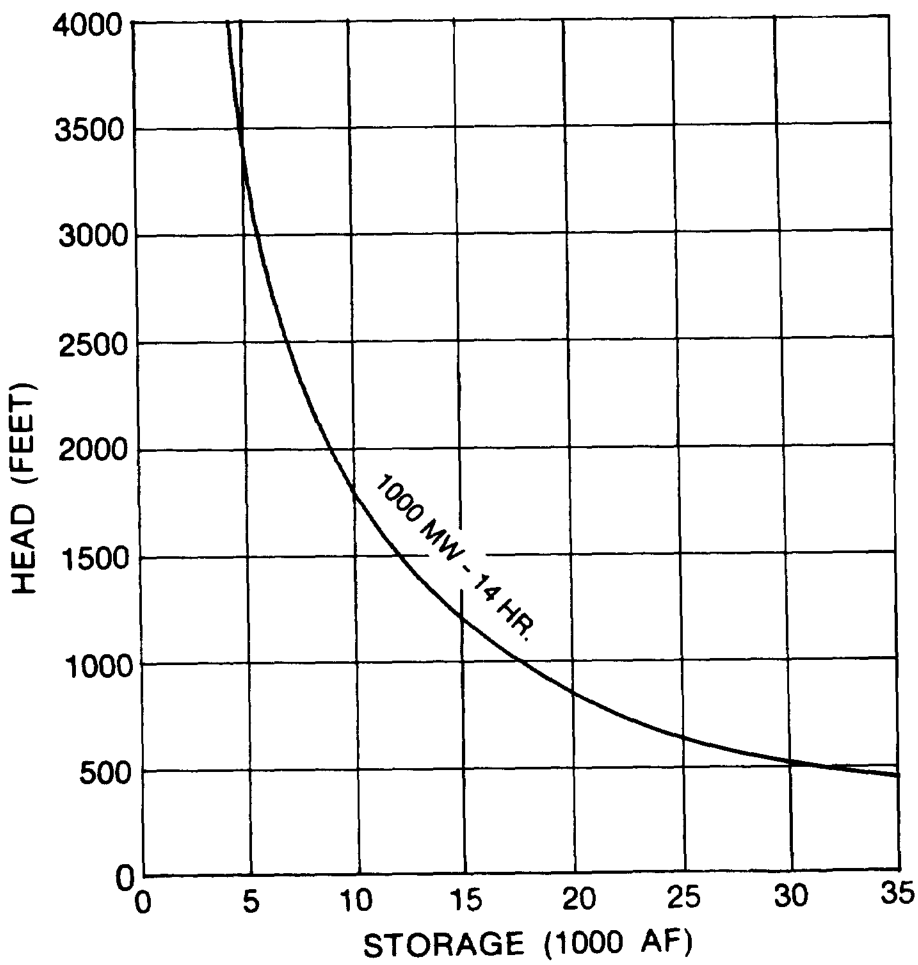

Figure 7-5. Reservoir storage required vs. head for 1000 MW plant with 14 hours of storage

This is particularly important at the lower head sites, because of the larger penstock and tunnel diameters involved. The economic limits to length of water conduits is a function of head and can be expressed in terms of horizontal length to head (L/H) ratios. Recent experience suggests that maximum acceptable L/H ratios range from 10 to 12 for high-head (1200-1500 ft.) projects down to 4 to 5 for low-head (500-600 ft.) sites.

(4) Upper Reservoirs. Upper reservoirs are usually constructed either with a dam across a natural valley or with an enclosure dike around a flat area, often on a hilltop. To minimize costs, sites should be sought where minimum excavation and embankment volumes are required, and sites having natural depressions are particularly desirable in this regard. Large drawdowns may cause slope instability, so sites with large, relatively shallow reservoirs are usually preferred to narrow, steep reservoirs. Slope treatment can sometimes alleviate this problem, but it can be expensive. Water-tight reservoirs are also essential, to minimize leakage losses (which in the case of the upper reservoir results in energy loss).

(5) Lower Reservoirs. Project costs can often be reduced by using existing reservoirs as lower reservoirs. However, care should be taken to insure that sufficient storage is available to handle fluctuations due to pumped-storage operation in addition to fluctuations resulting from existing reservoir operations. Because of the limited head range for efficient pump-turbine operation (Section 7-2f) and submergence requirements (Section 7-2q), caution should be exercised when considering the use of existing multiple-purpose reservoirs with large fluctuation ranges. When new lower reservoirs are required, sites with minimum embankments and relocation costs should be sought. Since new lower reservoirs are usually located on existing streams and are more generally accessible to the public, they should be designed to minimize daily and hourly fluctuations in order to insure public safety and to minimize environmental impact. Minimizing leakage losses is important here also, unless there is an abundant water supply.

(6) Plant Size. To minimize unit costs, most single-purpose off-stream pumped-storage plants are planned for relatively large capacities, with existing U.S. plants ranging in size from 300 MW to 2000 MW. Most recent plants have been in the 1000 MW or greater range. An additional factor encouraging large developments is the difficulty of obtaining site approval because of environmental and other factors. Total environmental impact (as well as study costs) can often be minimized by concentrating developments at one or two larger sites rather than many smaller sites.

(7) Geologic Conditions. It is beyond the scope of this manual to discuss geologic criteria for pumped-storage development, but it should be noted that geologic conditions are a key factor in evaluating the suitability of a site.

(8) Site Selection. It is seldom possible to locate sites which meet all of these criteria, in part because of the wide variations in topographic and geologic conditions around the country. As a result, trade-offs are usually required in the site selection process. It is because of these variations in conditions that specific ranges have not been recommended for head, length of water conduit, and plant size. For example, in some parts of the country, the topography is such that numerous sites are available with heads of 1000 feet or more. In such areas, plants of 1000 MW and larger can usually be constructed quite economically, and penstock/tunnel lengths of up to about two miles may be acceptable. In other areas, heads of 300-400 feet may be the highest obtainable. In such situations, short penstock lengths and reservoirs with minimum embankment and excavation requirements are much more important. The L/H ratios mentioned in paragraph (3) are helpful guidelines in estimating the maximum economical penstock and tunnel length for a given head. When heads are low, smaller plant sizes may also be necessary. At sites with low heads, the larger plant discharge and reservoir storage requirements per kilowatt of installed capacity will often dictate smaller installations than at high-head sites.

c. Operating Cycle.

(1) Paragraph 7-1b(2) and Figures 7-2 and 7-3 describe the two basic operating modes for off-stream pumped-storage projects, the daily and weekly cycles. The type of cycle utilized for a given project and the characteristics of that cycle are usually defined by the characteristics of the power system in which the plant will be operating: specifically, the number of off-peak pumping hours available each week-night and the number of on-peak generating hours required each weekday. In the following discussion, pumping and generating times are expressed in equivalent hours of full-load operation each day (at rated capacity in the generating mode). In actual operation, plants often operate at partial loadings part of the time, but equivalent hours of full-load pumping and generation are often used to simplify the analysis.

(2) Two different criteria may govern the operation of an off-stream pumped-storage project: economic dispatch and must-run operation. Normally, project operation is based on economic dispatch: i.e., the project is operated only if the value of the on-peak thermal energy that would be displaced by pumped-storage project generation exceeds the cost of the pumping energy. However, during periods of

high power demand and/or numerous plant outages, the project's capacity may be required so that the power system can meet its peak load requirements. In such cases, the project may be operated even though relatively high cost energy may be required to refill the reservoir during off-peak hours. This is sometimes called a "must-run" operation, as opposed to economic dispatch.

(3) The operating cycle required to perform the must-run operation helps to define a project's reservoir storage requirements and may serve as the basis for establishing its dependable capacity. The operating cycle, storage requirements, installed capacity, and project economics are all interrelated, and an iterative process is required to select the best plant size (see Section 7-3). However, one of the first steps in the analysis is to define a preliminary operating cycle. This is done through examination of the load shape and consultation with one or more of the entities familiar with the operation of the area power system: the regional Power Marketing Administration, FERC, and local utilities.

(4) Load shapes must be developed for typical peak demand weeks. Normally these shapes would be based on historical data, but they should be adjusted if necessary to meet expected changes in load shape. These changes could be caused by changes in the use pattern, changes in the customer mix, and the effects of load management. The analysis of the operating cycle should not be limited to the annual peak demand period. In some systems, the load shape is broader in off-peak periods, requiring more carry-over storage to support the capacity in the peak-demand weeks.

(5) Through examination of these load shapes, it should be possible to determine the maximum number of off-peak pumping hours available, which is normally in the 6 to 8 hour range on week-nights. In making this analysis, it should be kept in mind that pumping can be done in single-unit increments. In some off-peak hours, there may not be sufficient pumping energy to support the entire plant, but pumping could be accomplished with one or two units. This should be accounted for in estimating the equivalent number of full-load pumping hours available. Generally, the number of hours of available off-peak pumping energy is inversely related to the size of the pumped-storage plant in relation to the system load.

(6) The number of on-peak generating hours required is more difficult to define, because it is a function of the system generation mix and economics as well as load shape. Preliminary studies should consider a range of hourly generation requirements. If peaking capacity is required for an equivalent of only 4 to 6 hours at full capacity, the project can usually operate on a daily cycle (Figure 7-2). A daily cycle operation requires the minimum amount of

reservoir storage per kilowatt of installed capacity. However, a system often requires that peak output be maintained for more than 4 to 6 hours per day. To support this type of operation, a plant must be operated on a weekly cycle, with some of the pumping being accomplished on weekends (Figure 7-3). A reasonable range of alternatives for initial study might include a daily cycle and two or more weekly cycles, covering a range of equivalent full-load generation from 5 to 9 hours per weekday.

(7) It should also be mentioned that in most power systems, there are periods when system energy costs preclude the operation of pumped-storage: either the available off-peak energy is too costly, or the on-peak loads are already being carried with lower-cost generation. During these periods, the pumped-storage capacity is usually assigned to operating reserve, where its quick-start capability permits it to serve quite effectively.

d. Storage Requirements.

(1) For planning purposes, reservoir storage requirements are defined initially in terms of equivalent hours of full-load generation. This parameter is primarily a function of power system operation. Once this parameter has been defined, the volume storage requirements of specific sites can be determined by taking into consideration the site's head characteristics and the desired plant size.

(2) For a daily cycle plant, the number of hours of full-load generation that can be achieved each day (and hence the minimum reservoir storage requirements) is a function of the number of hours of off-peak pumping energy that are available each night, the overall cycle efficiency, and the charge/discharge ratio. The cycle efficiency, which is discussed in detail in Section 5-2j, accounts for machine efficiency and penstock losses in both the pumping and generating portions of the operating cycle. The charge/discharge ratio is the ratio of the unit's average pumping load to its rated generating capacity. This parameter is a characteristic of the pump-turbine runner design and how the unit is rated (see Section 5-2k).

(3) An example will illustrate how these parameters are related. Take for example a daily cycle plant with a cycle efficiency of 70 percent and a charge/discharge ratio of 1.1, operating in a system where seven hours of off-peak pumping energy is available each weeknight. Such a plant would require a reservoir with a minimum of (7.0 hours) x (0.70) x (1.1) = 5.4 hours of usable storage capacity.

(4) Similarly, the minimum storage requirements for a weekly cycle plant could be estimated using the following equation:

$$\text{Hours of Storage } (t_s) = 5(t_g) - 4(t_p)(E_c)(C_r) \qquad \text{(Eq. 7-1)}$$

where: t_g = equivalent hours of full-load generation per weekday
t_p = equivalent hours of pumping at full capacity per weeknight
E_c = overall cycle efficiency
C_r = charge/discharge ratio

(5) Figure 7-6 shows how storage requirements vary with number of hours of equivalent full-load generation per weekday for a project with the characteristics described in paragraph (2). It can be seen from both Equation 7-1 and Figure 7-6 that storage requirements increase by five hours for each additional hour of full-load generation. Note that the storage requirement values in Figure 7-6 are based on specific assumptions regarding pumping time, cycle efficiency, and charge/discharge ratio. Storage requirements can be reduced if (a) more night-time pumping is available, (b) a higher cycle efficiency can be obtained, (c) units with a higher charge/

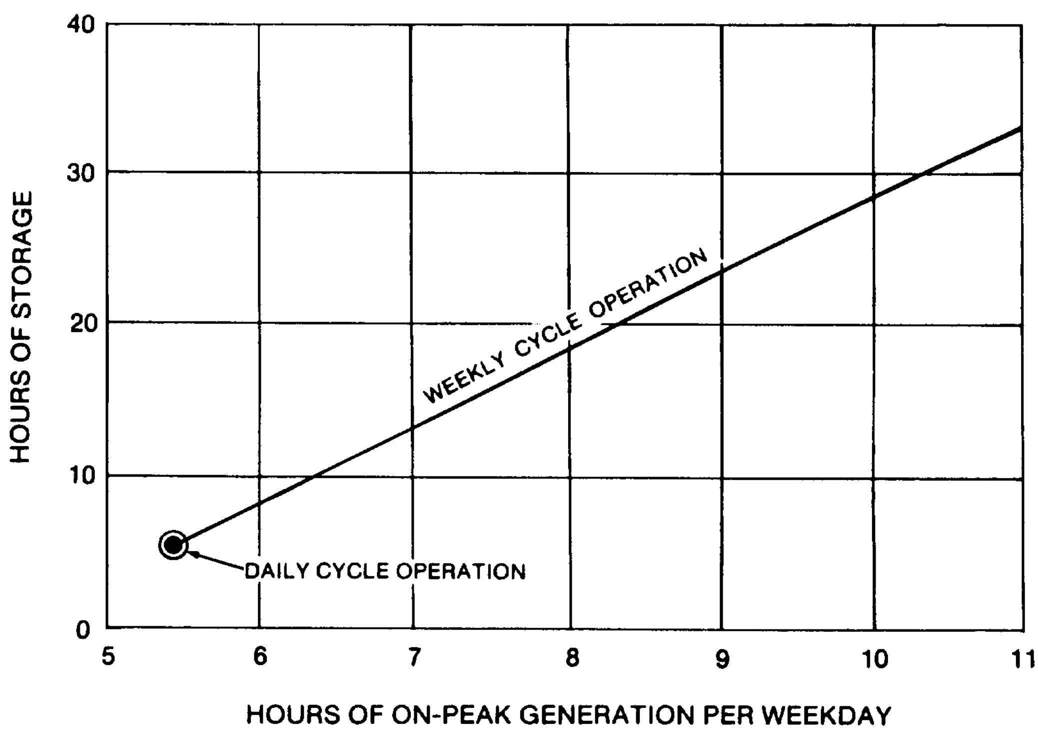

Figure 7-6. Reservoir storage requirements (in hours) versus hours of on-peak generation for plants operating in a system where seven hours of pumping can be done each week-night

discharge ratio are selected, or (d) the units are derated in the generating mode.

(6) Another key point is that the practical upper limit to the usable storage is established by the number of weekend hours available for pumping. If, in the case of the example project, a maximum of 20 hours of equivalent full-discharge pumping is available on weekends, it can be seen from Figure 7-6 that weekday generation will be limited to 8.3 hours per day.

(7) By estimating the number of night-time pumping hours and assuming an average cycle efficiency and charge/discharge ratio for the plant, preliminary storage requirements can be estimated for various weekday generation requirements. These storage requirements represent the minimum storage needed to follow the specified operating cycle. It is usually desirable to provide some additional storage to cover for evaporation losses and reservoir leakage, for reserve, and to provide operating flexibility (see Sections 6-7j(3) and (4)).

(8) Once the equivalent number of hours of full-load generation is established, the specific storage requirement (in acre-feet) for a given site can be estimated with the following adaptation of the water power equation:

$$\text{Storage (AF)} = \frac{976(MW)t_s}{He_g} \qquad \text{(Eq. 7-2)}$$

where: MW = plant capacity in megawatts
t_s = storage requirement in hours of equivalent full-load generation
H = average gross head in feet
e_g = generating efficiency, including head losses (see Section 7-2j)

Figure 7-5 shows the variation of reservoir storage requirements versus head based on a required capacity of 1000 MW, a 14 hour storage requirement, and an average generating efficiency of 83 percent. The storage requirements for a specific site can be defined more precisely using a sequential streamflow routing analysis (see Section 7-3c).

(9) The above analysis is intended only to develop preliminary storage requirements for a given plant size and operating cycle. The final determination of storage requirements will be based on economics and other factors, and would include testing of the plant's operation under a range of simulated system operating conditions (see Section 7-5). A range of reservoir sizes should be examined for each plant size. This analysis should be done very carefully, and allowance

should be made for unanticipated operating conditions. Operating experience with some of the earlier pumped-storage projects constructed in the United States suggests that storage requirements were estimated too conservatively, and that additional storage could have added significantly to the usability of the capacity.

e. Plant Size.

(1) System requirements and site economics are major factors influencing plant size. The general process outlined in Section 6-2 can serve for identifying a range of potential plant sizes. For the reasons outlined in Section 7-2b(6), off-stream pumped-storage installations are typically large, with many falling in the 1000 to 2000 MW range. Site characteristics (i.e. low heads or limited reservoir storage) and system requirements sometimes dictate smaller plants, but 300 MW appears to be the lower limit among plants of this type constructed in the United States in the past 20 years.

(2) Some of the early, smaller plants were constructed to meet the needs of individual utilities. More recently, it has been possible to take advantage of economy of scale by constructing plants to meet the joint requirements of several utilities, or even entire power pools. Selection of the appropriate range of plant sizes to be considered should be made in consultation with the regional PMA, FERC, and local utilities.

f. Heads.

(1) Pumped-storage projects have been constructed to develop heads ranging from less than 100 feet to more than 2000 feet, but most of the projects at the low end of this range are either multiple-purpose projects, pump-back projects, or special types of projects. The minimum practical head for an off-stream pumped-storage project using reversible units is generally around 300 feet, with higher heads being preferred.

(2) A variety of machine types are available for pumped-storage applications. The type used for a given installation is generally dictated by the available head. In the 300 to 1600 foot range (and perhaps up to 2000 feet), the single-stage reversible Francis pump-turbine is usually the best choice. Above this head range, multi-stage units, or separate pumps and turbines should be considered, although pump-turbine technology is advancing to the point where reversible single-stage Francis units may be able to accomodate heads of greater than 2000 feet. For low head installations, several types of reversible pump-turbine are available, including bulb, vertical Kaplan and propeller, and Francis, the effective ranges of each type

corresponding generally to those shown on Figure 2-35 for the corresponding turbine type.

(3) The design of a reversible pump-turbine represents a compromise between efficient pumping operation and efficient turbine operation. As a result, the head range in which a reversible unit can operate relatively efficiently as both a pump and a turbine is rather limited. Since a high cycle efficiency is usually required for pumped-storage to be cost-effective, pumped-storage projects are normally designed to operate over a relatively narrow head range. A survey of major U.S. off-stream pumped-storage projects shows that the ratio of minimum to maximum head falls in the range of 0.8 to 0.9 (and preferably 0.85 or greater). It is recommended that head fluctuations be limited to this range wherever possible.

(4) Wider head ranges are possible, and in fact may be required in the case of (a) multiple-purpose projects with pump-back and/or (b) off-stream pumped-storge projects that use multiple-purpose storage projects as lower reservoirs, but certain penalties must be accepted. At the high end of a wide operating head range, both pumping efficiency and pumping discharge capacity fall off substantially, reducing the amount of water that can be pumped back during the available off-peak pumping hours. At the low end of the head range, turbine output and turbine efficiency are reduced markedly, limiting the amount of power that can be produced. At both ends, the machinery will tend to run roughly, with all of the attendent vibration problems.

(5) At pump-back projects with relatively wide head ranges, operating conditions are often such that (a) pumping is not required during periods when the head is at the high end of the range (i.e., when the reservoir is full or nearly full), and (b) the project operates only infrequently in the low end of the range, where turbine output is limited. A satisfactory operation can sometimes be achieved if it is possible to obtain reversible units that will operate efficiently under these particular conditions. Installing a mix of reversible units and conventional turbines and/or units designed to operate at different head ranges also may help to effectively utilize the power potential of projects of this type.

(6) Because of the complexity of pump-turbine design characteristics, it is suggested that hydraulic machinery specialists from one of the Hydroelectric Design Centers (Section 1-7) be consulted at an early stage in the planning process to help determine what type of pump-turbine installation and what type of power operation is most suitable for a given site.

g. Pump-Turbine Performance.

(1) Reversible units operate somewhat differently from conventional turbines. Operating in the generating mode is similar to conventional turbine operation, in that output can be varied by varying the gate opening. However, as a practical matter, units are usually operated as close to the point of best efficiency as possible. In the pumping mode, the unit operates at the gate opening that allows the most efficient operation for a given head.

(2) Figure 7-7 shows some of the characteristics of a typical Francis pump-turbine design, adapted from data presented in Volume 3 of EPRI EM-304 (12). This design is shown as being applied to a project with an operating head range of 730-820 feet (a ratio of minimum to maximum head of 89 percent). It is assumed in this case that the unit will be rated at the minimum operating head (when generating) of 730 feet. The full-gate discharge at this head would be about 3580 cfs and the overall generating efficiency (e_g) would be about 82 percent. The rated generating capacity would therefore be

$$kW = \frac{QHe_g}{11.81} = \frac{(3580\text{ cfs})(730\text{ feet})(0.82)}{11.81} = 180\text{ MW.}$$

(3) Note from the upper portion of Figure 7-7 that the pumping discharge at that head would be about 2930 cfs, substantially less than the generating discharge. The lower portion of Figure 7-7 shows that, at this head, the pumping efficiency (e_p) of about 87 percent is higher than the generating efficiency. However, since the pumping load requirements are inversely proportional to efficiency, the pump motor size at rated head will be somewhat larger than the generator requirement.

$$kW = \frac{QH}{11.81\ e_p} = \frac{(2930\text{ cfs})(730\text{ feet})}{(11.81)(0.87)} = 208\text{ MW.}$$

(4) The application of this runner design to the 730-820 foot operating head represents a typical application for an off-stream pumped-storage project. The pump discharge is less than the generating discharge throughout the head range, and the pumping efficiency is somewhat greater than the generating efficiency. The pumping load requirements are greater than the generator output at most heads. Thus, the pumping requirements establish the size of the motor-generator. Note that because the motor-generator is sized to meet pumping requirements, the unit is capable of generating somewhat more than 208 MW in the high end of the operating head range, but the

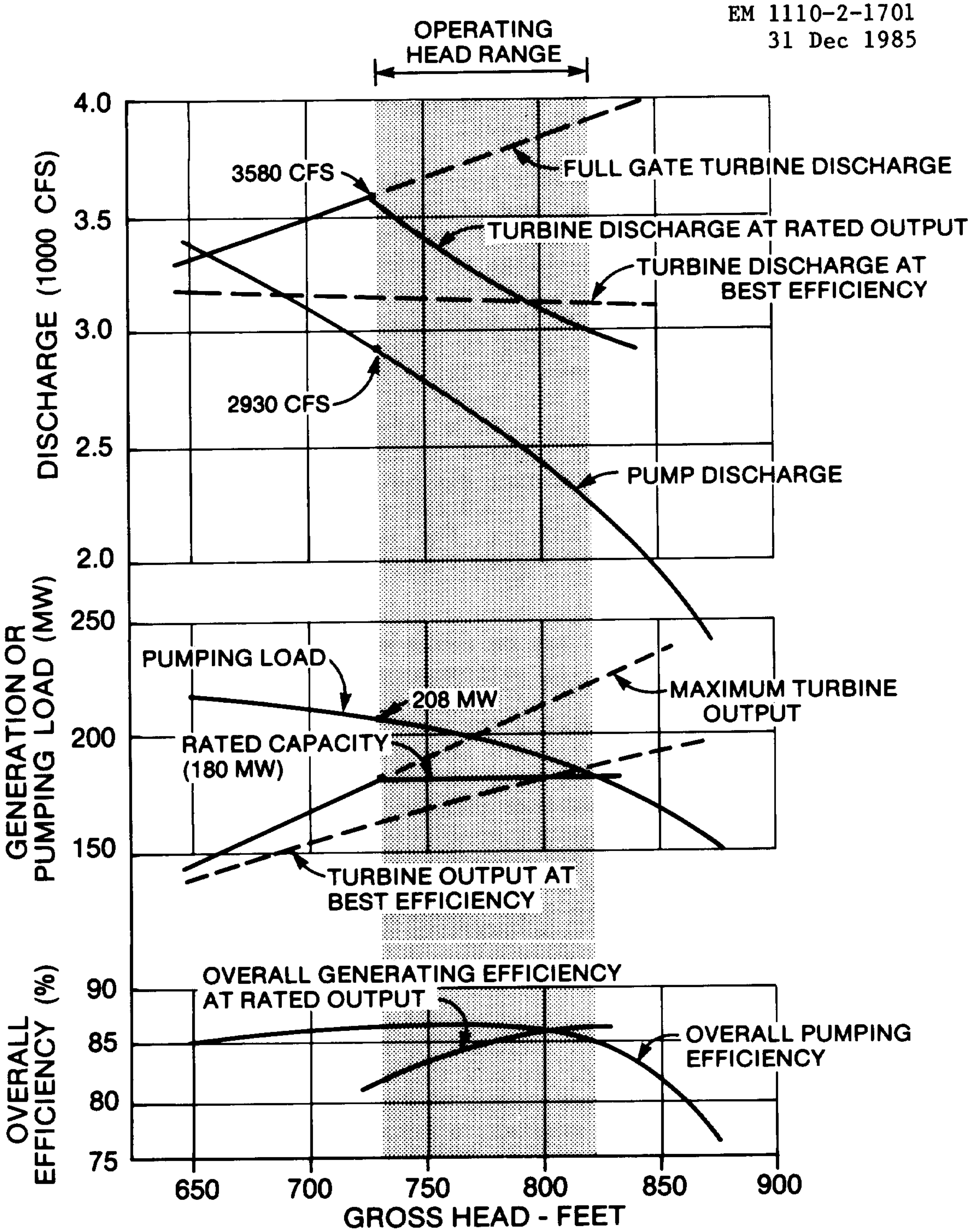

Figure 7-7. Performance curves for a typical pump-turbine runner showing application to a plant with an operating head range of 730-830 feet.

unit may in fact be operated at less than 208 MW in this head range in order to achieve best efficiency.

(5) This unit would have a charge/discharge ratio of about 1.1 (based on an average pumping load of about 200 MW and the rated generating capacity of 180 MW). At some projects, it may be important to have a higher pumping discharge relative to the generating discharge: i.e., where off-peak pumping time is limited and it is desired to move as much water in these hours as possible. In such cases, the unit would be designed to operate in the left-hand portion of the performance curve shown in Figure 7-7. Applying the same turbine design to a 650-730 foot operating head range would illustrate this approach (see Figure 7-8). At a rated head of 650 feet, the generating capacity would be limited to about 140 MW, but in the low end of the head range, the pumping discharge would equal or exceed the full gate generating discharge (3400 cfs versus 3300 cfs). However, to obtain this type of performance, the machine cost per kilowatt of generating capacity would be higher than for the original example (see Section 7-2k).

(6) Conversely, there may be cases where generating performance is more important than pumping performance. This might be the case at a pump-back project where the units would operate in the generating mode most of the time. Applying the turbine design in Figure 7-7 to an operating head range of 775-870 feet would achieve this objective (see Figure 7-9). At a rated head of 775 feet, the generator capacity (200 MW) would exceed the maximum pumping requirements (195 MW), and thus the generating requirements would dictate the size of the motor-generator. The generating efficiency would be somewhat higher than in the previous cases, and the machine costs per kilowatt of generating capacity would be relatively low. However, the pumping performance would be poor, in terms of both efficiency and pumping rate, and the unit would probably run roughly when pumping at the upper end of the head range.

(7) These examples are intended to illustrate how the performance of a pumped-storage project can be modified through the selection of the pump-turbine runner design and in rating that unit. As with conventional hydro studies, a detailed analysis of pump-turbine design is not necessary in the early stages of project planning. However, since pump-turbine selection can have a major impact on project performance and project economics, it is important to enlist the services of hydraulic machinery specialists once planning advances to the detailed analysis of a specific site. In order to permit selection of the proper unit, it will be necessary to define the operating characteristics of the project: (a) the operating cycle (required hours of generating and the available pumping hours), (b) the operating head range, and (c) any special

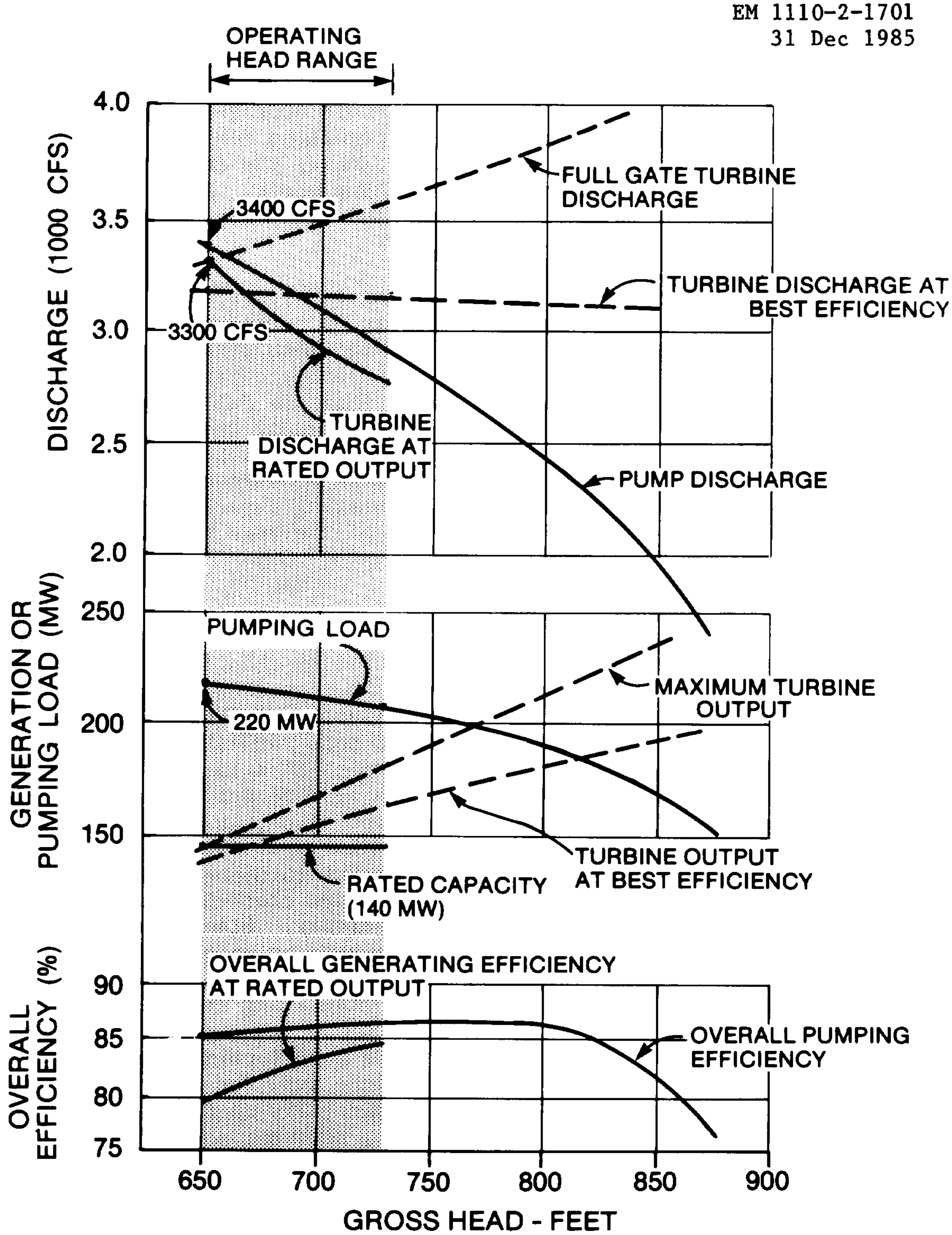

Figure 7-8. Application of pump-turbine shown in Figure 7-7 to a plant with an operating head range of 650-730 feet.

operating considerations. The special operating conditions could include limited pumping time, limited reservoir storage, operating characteristics of the lower reservoir if regulated for other purposes, and, in the case of pump-back projects, the relative amounts of time operated in the pumping and generating modes. Information should be provided for both design (must-run) and normal (economic dispatch) operating conditions.

h. Rated Capacity. A number of different approaches have been used to select the rated capacity of off-stream pumped-storage projects. However, for planning purposes, the most straightforward approach is to base the project's rated generating capacity on the normal minimum head. This helps to insure that the full rated capacity can be delivered by the plant regardless of pool elevation. In many cases, however, pumping requirements will dictate that a larger motor-generator be installed than would be needed to meet generating requirements. As a result, generating capacity may exceed the nominal rated capacity in the high end of the head range.

i. Plant Operating Characteristics.

(1) As noted in Section 7-2g(1), the output of reversible units operating in the generating mode can be varied by changing the wicket gate openings, thus varying the amount of water passing through the unit. Therefore, reversible units are physically capable of operating on automatic generation control in order to help regulate system loads. However, this type of operation results in a loss in efficiency (see Section 7-2j), and because water must be pumped using thermal plant generation to support this generation, the cost penalty for operating at reduced efficiency is not always acceptable. Operating to follow load also tends to increase maintainence requirements. Hence, most off-stream pumped-storage plants are block-loaded, operating at or near the point of best efficiency. Plant output can be adjusted to some degree by varying the number of units on line. There are, however, some systems where the resource mix is such that pumped-storage can be used effectively for regulating system loads.

(2) Starting and stopping a reversible pump-turbine when operating as a turbine is similar to the procedure used for a conventional unit. The unit is brought up to speed by partially opening the wicket gates. Starting the pump-turbine as a pump, however, poses special problems which must be examined in detail for each individual project. The more commonly considered starting methods include the following:

> full or reduced voltage across-the-line starting of the main unit as an induction motor: the starting current is obtained from the main transformers and damper windings which are built into the motor generator. This starting

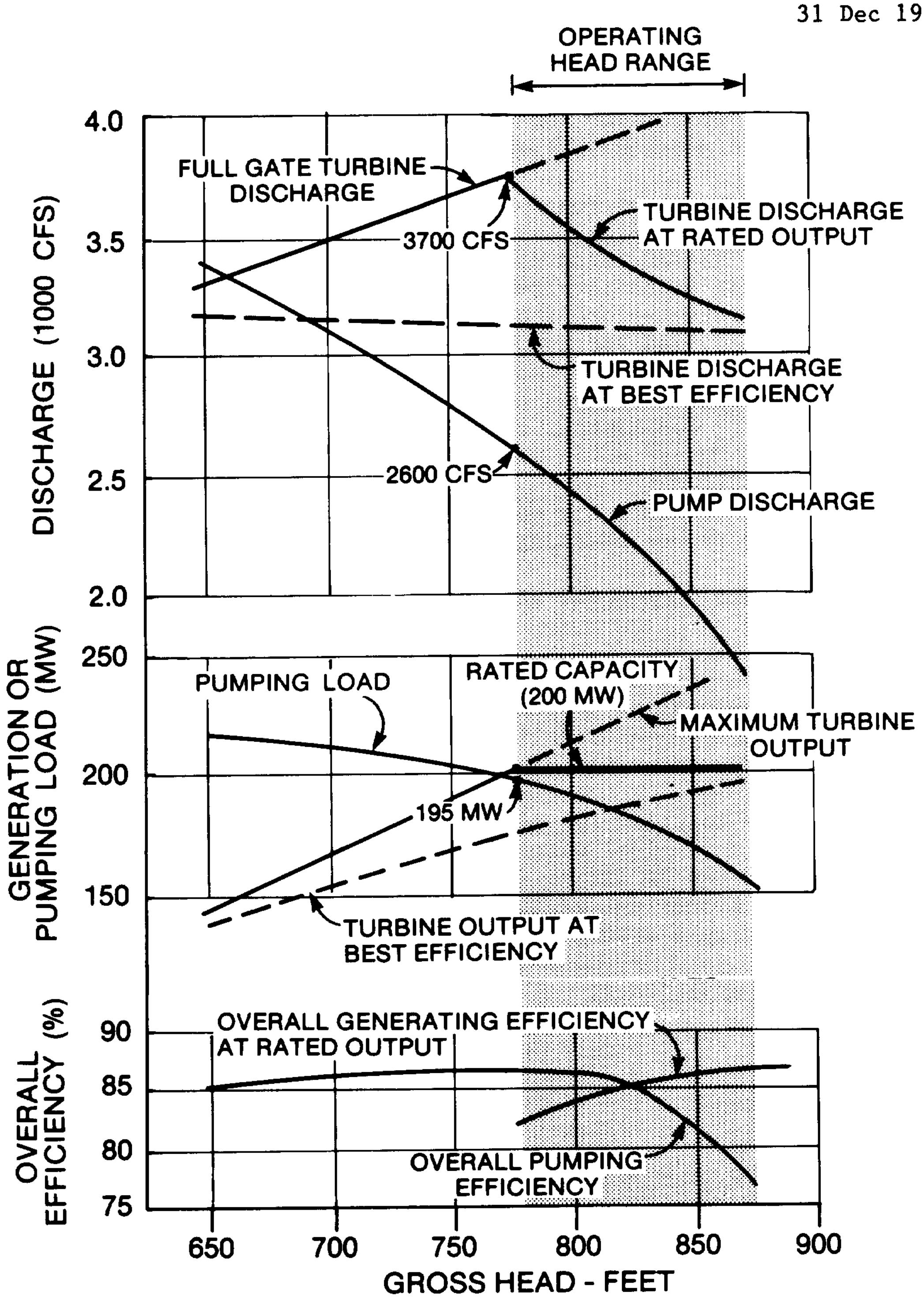

Figure 7-9. Application of pump-turbine shown in Figure 7-7 to a plant with an operating head range of 775-870 feet.

method can produce system disturbances due to the large kVA inrush. For this reason, it is normally limited to units of 30 MW or smaller for full-range starting and units up to 100 MW for reduced voltage starting.

synchronous or "back to back" starting: this requires that a separate prime mover (a turbine or another reversible unit) be connected electrically to the unit to be started. Both of these machines must be stopped and isolated from the system before starting. The prime mover is then started, and the pump turbine also starts in order to maintain an equal frequency. The speed of the prime mover is slowly increased until both units are at synchronous speed. Synchronous starting can also be accomplished with a small "pony" motor attached to the reversible unit shaft.

During starting as pump, the water level is normally depressed below the impeller to reduce starting torque.

(3) Typical turnaround and starting times for reversible units are as follows:

- from pumping to full-load generation . . . 2 to 20 minutes
- from generation to pumping . . . . 5 to 40 minutes
- from shut-down to full-load generation . . 1 to 5 minutes
- from shut-down to pumping . . . . 3 to 30 minutes

These times are to allow for deceleration of the unit, switching of electrical and mechanical circuits, and acceleration in the opposite direction. Because of limitations in control facilities or in the mechanical and electrical arrangement of the plant, it is frequently not possible to turn around more than one or two units at a time.

j. Cycle Efficiency.

(1) Cycle efficiency accounts for all losses in the operating cycle except transmission losses, and the reciprocal of the cycle efficiency represents the number of kilowatt-hours of pumping energy required to obtain one kilowatt-hour of generation. This value includes water passage head losses as well as pump, turbine, motor, generator, and transformer losses. In the past, a cycle efficiency of 67 percent has been used in planning studies. However, experience with plants constructed in the 1970's suggests that higher efficiencies can be achieved. In Volume 3 of EPRI EM-264 (12), representative ranges of cycle efficiency and their respective component efficiencies are presented (Table 7-3). The "high" values represent unconfirmed extrapolation of recent experience, but it is expected that overall cycle efficiencies as high as 75 percent can be

TABLE 7-3
Components of Cycle Efficiency

	Representative Ranges, %	
Pumping	Low	High
Motor and transformer	97.5	98.5
Pump	91.5	92.5
Water passages	96.5	98.5
Total	86.0	90.0
Generating		
Water passages	95.5	97.5
Turbine	89.0	92.5
Generator and transformer	97.5	98.5
Total	83.0	89.0
Allowance for Operation Under Other than Optimum Efficiency	92.0	98.0
Overall Cycle Efficiency	66.0	78.0

achieved in some cases. For planning purposes, it is suggested that a 70 percent cycle efficiency be used, which would be comprised of an overall pumping efficiency of 85 percent and an overall generating efficiency of 82 percent.

(2) The 70 percent cycle efficiency includes head loss allowances of about three percent for pumping and two percent for generating. Once the tentative penstock diameter has been established, more specific head loss values can be determined, and adjustments can be made to the overall efficiency values. In making sequential routing studies, it may be desirable to remove the head losses from the efficiency values and treat them separately.

(3) The pumping and generating efficiency values presented in the upper part of Table 7-3 represent operation at best efficiency. An "allowance for operation under other than optimum conditions" has also been included in the overall cycle efficiency to account for the

fact that the units must at times be operated under less than optimal loadings. For plants operated for load-following (see Section 7-2i), this component would be substantially lower. Existing plants operated in this mode exhibit overall cycle efficiencies on the order of 50 percent.

(4) The cycle efficiency values discussed above do not account for natural inflow to the upper reservoir or reservoir losses due to leakage or evaporation. In some cases, these quantities may be so small that they can be ignored, but they should be checked during the feasibility analysis and accounted for if necessary.

k. Charge/Discharge Ratio.

(1) The charge/discharge ratio for a pumped-storage unit is the ratio of the average pumping load (in megawatts) to the unit's rated capacity (see page C-4 of Volume 3 of reference (29)). Ratios for existing off-stream plants typically fall in the 0.9 to 1.3 range, with values as high as 1.4 being obtainable. A high value is achieved when a runner design is selected in which the average pumping discharge over the operating range is close to the average generating discharge. The charge/discharge ratio can be approximated by dividing (a) the ratio of average pumping discharge to the average generating discharge, by (b) the overall cycle efficiency. Thus, when the ratio of the average pumping discharge to the average generating discharge is 1.00, and the average cycle efficiency is 70 percent, the charge/discharge ratio will be (1.00)/(0.70) = 1.4.

(2) A high charge/discharge ratio is desirable because a maximum amount of water can be pumped during available off-peak hours, thus increasing on-peak generation time and/or reducing the carryover storage requirements (see Section 7-2d). However, this advantage comes at the expense of a slightly lower cycle efficiency and higher equipment costs (a larger runner and motor-generator will be required, compared to a unit having the same rated generating output but a lower charge/ discharge ratio). The average charge-to-discharge ratio for selected existing U.S. plants is about 1.1, and it is suggested that this value be used for planning studies. An exception might be where upper reservoir storage space is physically constrained or very costly, in which case a higher value could be assumed. Normally, detailed analysis of the charge/discharge ratio would be deferred until the project design stage.

l. Reliability and Availability.

(1) According to statistical data maintained by NERC, the forced outage rate for pumped-storage plants averages about 16 percent (27). However, this value is not suitable for computing an average annual

availability factor, because it is based on a relatively small number of operating hours per year. For purposes of developing an average annual availability factor (excluding maintenance) that is comparable with availability factors for non-peaking powerplants, an annual forced outage rate of seven percent was estimated (see Section 0-2d). This rate takes into consideration successful start ratios, number of outage hours per year, and other factors in addition to the NERC forced outage rate.

(2) The seven percent value is still higher than for conventional hydro plants, but this should be expected because pumped-storage units are more complex both electrically and mechanically, and they are typically involved in frequent start-ups and shutdowns, which put more stress on the equipment. Planned and other scheduled outages for maintenance typically require about five and a half weeks per year, which results in the following average availabilities:

- availability excluding maintenance outages - 93.0 percent
- availability including maintenance outages - 85.5 percent

m. Size and Number of Units. Whereas the size and number of units at a conventional hydro plant are often influenced by streamflow conditions (range of expected flows, minimum flow requirements, etc.), the size of the units at a pumped-storage plant is influenced predominantly by load conditions. Just as with conventional hydro plants, minimum plant costs are usually achieved for a plant of a given installed capacity with the minimum number of units of the largest practical size. However, offsetting the economy of scale are power system operating requirements. For maximum flexibility in dispatch of generation to meet loads, smaller units are desirable. Likewise, smaller units permit more flexibility in utilizing available low-cost pumping energy in the off-peak hours. Units for recent off-stream pumped-storage projects tend to be the largest size units that can effectively be used in the load, mostly falling in the 250 to 380 MW range.

n. Plant Factor.

(1) It is sometimes difficult to predict the plant factor of a pumped-storage project, because operation is a function of the generation mix, the relative fuel prices of the different types of projects in that mix, the load shape, and the reserve margin, all of which have been subject to change in recent years. In some cases, plants have operated at a higher plant factor than expected, while in other cases, the opposite has been true.

(2) Plant factor is also a function of reservoir storage, because the larger the amount of carryover storage, the larger the

theoretical maximum amount of generation that can be produced. The maximum plant factor (PF_{max}) for a weekly cycle off-stream pumped-storage project could be estimated by the following equation:

$$PF_{max} = \frac{t_s + 4\ t_p E_c C_t}{168} \qquad \text{(Eq. 7-3)}$$

where: t_s = reservoir storage, in hours of equivalent full-load generation
t_p = equivalent hours of pumping at full capacity per weekend
E_c = overall cycle efficiency
C_t = charge/discharge ratio

For a daily cycle plant, the equation would be reduced to

$$PF_{max} = \frac{5t_p E_c C_t}{168}.$$

These equations are based on the plant operating five days a week and all reservoir storage being restored over the weekend. However, the typical pumped-storage project does not normally operate at its maximum capacity throughout the year. Variations in the shape and magnitude of the daily load over the course of the year, the cost and availability of alternative peaking resources, and the cost of pumping energy all influence the amount of time a pumped-storage project is used. In addition, a portion of the plant is unavailable part of the time due to forced outages and scheduled maintenance outages.

(3) A survey of recent operating experience shows that most pumped-storage plants in this country operate at annual plant factors ranging from about 40 to 80 percent of the maximum plant factor, with some as low as 5 percent. This corresponds to annual plant factors of 6 to 16 percent for most plants, with two plants having plant factors on the order of one percent. This wide range illustrates the wide variety of system conditions under which these plants operate. Since the average annual plant factor is so strongly influenced by power system characteristics, it can be estimated accurately only by using system simulation studies (see Sections 7-5e through g). However, for very preliminary studies, an average plant factor of 60 percent of the theoretical maximum plant factor can be assumed for plants operating in most power systems. Operating experience in the WSCC reliability region, however, shows too much variation to permit use of a generalized value even in preliminary studies.

(4) Another point to consider when estimating plant factor is that a power system is dynamic. All of its characteristics change with time. Since a pumped-storage plant's operation is tied so closely to the system's characteristics, its plant factor could change considerably over its service life, in response to changing system characteristics. It is essential that these changes are accounted for in the project analyses (see Sections 7-5b and e).

o. Lower Reservoir Characteristics.

(1) A variety of water bodies can be used as lower reservoirs for pumped-storage projects:

- natural lakes
- open rivers
- existing pondage projects
- existing power storage projects
- existing multiple-purpose storage projects
- specially constructed lower reservoirs
- the ocean

In a few instances, natural lakes or open river reaches have been used as lower reservoirs (Ludington uses Lake Michigan, for example), but environmental and public use impacts often discourage consideration of natural lakes and open river reaches. New lower reservoirs can be designed specifically to meet the requirements of the pumped-storage operation. However, to avoid the environmental impact of constructing new reservoirs, siting pumped-storage projects adjacent to existing projects is often given serious consideration. Such projects must be examined carefully, because existing reservoirs do not always make suitable lower reservoirs for pumped-storage projects.

(2) At pondage projects, pumped-storage operation is superimposed on the existing pondage operation, and this may may in some cases increase pondage requirements above the existing reservoir capacity. To obtain the additional pondage, it may be necessary to raise the existing dam or otherwise modify the structure. In other cases, superimposing pumped-storage operation on the existing operation may reduce pondage requirements. Operation of the existing pondage project under flood flow conditions must also be examined, in order to determine if the operating head of the pumped-storage project is reduced significantly. Hourly sequential routing studies must be made in order to evaluate these operations (see Sections 7-3c and 7-4).

(3) Pondage requirements are not usually a problem where existing seasonal storage projects are used as lower reservoirs. Here, the major problem is usually the range of pool fluctuation. At

some storage projects, existing operations may require seasonal pool fluctuations of 100 feet or more. When combined with daily/weekly cycle fluctuations in the upper reservoir, the resulting head range may exceed the normal operating range for reversible units (Section 7-2f). A wide range of lower reservoir fluctuations may also require unacceptably low runner settings (see Section 7-2q(3)). In some cases, the latter problem can be alleviated by not pumping when the reservoir is at low elevations. However, this will impact the pumped-storage project's dependable capacity if low pool elevations occur frequently, or if they occur during the peak demand season.

p. Penstock Head Losses.

(1) Penstocks represent a significant portion of the costs of an off-stream pumped-storage project (10 to 30 percent), and detailed analyses must be made during the advanced stages of planning to determine the most cost-effective penstock design. However, in the initial stages of planning, some general guidelines can be applied to develop an approximate estimate of head loss. The rated generating discharge can be estimated using the water power equation:

$$\text{Generating discharge (cfs)} = \frac{11.81(\text{kW})}{He_g} \qquad \text{(Eq. 7-4)}$$

where: kW = installed capacity in kilowatts
H = gross head in feet
e_g = overall generating efficiency (including an estimated head loss)

(2) For pump-back projects, heads will generally be relatively low; the heads for most of the projects listed in Table 7-2 are less than 400 feet. For projects in this head range, the procedure outlined in Section 5-61 is satisfactory for developing a preliminary estimate of penstock size and head loss. Velocity (V) can be defined in terms of the generating discharge value (Q_g), which was computed using Equation 7-4, and penstock diameter (D), which is unknown:

$$V = \frac{4Q_g}{\pi D^2} \qquad \text{(Eq. 7-5)}$$

This value would then be substituted into Equations 5-6 and 5-7, and the two equations solved simultaneously to obtain the penstock diameter (D).

(3) Once the penstock diameter has been determined, the head loss would be estimated using Equation 5-6. If the resulting head

loss is substantially greater than that included in the overall generating efficiency in Equation 7-4, a second iteration could be made, incorporating the head loss value obtained in the first iteration in the overall generating efficiency.

(4) Off-stream pumped-storage projects tend to have considerably higher heads, ranging from 600 feet up to 2000 feet or more. For projects operating at these heads, the preliminary penstock size should be based on a maximum allowable head loss of three to five percent of the average gross head. The penstock diameter could then be estimated using the Scobey equation (Equation 5-6), the penstock length, the rated generating discharge from Equation 7-4, the average gross head, and the assumed maximum allowable percent head loss. The overall generating efficiency used in Equation 7-5 should be based on penstock head losses that are equal to the assumed maximum allowable percent head loss. For example, the 82 percent overall generating efficiency suggested in Section 7-2j incorporates a penstock head loss of about 3.5 percent. If a maximum allowable penstock loss of 5.0 percent is to be used for developing a preliminary estimate of penstock diameter, an overall pumping efficiency of (0.82) x (0.95/0.965) = 81 percent should be used in Equation 7-4.

(5) Typically, tunnel diameters would not exceed 40 feet, so multiple tunnels would be used for large discharges.

q. Other Factors.

(1) Transmission Costs and Losses. Just as with conventional hydro plants, transmission losses must be accounted for in the benefit analysis (see Sections 8-6 and 9-5g). An important difference, however, is the fact that transmission energy losses occur in both the pumping and the generating operations. Because the value of these losses can be substantial, particularly when pumping, and because of the high cost of constructing transmission lines to remote sites, off-stream pumped-storage projects located at a distance from load centers and/or the sources of pumping energy are seldom economically attractive.

(2) Reservoir Drawdown. An inherent characteristic of daily/weekly off-stream pumped-storage projects is that short-term reservoir fluctuations occur on a regular basis. During peak demand periods, it is not unusual for a large part of the reservoir storage to be drafted and then refilled during the course of the week (or within a 24-hour period in the case of daily cycle plants). Upper reservoirs often must be constructed in confined areas, and as a result, they have relatively steep storage-elevation characteristics. Fluctuation ranges are correspondingly larger, with some projects having normal

operating ranges of as much as 160 feet. Such wide fluctuation ranges can cause embankment and shoreline stability problems, as well as significant environmental and public safety impacts. In fact, it is often necessary to fence off upper reservoirs in the interest of public safety. Another problem with large fluctuations is that they may create a head range that exceeds the normal operating range for reversible pump-turbine units. Fluctuation ranges can be reduced by providing more dead storage, thus moving up to a flatter portion of the storage-elevation curve. However, the reduced fluctuations are usually achieved at the expense of increased embankment costs. Where possible, upper reservoirs should be designed such that weekly fluctuation ranges do not exceed 100 feet. Larger fluctuations may be permissible in some cases, but the impacts of such fluctuations must be carefully examined. Because lower reservoirs typically have larger surface areas, fluctuation ranges are usually smaller. However, because these reservoirs have larger shorelines and are usually more accessible to the public, the impacts of such fluctuations could be just as serious. Another consideration is the fact that lower reservoirs are often operated for other purposes in addition to pumped-storage operation. Superimposing the pumped-storage regulation on top of operation for other purposes could result in either larger or smaller fluctuation ranges (see Sections 7-3c(3) and 7-4c).

(3) Submergence. In order to avoid cavitation during pumping operations, reversible units must be set lower than conventional turbines. The distance the runner centerline must be set below normal minimum tailwater elevation is a function of head, rotational speed, and other factors. Submergence values for reversible units can range from 30 feet to 100 feet or more, depending on the site characteristics and the runner design. For preliminary planning purposes, a minimum of 50 feet can be assumed for high head off-stream projects. During advanced studies, specific submergence requirements should be determined in consultation with hydraulic machinery specialists from one of the Hydroelectric Design Centers. Submergence characteristics often make underground powerhouses more attractive than above-ground structures, because higher speed units with greater submergence requirements can be used. Higher speed units are physically smaller, requiring a smaller, less costly powerhouse structure.

7-3. Overall Study Procedure.

a. Introduction.

(1) Following is an outline of the overall procedure for analyzing an off-stream pumped-storage site. A study of a specific site often originates as a result of a screening study. System planning studies may indicate a need for a block of peaking power that

could be met with off-stream pumped storage. The first step would be to make a screening study to evaluate alternative sites in the area which might be capable of providing the required block of capacity (see Section 7-7b). The most promising site (or sites) would then be subjected to the analysis described below. In such an analysis, the approximate plant size would usually by given, although a limited range of alternative plant sizes would be tested to insure that the site is developed economically.

(2) A pumped-storage study could also be initiated to examine a specific promising site. Such a study might be made, for example, to determine if an off-stream pumped-storage project could be developed and operated in conjunction with an existing hydropower or multiple-purpose project, which would serve as the lower reservoir for the pumped-storage project. In such a study, a wide range of plant sizes might be examined in order to determine the optimum overall development.

(3) In the procedure outlined below, it is assumed for the sake of simplicity that the objective is to develop a site to meet a specific capacity requirement (1000 MW, for example). The same general procedure would be followed in a study to determine the optimum plant size for a given site, except that a wider range of alternatives would be carried through the economic analysis stage.

(4) As with other portions of this manual, emphasis has been placed on the power studies that are required to evaluate a pumped-storage project. Environmental, institutional, and socio-economic studies and analysis of other potential project purposes are equally important, and they must be closely coordinated with the power studies. The Planning Guidance Notebook (49) provides information on these aspects of the planning process and how to integrate the power studies in the overall project planning program. Geologic studies must also be undertaken in parallel with the power studies, in order to determine if the reservoirs can hold water and if the site is suitable for the construction of impoundment structures, tunnels, and either an underground or surface type powerhouse.

b. Define Site and Plant Characteristics.

(1) Develop Tentative Site Layout. Make a preliminary layout of the project, including upper and lower reservoir location, powerhouse location, and penstock and discharge tunnel alignments.

(2) Define Operating Cycle. Determine the number of off-peak pumping hours available each week-night and the minimum number of on-peak generating hours required each weekday for the capacity to be dependable (see Section 7-2c).

(3) Estimate Storage Requirements. Given the operating cycle and Equation 7-1, estimate the minimum number of hours of storage required (see Section 7-2d). For the initial estimate, an overall cycle efficiency of 70 percent and a charge/discharge ratio of 1.1 can be assumed (see Section 7-2j and k). Storage requirements should also be estimated for at least two larger reservoirs. For example, if the minimum number of on-peak generating hours is 5 hours per day, storage requirements might also be estimated for reservoirs capable of supporting 6 and 7 hours per day.

(4) Define Characteristics of Lower Reservoir. If an existing reservoir is to be used, the normal maximum and minimum pool elevations must be identified so that the pumped-storage project's operating head range can be assumed. Storage-elevation characteristics must also be identified, and reservoir inflow and reservoir regulation characteristics must be defined. If a new lower reservoir is to be constructed, a storage-elevation curve must be developed and reservoir inflows must be determined for a representative historical period of record.

(5) Define Characteristics of Upper Reservoir. A storage-elevation curve must be developed for the upper reservoir. Evaporation and leakage losses must also be estimated, and natural inflows (if any) must be estimated.

(6) Estimate Reservoir Volume and Pool Elevations. Estimating the required reservoir volume is an iterative process. The first step is to make a preliminary estimate using the desired plant size, the hours of storage determined above, and Equation 7-2 (Section 7-2d). For this calculation, estimate the average gross head and use a generating efficiency (including head losses) of 82 percent (see Section 7-2j). Apply this volume to the storage-elevation curve for the upper reservoir (allowing for a reasonable amount of dead storage and some reserve storage capacity, if desired (see Section 7-2d)). Identify maximum and minimum pool elevations. Check these elevations to insure that the drawdown range is not excessive (see Section 7-2q(2)). If a new reservoir is to be used for the lower reservoir, calculate preliminary maximum and minimum pool elevations in the same way. Head losses can also be estimated using the procedures outlined in Section 7-2p. With this information, estimate a new average head, and recompute the required storage volume using Equation 7-2. If head losses are computed separately, they would be included in the average head, and a somewhat higher generating efficiency should be used (84 to 85 percent). This revised reservoir volume, along with revised maximum and minimum pool elevations, could be used for making initial reservoir cost estimates. A more precise estimate of reservoir storage requirements will be required for the detailed layouts and

cost estimates prepared in the final stages of planning, and this value would be obtained from sequential streamflow routing studies.

c. Sequential Streamflow Routing and Related Studies.

(1) Define Worst Case Operating Cycle. In order to make final estimates of reservoir storage volumes, discharges, and reservoir fluctuations, a sequential routing analysis must be made for the operating situation that puts the greatest stress on the reservoir. This would normally be a week when the project is operating to meet the design operating cycle under must-run conditions (see Section 7-2c). When the lower reservoir is operated to serve other functions, the worst case often occurs when it is at the upper part of its elevation range (i.e., when the head on the pumped-storage project would be at its minimum).

(2) Perform Worst Case Sequential Routings. Perform hourly sequential streamflow routing studies based on the worst case operating conditions (see Section 7-4). This analysis would consider operation of both the upper and lower reservoirs.

(3) Perform Other Sequential Routings. Perform additional sequential routings for other operating conditions, in order to define the full range of conditions under which the project would be expected to operate, typical as well as extreme. Typical pumped-storage loadings could be obtained from the production cost studies (see Section 7-5g). A range of lower reservoir operating conditions should also be examined. If the lower reservoir is a pondage project, a variety of streamflow conditions and pondage operations should be examined, in order to insure that adequate pondage is available to support both the pumped-storage and pondage operation. Operation under flood flow conditions should also be examined. If the lower reservoir is a multiple-purpose storage project, examine the operation of the pumped-storage project under the full range of reservoir operating conditions. Data from the hourly sequential routing studies would be used in turbine selection studies, project design, environmental analyses, and in evaluating impacts on lower reservoir functions. If the reservoir is a new impoundment, designed to serve only as a lower reservoir for the pumped-storage project, operation under a range of typical flow conditions should be examined. Also, it may be desirable to test alternative maximum pool elevations in order to determine the relative magnitude of pool fluctuations.

(4) Select Pump-Turbine Design. Once sufficient sequential routing studies have been done to identify the normal and extreme operating conditions, a tentative pump-turbine design would be selected in consultation with hydraulic machinery specialists from one of the Hydroelectric Design Centers. Unit size would also be

selected, considering power system operating requirements, project operating conditions, and economics.

(5) Compute Energy Content of Reservoirs. Production cost models often require that upper reservoir storage be specified in terms of energy content. Since models of this type typically incorporate an efficiency loss adjustment, the gross energy content would normally be specified.

$$\text{Reservoir Energy Content (gWh)} = \frac{MWt_s}{1000e_g} \qquad \text{(Eq. 7-6)}$$

where: MW = installed capacity in megawatts
t_s = hours of storage (Section 7-2c)
e_g = overall generating efficiency, including head loss

(6) Compute Dependable Capacity. Compute dependable capacity as described in Section 6-7j.

d. Economic Analysis.

(1) General. Off-stream pumped-storage projects are typically large compared to system loads, so in accordance with Section 2.5.6 of Principles and Guidelines (77), a complete load-resource analysis must be performed in order to define the need for the capacity (see Chapter 3). However, because the economics of pumped storage are so closely related to the power system's load and resource characteristics, the economic analysis and load-resource analysis must be performed together. Since pumped-storage benefits are sensitive to changes in load shape, system generation mix, relative fuel costs, and other system-related factors, all of which are subject to change over time, this analysis should be performed for a period extending ten to twenty years beyond the expected project on-line date. Following is a summary of the major steps involved in a combined economic/load-resource analysis. The details of each of these analysis are described in Section 7-5.

(2) Define Without-Project Conditions. This step includes defining the power system to be analyzed (see Section 7-5b(2)). Loads and load shapes for the system must be projected for at least ten years beyond the expected project on-line date, and projections of the expected generating resources must be developed for each of these years. New (non-hydro) generating resources would be scheduled to come on-line as needed to insure that peak loads will be met while maintaining an adequate reserve margin (see Section 7-5b). Operating characteristics and fuel costs must also be defined for each of these resources.

(3) Compute System Operating Costs for Without-Project Scenario. System operating costs (mostly fuel costs) would be computed for each year using an hourly production cost model (see Section 7-5d).

(4) Define With-Project Scenario. The without-project conditions would be modified such that the pumped-storage project would be scheduled to come on-line in lieu of an increment of new thermal capacity (Section 7-5e). Several on-line dates should be tested, the first of which would be the first year in which the load-resource analysis shows that the new capacity would be needed.

(5) Compute Pumped-Storage Energy Benefits. System operating costs would be computed with pumped-storage replacing the increment of thermal capacity (Section 7-5g). The difference in system operating costs between the system without pumped-storage and the system with pumped-storage would be the net savings in energy costs due to pumped-storage operation. The pumping energy costs can also be identified using the production cost model, and the sum of the net savings in energy costs and the pumping energy costs would equal the energy benefits attributable to pumped-storage (Section 7-5h).

(6) Compute Capacity Benefits. The capacity benefits would be the annualized capital costs of the increment of capacity replaced by the pumped-storage project, and they would be computed in the same way as for conventional hydro projects (Section 7-5i).

(7) Alternative Configurations. In a typical pumped-storage site evaluation, a number of alternative developments might be considered, including the following:

- alternative reservoir sizes
- alternative plant sizes
- alternative pump-turbine sizes
- alternative penstock sizes
- underground vs. above-ground powerhouses

Benefit analyses would have to be performed to test each of these alternatives.

(8) Other Sensitivity Analyses. It is often desirable to do additional sensitivity studies, to test such variables as alternative on-line dates, alternative real fuel cost escalation rates, alternative load growth rates, and alternative load shapes.

7-4. Sequential Routing Studies.

a. General. The sequential streamflow routing (SSR) studies described in Section 7-3c would be made using an hourly (or multi-hourly) SSR model. Section 6-9 provides some general information on hourly SSR studies. Input data that would be required in addition to that described in Section 6-9b is listed below. The HEC-5 model includes a special routine that is capable of analyzing both pump-back and off-stream pumped-storage projects. Section K-5 describes how HEC-5 would be applied to pumped-storage analysis.

b. Data Requirements.

(1) General. Following is a list of additional data required for hourly SSR studies of pumped-storage projects.

(2) Hourly Generation. Generation requirements for the pumped-storage project must be specified by hour for each week being examined. These values can be obtained from either the design operating cycle (Section 7-2c) or from production cost studies (Section 7-5g), depending on the operating condition being examined.

(3) Hourly Pumping Loads. Available off-peak pumping energy is also specified by hour for each week. These values are also obtained from either the design operating cycle or from production cost studies.

(4) Efficiency Values. Efficiency values must be specified for both pumping and generating. Initial studies could be based on typical fixed efficiencies (see Section 7-2j), which might include an allowance for penstock head losses. Once pump-turbine selection has been completed, efficiency versus head curves could be used, with penstock losses treated separately (see below).

(5) Head Losses. Head losses can be important in the analysis of pumped-storage projects, and where possible, it should be represented as a function of flow rather than a fixed value (see Sections 5-61 and K-3c(5)).

(6) Pumping Capacity. The rated pumping capacity for a reversible unit is often different (usually larger) than the generating capacity. When operating in the pumping mode, the units typically operate at the gate opening that gives best efficiency. Hence, they might operate at rated capacity only at the low end of the normal operating head range (see Figure 7-7), and of reduced capacity at higher heads. Where possible, it is preferable to specify pumping capacity as a function of head. When this is not possible, an average pumping capacity rather than a rated capacity should be specified.

c. Analysis of Storage Requirements. The procedure outlined in Section 7-3b is intended to provide only an approximate "starting" value based on some generalized assumptions. Hourly sequential streamflow routing studies must be made for the worst-case week (see Section 7-3c(1)), in order to develop a more precise estimate of the projects's reservoir storage requirements. The sequential routing will account for (a) hour-by-hour variations in head due to changes in reservoir elevation, (b) reservoir storage-elevation characteristics, (c) the performance characteristics of the pump-turbine, and (d) other factors. It is often necessary to test a range of operating conditions to insure that the worst-case scenario has in fact been identified. It may also be desirable to examine a range of less severe operating conditions in order to define the project's normal performance characteristics.

d. Analysis of Lower Reservoirs.

(1) When existing projects are used as lower reservoirs, the pumped-storage operation must be superimposed on the operation of the existing reservoir (see Section 7-3c(3)). In most cases inflow, discharge, and basic reservoir elevation data describing the operation of the existing lower reservoir can be obtained from historical data or from existing period-of-record SSR studies.

(2) In the case of pondage projects, it may be desirable to test alternative operations of the pondage project to optimize the combined operation of the pondage project and the off-stream pumped-storage project. When the lower reservoir is a pondage project that is one of a series of projects, the analysis would be more complex. For further information on this type of analysis, reference should be made to studies of the Richard B. Russell project (Savannah District) and to studies of potential pumped-storage projects located adjacent to mainstream Columbia River projects (North Pacific Division).

(3) When an existing seasonal storage project is being used as the lower reservoir, either the historical operating record or a period-of-record sequential routing (or both) should be examined, in order to identify the range and distribution of pool elevations. This is required to help define the pumped-storage project's head characteristics.

(4) When a new lower reservoir is to be constructed, the lower reservoir often operates as a reregulating reservoir, and minimum discharge and rate-of-change-of-discharge criteria must be developed to govern operation of the reservoir. For flood control projects, existing pondage projects, and new lower reservoirs, flood flows must be routed through the reservoirs to determine their impact on pumped-

storage project operation. This is because in many cases, flood operation defines the project's minimum operating head.

e. Unsteady Flow Analysis. When a pumped-storage project discharges into a relatively shallow lower reservoir, full-load pumping or generating can have a major impact on flow conditions in the immediate vicinity of the intake/discharge. Unsteady flow studies must be made to determine velocity conditions and their impact on other reservoir uses (such as navigation, recreation, and fish and wildlife). Models such as RMA-2 (91) are suitable for this purpose.

7-5. Economic Analysis.

a. Introduction. Section 7-3d outlines the general procedures used in economic analyses of pumped-storage projects. This section describes these steps in more detail, as well as some of the tools that are available for these analyses.

b. Define Without-Project Conditions.

(1) General. This step basically consists of making a year-by-year load-resource analysis for the period extending from the present to ten to twenty years beyond the expected project on-line date. It is necessary to extend the analysis into the future because pumped-storage benefits are a function of factors such as load shapes, load growth rate, resource mix, relative fuel costs, reserve margin and other system-related factors, many of which may change significantly with time. The difficulty with doing this type of analysis is that uncertainty is associated with all of these factors. One practical approach is to make an analysis based on the best estimate of expected conditions and to make sensitivity studies to test the effect of alternative assumptions on project economics. As planning continues, project economics should be reexamined periodically to determine if changing conditions will affect the project's feasibility or on-line date.

(2) Identify System for Analysis. The system to be included in the analysis should include those power systems that would be impacted by operation of the pumped-storage project. This would often include adjacent systems, in addition to those systems where the power would actually be marketed. The selection of the area to be analyzed should be made in consultation with the regional Federal Power Marketing Administration, FERC, and in some cases, the local utilities or power pool.

(3) Load Forecast. Sources of load forecasts are described in Chapter 3. Often, however, it is necessary to project loads beyond the available data. It is common to extend forecasts using the load growth rate assumed for the last 5 to 10 years of the available forecast period.

(4) Hourly Load Shapes. Hourly load shapes must also be developed. Generally, the only hourly load data available is recent historical loads. This data can be used, but care should be taken to insure that it is representative. Production cost models such as POWRSYM require hourly loads for an entire year. When a full year of data is not available, a full year can be generated using several representative weeks, as described in EPRI report EM-285 (15). This report also contains some typical weekly load shapes. Consideration should be given to modifying these load shapes so that they reflect expected changes due to factors such as load shape management. Omaha District has developed a technique for modifying load shapes to account for load management in their Gregory County pumped-storage project studies.

(5) Existing and Planned Resources. Data on existing generating resources and scheduled additions and retirements is usually available from the Energy Information Agency (EIA) and from the NERC Regional Reliability Councils (see Section 3-5b). Unfortunately, this data usually covers only the next ten years, which in many cases would not extend even to the projected on-line date for the pumped-storage project being studied. This requires that additional resources be scheduled to insure that peak loads are met and that adequate reserves are provided for each year in the period of study.

(6) Determine Resource Deficits. Existing and planned resources are compared to projected loads in order to determine future deficits (see Sections 3-3b and 3-10d). In computing deficits, loads should be increased by reserve requirements (use a 20 percent reserve margin when more specific data is not available). Figure 7-10 shows an example of such an analysis. Note that the figure shows the total capacity of existing and scheduled generating resources decreasing with time. This is due to retirements. In estimating retirement dates, it has been common to assume that thermal plants have operating lives of 30 to 35 years, although the trend seems to be toward longer service lives.

(7) Project Additional Resources. In order to fully describe the without-project scenario, it is necessary to schedule additional resources to cover projected deficits. The most likely mix of new resources can be determined using a generation expansion model (see Section 9-4a(3) and reference (33)). However, when such a model is not available, the most likely resource mix can be estimated using the

production cost model (PCM) that will be used for the pumped-storage energy benefit analysis. Several alternative mixes (70 percent coal/30 percent combustion turbine, for example) could be scheduled to fill projected deficits through the end of the period of analysis (see Figure 7-11). System energy costs would be determined for each year using the PCM. The total present value of the capital costs of the new plants (as they occur) and the year-by-year system energy costs (from the PCM) would then be determined for each mix, and the mix with the lowest total present value cost would be identified (see Figure 7-12).

(8) Selection of Most Likely New Resource Mix. In many cases, the least costly resource mix would be used as the without-project scenario. However, in some systems, prevailing utility policies or other factors may suggest a somewhat different mix. For example, many utilities avoid installing a large amount of combustion turbine capacity because of uncertainty over fuel prices and fuel availability. They will instead invest in cycling steam plants and

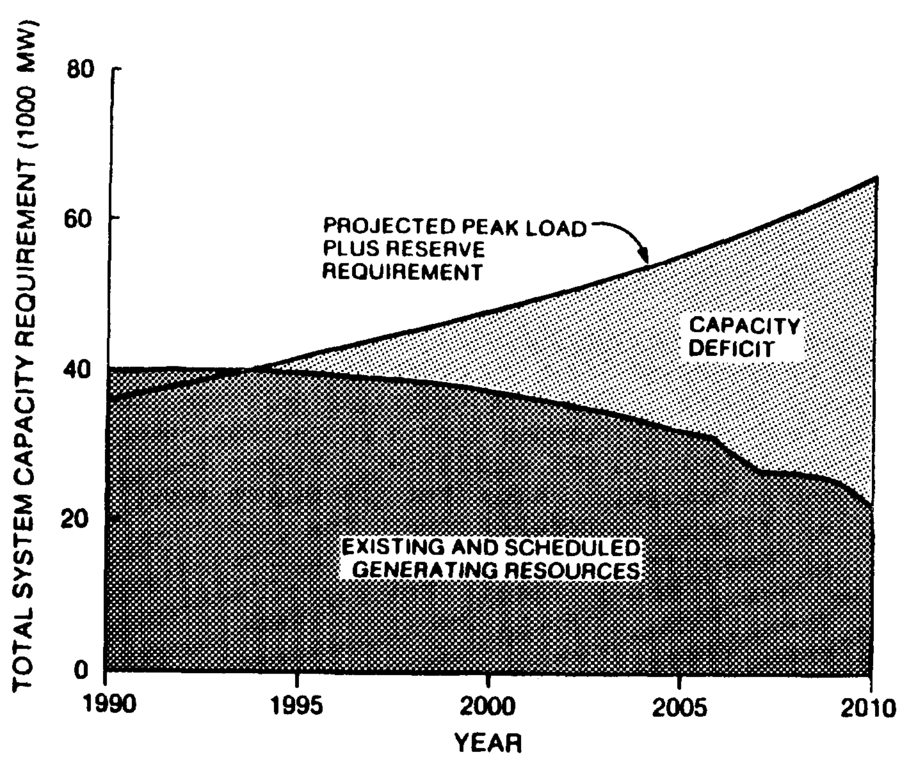

Figure 7-10. Projection of peak loads, resources, and capacity deficits

utilize older steam plants in order to meet reserve requirements. In the example based on Figure 7-12, the curve is relatively flat between 20 and 50 percent combustion turbines, indicating that costs are about the same for any mix in this range. To protect against fuel price escalation and fuel shortages, the regional policy might suggest that the most likely mix might be the mix in this range with the least amount of combustion turbine capacity (20 percent). While present value cost analysis should serve as the starting point in selecting the without-project resource mix, the regional PMA, FERC, and local utilities should also be consulted to insure that the mix approximates the most likely future condition as clearly as possible.

(9) Criteria for Analyzing Future Resource Mixes. Analyses of the type described above are typically done using an inflation-free discount rate of 3 to 4 percent. Note that this rate would be used only in the determination of the without-project resource mix; the current Federal interest rate would be used in the pumped-storage project benefit analysis. In order to avoid end effects, it is

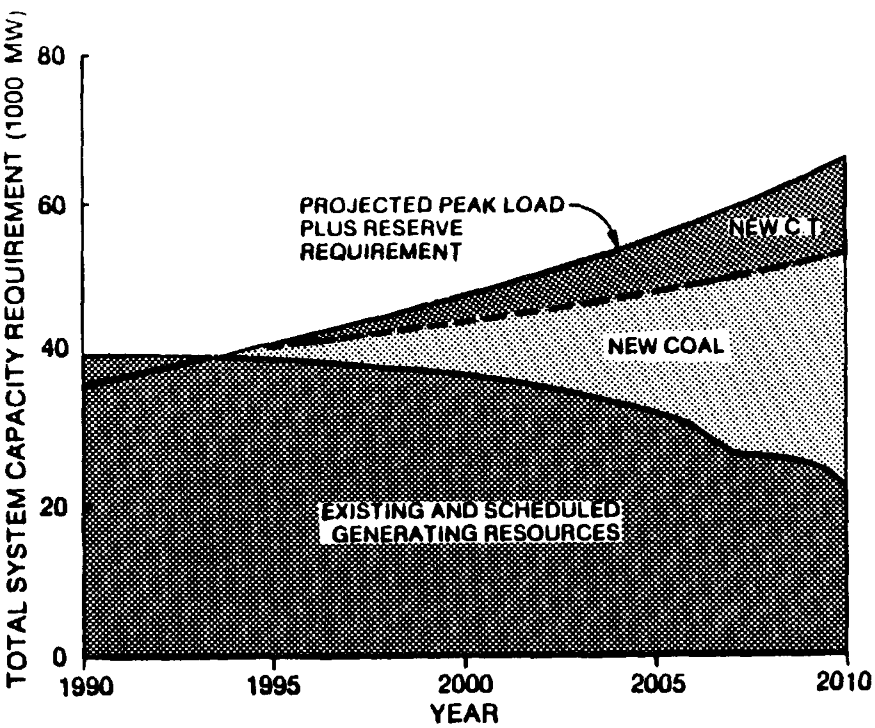

Figure 7-11. Mix of new resources to offset capacity deficits shown on Figure 7-10

suggested that the system energy cost analysis be extended 20 years beyond the end of the last date of the load-resource analysis. For these 20 additional years, only the present value of the system energy costs need to be included, and the costs for these years could be approximated by using those for the last year in the load-resource analysis (Figure 7-13).

c. Develop Plant and System Operating Characteristics. In the preceding section, loads, load shapes, and generating resources were projected through the period of analysis (project on-line date plus 10 to 20 years). Additional information is needed for the production cost analysis of system energy costs: data such as thermal plant heat

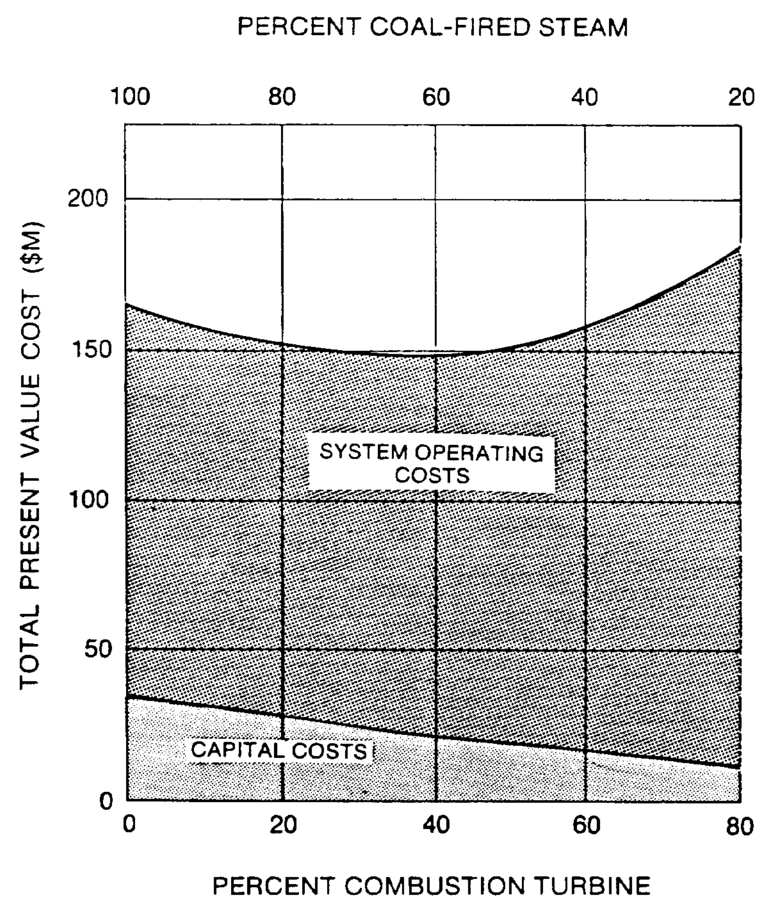

Figure 7-12. Present value cost versus new generating resource mix for hypothetical case described in paragraph 7-5b(7)

rates, maintenance schedules, forced outage rates, variable operation and maintenance costs, fuel types, plant operating modes, existing hydro system energy output, hydro minimum generation, hydro peaking capabilities, and fuel costs. For specific information on what is required, reference should be made to the user manual for the specific production cost model being used. Some of this data can be obtained from FERC, EIA, the regional Power Marketing Administration, or other standard references (15). Other data may be available only from the utilities or the NERC Regional Reliability Council. Fuel costs should reflect expected real fuel cost escalation (see Section 9-5f).

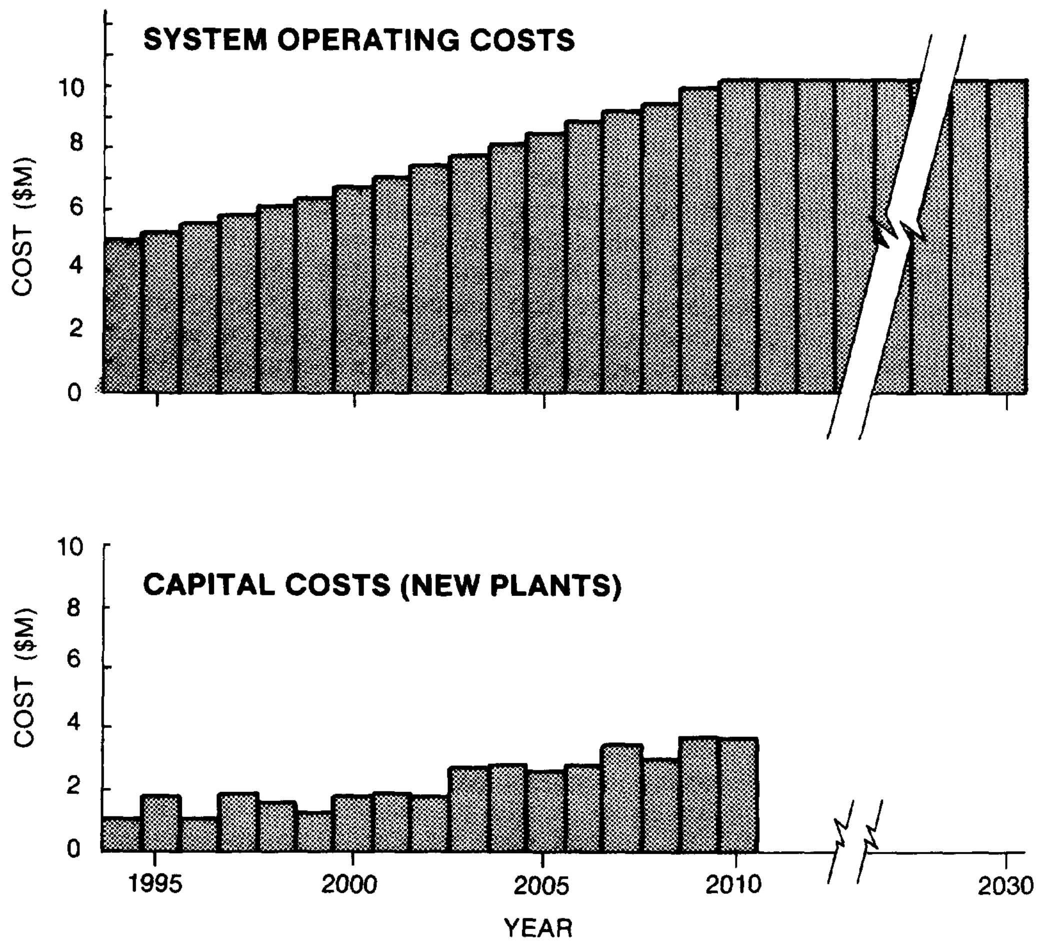

Figure 7-13. Example of cash flow for evaluating a possible new resource mix

d. Compute System Energy Costs. System energy costs would then be computed for each year in the period of analysis using an hourly production cost model such as POWRSYM (see Section 6-9f). The system energy (or production) costs include all of the variable costs associated with operating the power system (principally fuel costs, imported energy costs, and variable operation and maintenance costs). It is not usually necessary to run the model for each year in the period. Production costs could be computed for representative years (at five-year intervals, for example) and costs for intermediate years estimated by interpolation (see Figure 9-2).

e. Define With-Project Conditions.

(1) In most cases, the earliest possible on-line date for a pumped-storage project would be the first year in which a need for additional capacity exists (see Section 7-5b(6)). In some cases, however, the system resource mix may be such that the project could be economically justified earlier. In other cases, the optimum on-line date may be several years beyond the date when capacity deficits first occur. Thus, it is desirable to test several possible on-line dates. For on-line dates occuring after project deficits begin, the without-project scenario is modified by deleting a portion of the new generating resources that were scheduled in Section 7-5b(6). The block of new resources deleted would be equal to the capacity of the proposed pumped-storage project. If the pumped-storage project is large, its units might be scheduled to come on-line over a period of two or three years, and thus it would displace some capacity in each of these years.

(2) The type of capacity replaced could be determined in several ways. If a generation expansion model is available, the pumped-storage project could be entered as an existing resource as of the on-line date, and a new set of resources would be selected to fill in the remaining deficits. The new resource requirements in both the without-project and the with-project scenarios would then be compared, in order to identify the capacity replaced by the pumped-storage project. If such a model is not available, the new resource schedule identified in Section 7-5b(6) would have to be adjusted manually. When adding pumped-storage capacity, the least costly adjustment would usually be to replace combustion turbine capacity, although in some systems, replacing cycling steam or a mix of combustion turbine and steam might be considered. As in the case of the without-project scenario, the advice of the regional PMA, FERC, and local utilities should be sought to assist in developing the most likely with-project scenario.

f. Describe Pumped-Storage Project Characteristics.

(1) In a production cost model (PCM) such as POWRSYM, the pumped-storage project would be described by specifying the following characteristics:

- unit size (rated generating output) in megawatts
- average unit pumping load in megawatts
- number of units
- average generating efficiency (including penstock losses)
- average pumping efficiency (including penstock losses)
- usable reservoir storage, gWh (see Section 7-3c(5))
- start-of-week reservoir storage, gWh
- local reservoir inflow, gWh/hour
- forced-outage rate (see Section 7-21)
- maintenance outage rate or weeks out per year (see Section 7-21)

(2) An hourly PCM typically operates on a one-week cycle, beginning at midnight Sunday. A portion of the weekend pumping required to restore a weekly cycle plant's reservoir storage is typically done in the early hours of Monday morning (see Figures 7-3 and 7-14). Therefore, it is necessary to specify the start-of-week reservoir condition as somewhat less than full. The optimum starting storage is a function of the characteristics of the system being studied and can be determined only by trial-and-error. A start-of-week storage of 85 percent of total usable storage is usually a reasonable assumption for initial runs.

(3) Because pumping load can vary widely with head (Figure 7-7), an average pumping load should be assumed. For initial studies, which must be made prior to pump-turbine selection, it is usually satisfactory to assume an average pumping load equal to or slightly larger than the unit's rated generating output.

(4) Local reservoir inflow to the upper reservoir would represent the net result of local inflow (if any), evaporation, and reservoir precipitation. This is usually specified as an average annual inflow, although it can be specified by week if it is large and varies significantly within the year. In some cases, it may be so small that it can be ignored. At other projects, diversions may be made from the upper reservoir for irrigation or water supply. These diversions would be accounted for as negative inflows. The inflows would be expressed in terms of the gross energy potential of the inflow per hour:

$$\text{Reservoir inflow (gWh/hour)} = \frac{Q_i H_a}{3280} \qquad \text{(Eq. 7-7)}$$

where: Q_i = average weekly inflow, cfs
H_a = average gross head, feet

(5) Many PCM's can treat pumped-storage maintenance outages either by specifying that the units will be out of service for specific weeks, or by utilizing an average availability factor, which the model uses to derate the units week-by-week. If it is desired to examine weekly pumped-storage project operation in detail, it is recommended that the pumped-storage units be scheduled out of service for specific weeks if possible (although it is usually best to account for thermal plant maintenance using the derating method).

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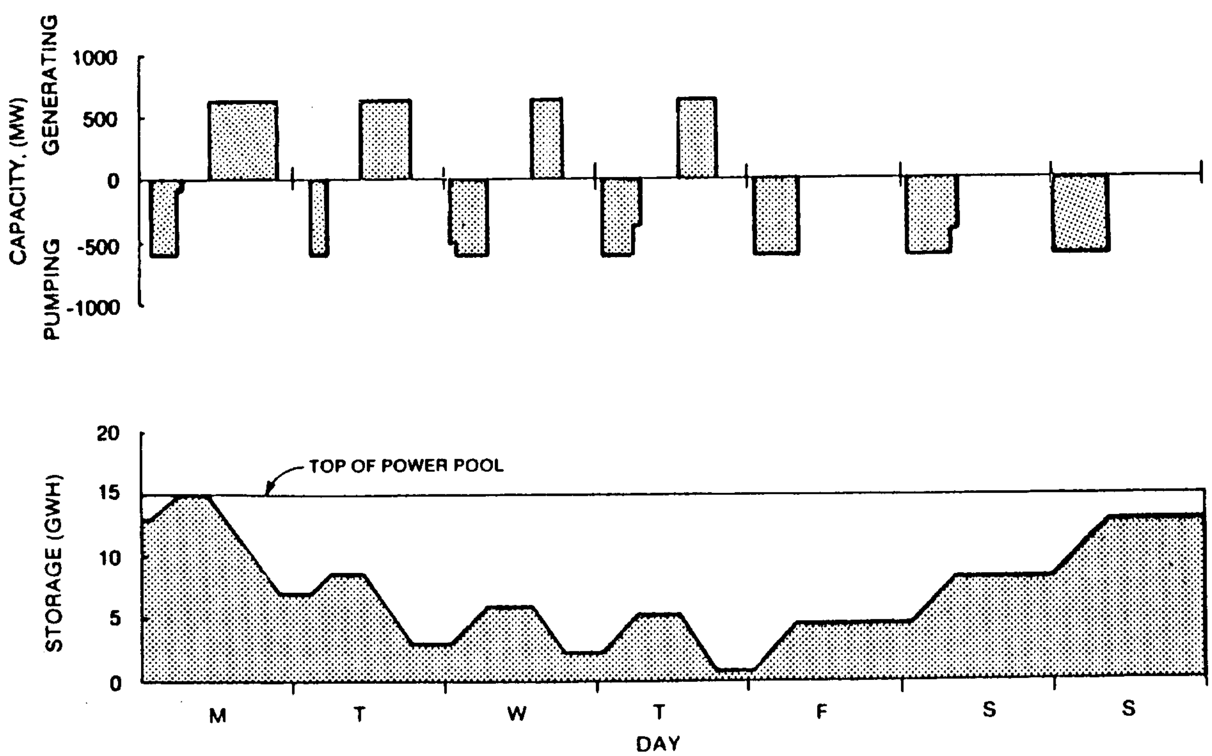

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Figure 7-14. Typical weekly operation for an off-stream pumped-storage project from a production cost model

g. Determine With-Project System Energy Costs.

(1) System energy costs would then be determined for each year in the period of analysis using the production cost model, in the same manner as was done for the without-project scenario (see Section 7-5d). A report of the system and pumped-storage plant performance (costs and generation) can be developed for each week and for each year.

(2) Hour-by-hour reports of pumped-storage plant operation can also be developed. Figure 7-14 shows an example of a weekly loading for a 634 MW off-stream pumped-storage project operating under economic dispatch. Reports of this type (and the resulting storage requirements) can be compared to the design operating cycle, and adjustments can be made to the design operating cycle or storage requirements if necessary. The hour-by-hour pumping and generating values from selected weeks can be used as input to an hourly SSR model, in order to make a detailed routing analysis for a range of expected operating conditions (see Section 7-3c(3)). Statistical data can also be developed to show average storage requirements, in order to evaluate the impact of reservoir fluctuations.

(3) In most production cost models, the pumped-storage plant would normally be operated only if the value of the on-peak energy exceeds the cost of the pumping energy (the economic dispatch mode, as described in Section 7-2c). Economic dispatch often requires considerable computer time, so, in order to save time, a certain amount of must-run pumped-storage operation can sometimes be specified. This value (which might be expressed in terms of gWh of generation per week) should be somewhat less than the generation that would be expected from economic dispatch, and it would be determined through experience in modeling the system under full economic dispatch. The must-run feature can also be used to test project operation under worst-case conditions or to model the operation of the project to meet specific operating conditions (such as operating the project to meet the week-by-week generation values specified by a proposed contract). The system costs developed using the latter type of operation should be used with caution, however, because the system may be forced to operate in a non-economic manner, and the resulting system energy benefit would not likely represent NED benefits.

h. Determine System Energy Benefits.

(1) The difference in total system operation costs between the without-project system (Section 7-5d), and the with-pumped-storage-project system is the net savings in system costs. This savings represents the difference between the value of the energy displaced and the cost of the pumping energy, and it accounts for any other

TABLE 7-4
Computation of System Energy Benefits for a Given Year
(all values in $1,000)

System energy costs without pumped storage	$5,917,720
System energy costs with pumped storage	$5,907,030
Net system energy cost savings	$10,690
Net system energy cost savings	$10,690
Pumping energy costs	$54,940
System energy benefits	$65,630

changes in system operating costs that result from replacing a specific increment of thermal generation with the pumped-storage capacity.

(2) In an NED benefit-cost analysis, the pumping energy cost should be included as a cost rather than as a negative benefit (Section 8-5e), so it must be removed from the net difference in system costs. The pumping energy cost can be computed as a part of the PCM analysis and included in the output reports. The sum of the net system energy cost and the pumping energy cost would be the system energy benefit attributable to the pumped-storage operation. Table 7-4 illustrates such a computation for a given year's operation.

(3) Similar calculations would be made for each year in the period of analysis. As noted earlier, PCM runs do not have to be made for each year in the period. Runs can be made for representative years and values for intermediate years determined by interpolation. Energy benefit values would have to be computed for each year of the project life, which would typically be 50 years in the case of an off-stream pumped-storage project (see Section 9-3c). Because of uncertainty and because of the limited effects of benefits for distant years on average annual benefits, production cost analysis would usually be limited to no more than the first 20 years following POL (see Section 7-3d). Energy benefits and pumping costs for subsequent years (year 21 through year 50, for example) can be represented by the values for the last year of the PCM analysis (year 20 in the example case). Given the values for all 50 years, average annual energy benefits and pumping costs can be computed by present-worthing all of

the annual values to the project on-line date and amortizing over the life of the pumped-storage project.

i. Determine Capacity Benefits. The type (or mix) of thermal capacity that would likely be displaced by the pumped-storage project was determined as described in Section 7-5e. Capacity benefits would be computed using the capital costs for these plants (see Sections 9-3b, 9-5a through 9-5c, and 9-8c(5)), and the pumped-storage project's dependable capacity (see Section 6-7j).

j. Flexibility Benefits.

(1) It is widely recognized that pumped storage has flexibility (or "dynamic") benefits that are not well quantified using present evaluation techniques, and the Electric Power Research Institute (EPRI) has research underway in this area (68). An adjustment is usually made to the capacity values in an attempt to account for the inherent flexibility of hydropower compared to thermal capacity (see Sections 9-5c and O-2e). However, the EPRI studies suggest that this adjustment (a five percent increase in the capacity value) underestimates the flexibility benefits for pumped storage. Prior to assigning flexibility credit to a specific pumped-storage project, the latest EPRI studies should be reviewed in order to determine if a better basis exists for assigning a value to flexibility. If not, the 5 percent flexibility credit described in Section O-2c can be used on an interim basis.

(2) Production cost models such as POWRSYM normally treat thermal plant outages probabilistically, by computing the costs of reserve capacity operation after the pumped-storage dispatch has been completed. Hence, the use of pumped-storage generation to help cover for thermal plant outages is not accounted for in the system cost analysis. An option is available in POWRYSM (and perhaps other PCM's) which treats forced outages on a Monte Carlo basis, and the use of this technique would give pumped-storage credit for this operation. The Monte Carlo technique requires considerably more computer time, but a sensitivity analysis could be made to give an estimate of the benefit gains to be realized, so that adjustments can be made to other PCM runs.

k. Sensitivity Analyses. Paragraphs 7-3d(7) and (8) list some of the variables that need to be considered in evaluating and scoping a pumped-storage project. It can be seen from the foregoing discussion that a proper economic analysis of an off-stream pumped-storage project is a relatively detailed and rigorous procedure. This is to be expected, because projects of this type are typically large, requiring sizable investments. However, treating all possible development alternatives and planning assumptions in detail would require excessive planning resources (time, manpower, and money). The analysis should be designed in such a way as to keep study costs as low as possible, while still producing an adequate level of accuracy and detail. One way to conserve both time and computer costs is to do a rigorous analysis of a few of the most likely alternative development plans and treat as many of the variables as possible in sensitivity studies, rather than doing a complete analysis of all of the possible alternative planning assumptions and development alternatives. Figure 7-15 shows, as an example, a sensitivity analysis that is intended to obtain a preliminary indication of the relative benefits of additional reservoir storage. A similar test could be applied in the final stages of project scoping to verify that the initial decision regarding reservoir storage was correct.

7-6. Analysis of Pump-Back Projects.

a. General. The operation of an on-stream or pump-back type pumped-storage project consists of a pumped-storage operation superimposed on a conventional hydro peaking operation, and the analysis of such a project requires a combination of the techniques used to evaluate both types of projects. This section describes how these various techniques would be used to perform such an analysis.

b. Objectives of Pump-Back Operation.

(1) Reversible units may be installed in conventional on-stream hydro projects either to increase the dependable capacity of a conventional power installation or to permit a larger power installation (or a combination of both). An example of the former would be a pondage project where streamflow is adequate to firm up the installed capacity most of the time, and pump-back would be used to help support the capacity only during occasional low flow periods. The reversible units at the Harry S. Truman project were installed to serve this purpose.

(2) The latter approach would be used to permit a large peaking installation at a site that has low streamflow, but is otherwise well-suited for a peaking development. Figures 6-19 and 6-20 in Section 6-8d graphically illustrate how pump-back can be used to increase plant capacity. The four pump-turbine units installed to expand the power installation at the Richard B. Russell project are an example of this type of philosophy. The initial (conventional) units at Russell fully developed the natural streamflow, so the additional units were designed to be supported most of the time with off-peak pumping energy. The location of the Russell project between two storage projects, which provide the necessary regulation and reregulation, made this type of installation attractive. At other projects,

reversible units may be installed to accomplish both purposes. Pump-back can be installed at pondage projects, projects with seasonal power storage, and multiple-purpose storage projects.

(3) Prior to considering pump-back, the power system must be examined in order to determine if low-cost off-peak pumping energy is available and if the on-peak generation that would be displaced is high-cost energy. If not, pump-back will not be feasible. This preliminary examination would be made in coordination with the regional PMA, FERC, or the local power utilities. This step is very important, and must be done carefully. There is no reason to expend effort on detailed studies of pump-back if it cannot operate economically in the power system.

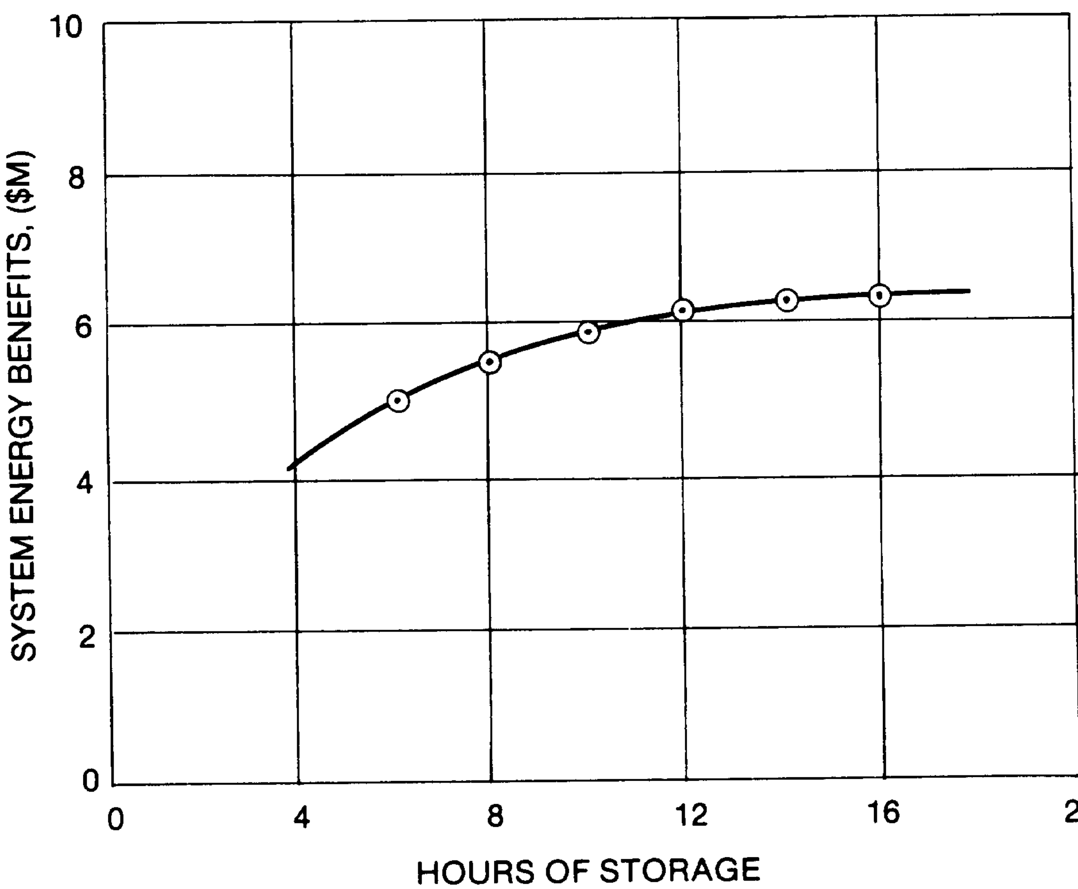

Figure 7-15. Sensitivity analysis showing the effect of reservoir size on system energy benefits

(4) Another requirement for pump-back is a downstream reservoir to serve as the lower reservoir for the pump-back operation and to regulate peaking discharges from the pump-back project to meet downstream flow requirements. This could be an existing reservoir or a specially constructed reregulating reservoir. Section 6-8c provides further information on reregulating reservoirs.

c. Basic Procedure.

(1) The analysis of a pump-back project requires that both period-of-record and hourly sequential streamflow analyses be made. A period-of-record routing must be made without pump-back in order to determine the conventional hydro energy potential of the project. Hourly studies are then made for selected weeks (or other suitable intervals) to determine the capacity that can be supported with a conventional pondage operation, and to identify the additional capacity that can be supported by adding pump-back. Additional period-of-record seqential routing studies are usually run with the pump-back installation in order to determine how often pump-back operation will be required.

(2) Following are the basic steps that would be followed in the analysis of a pump-back project:

- make a period-of-record routing to define the project's energy potential without pump-back.
- establish the on-peak generating pattern required for dependable capacity.
- select a range of possible plant sizes (the remaining steps are performed for each plant size).
- perform a series of hourly or multi-hourly routings in order to determine the dependable capacity without pump-back.
- identify the "worst case" week to serve as the basis for designing the pump-back installation.
- determine the hours when off-peak pumping energy is available.
- perform a preliminary routing for the worst-case week in order to to determine the pondage and reregulating reservoir requirements.

- select the appropriate mix of conventional and reversible units (or select several possible mixes).

- perform a series of hourly or multi-hourly routings to determine the dependable capacity and the maximum pumping requirements with pump-back.

- perform a system production cost analysis to determine whether pump-back is economical and to determine the average amount of pump-back operation that is required.

(3) At some pump-back projects, conventional hydro generation represents only a small portion of the energy output. In such cases, it is more appropriate to analyze the project as an off-stream pumped-storage project (as described in Sections 7-3 through 7-5), with conventional generation accounted for by specifying inflows to the upper reservoir (see Section 7-5f(4)).

d. Base Period-of-Record SSR Analysis.

(1) A base period-of-record sequential streamflow (SSR) routing is required in order to determine the project's energy output for each interval without pump-back. For storage projects, this routing would also serve to define the reservoir's seasonal operating pattern. The routing would be made generally as described in Chapter 5, following the procedures corresponding to the specific type of project being analyzed (i.e., pondage project, power storage project, multiple-purpose storage project, project operating as part of a system, etc.).

(2) In the case of projects with power storage, some modifications to the operating procedures can sometimes be made in order to take advantage of the pump-back capability. For example, it might be preferable to maintain a reservoir at an elevation such that rated capacity can be delivered at all times, rather than drafting the reservoir below that elevation to meet firm energy requirements (see Section 5-13c).

(3) When pump-back is being considered for addition to an existing project or for incorporation in a project already in the planning stage, it may be possible to utilize an existing routing as the base case analysis.

e. Define Project's Dependable Capacity Without Pump-back.

(1) The first step is to define the operating criteria that would make a project's peaking capacity dependable. Some systems require only that dependable capacity be supported either by (a) a specific minimum energy during the peak demand period, or (b) specific

minimum amounts of energy during each week or month of the year (see Section 6-7e). In other systems, the capacity must meet specific sustained capacity criteria, which reflect the number of hours on peak, minimum flows, and other factors (see Section 6-7i). The dependable capacity criteria are usually be established in coordination with the regional Power Marketing Administration.

(2) Whichever method is used, the dependable capacity criteria can be converted to a series of minimum energy requirements per week or month. These values would usually be expressed in terms of kilowatt-hours of energy required per kilowatt of firm peaking capacity. Separate values can be assigned for each week (or month) of the year, or just for each week (or month) during the peak demand period, depending on the criteria being followed.

(3) These values are then applied to the project's energy output from the period-of-record routing, in order to determine the amount of capacity that can be supported in each time interval without pump-back. If the average availability method is being used to measure dependable capacity (see Section 6-7g), one or more plant sizes can be assumed and the average capacity available during the peak demand months (over the period-of-record) can be computed for each. If the "firm plant factor" method is used (see Section 6-7e), the dependable capacity would be defined by the water year with the least amount of energy production during the peak demand months.

f. Define the Operating Cycle for Pump-Back Operation. The operating cycle for pump-back operation must be defined next. This is required in order to make the "worst-case" SSR routings which will establish the pondage and reregulating reservoir requirements for different plant sizes (or, if the available storage is fixed, which will determine the maximum installed capacity that should be considered). The operating cycle is defined in basically the same manner as for off-stream pumped-storage projects, in that the required number of hours of on-peak generation per weekday and the number of hours of off-peak pumping energy available per weeknight must be identified (see Section 7-2c). These values are normally established just for the peak demand months, but in some cases it may be necessary to define values for other periods as well.

g. Make Worst-Case Hourly SSR Routings.

(1) The "worst-case" week, which will serve as the basis for pump-back project design, will be the condition that puts the greatest stress on the project. It may be the historical peak demand week with the lowest average discharge, or it may be a week with an average flow having a recurrence interval that is consistent with the regional power system reliability criteria (once in ten years, for example).

(2) A range of potential plant sizes would then be selected as described in Section 6-2.

(3) Using the required on-peak generating pattern, the hours that off-peak pumping energy is available, and the downstream discharge requirements, an hourly routing must be performed for the "worst-case" week in order to determine the pondage and reregulating reservoir requirements for each plant size. As suggested in Section 6-8c(2), it may be desirable to base this analysis on a three-day weekend. If physical constraints limit the amount of pondage or reregulating reservoir capacity available, it may be possible at this stage to eliminate some of the proposed plant sizes.

(4) The routing study for the worst case week will also help identify the minimum amount of capacity that must be reversible. The most economical installation will usually be the mix with the minimum number of reversible units, but where the maximum pumping capacity and maximum flexibility is required, the choice may be all reversible units. It may be necessary to test several mixes in order to identify the combination that produces the maximum net benefits.

(5) This analysis would be done using an SSR model with hourly routing and pumped-storage evaluation capability, such as HEC-5 (see Sections 6-9 and K-5).

h. Compute Pump-Back Requirements for Period-of-Record.

(1) A period-of-record sequential routing must then be made for each plant size in order to determine how much pump-back will be required to meet dependable capacity criteria. A variety of different approaches can be taken to making this analysis, depending on the complexity of the system and the SSR model available.

(2) One approach is to use a daily routing interval. The first step in such an analysis would be to specify a minimum daily generation requirement, which would be based on the number of hours of on-peak generation required per day (this could vary by day of the week and by month, or by season). It will also be necessary to specify the maximum amount of energy that could be pumped with available pumping energy each weeknight and on weekends. Using a pondage project that is required to produce peaking power five days a week as an example, the generation from inflow is first computed for each weekday and compared with the minimum daily generation requirement. If the requirement is greater than generation from inflow, some pondage must be drafted. Pumping energy is then applied in an attempt to restore the reservoir that night. If the reservoir cannot be restored during the week-nights, it will gradually be drawn down until the weekend, when additional pumping energy becomes available. For a multiple-

purpose project, this operation would also have to accomodate releases to serve other project purposes.

(3) With this analysis, it is possible to determine the amount of pumping energy required to insure that the required on-peak power can be delivered throughout the period-of-record. However, the average annual generation and average annual pumping energy values obtained from these studies would not generally be used in the economic analysis, because they represent the maximum expected pump-back operation rather than the average pump-back operation. The economic analysis must account for the day-to-day (and hour-to-hour) variations in the value of on-peak power and off-peak pumping energy. A production cost analysis is normally used to define the average pump-back operation.

(4) For some projects, the use of pump-back will make the installed capacity fully dependable. At other projects, however, head loss due to reservoir drawdown or tailwater encroachment will result in reduced capacity during some periods. In such cases, the period-of-record daily routings can be used to estimate the average capacity available during the peak demand period (see Section 6-7g). The period-of-record routings can also be used to test alternative mixes of conventional and reversible units.

i. Economic Analysis.

(1) General. The procedure for evaluating the benefits for a pump-back project is generally similar to that for an off-stream pumped-storage project (see Section 7-5). Because pump-back projects are usually smaller and because they depend on pumping for only a part of their generation, the analysis can often be simplified. For example, if a project is relatively small compared to system loads and most of the generation is from natural inflow, it may be necessary to examine only one or two typical load years rather than a sequence ten to twenty years beyond the on-line date. However, for large plants, especially those where generation is mostly from pump-back, a more rigorous analysis would be required. If the detailed analysis is required, the procedure described in Section 7-5 should be followed, except that a production cost model capable of handling a pump-back project must be used (see paragraphs 7-6i(4) and (6)). The remainder of this section deals with the analysis of a smaller project.

(2) Define Base Conditions. The system for analysis should include the utilities where the power will be marketed and adjacent utilities whose system operation might be influenced by the pump-back project operation. For many pump-back projects, this will be a single power supply area. A load-resource analysis must be made to determine when new capacity would first be needed. If the pump-back

project is small and the system resource mix is not expected to change significantly with time, it may be sufficient to examine only a single representative year, typically within the first ten years after the project on-line date (POL). In other cases, it is best to analyze two different load years (five and ten years after POL, for example), and if studies show a major change in energy benefits between the two years, additional years should be examined and energy benefits should be determined for intervening years by interpolation (as in Figure 9-2).

(3) Define Without-Project Scenario. With the information on projected deficits obtained from the load-resource analysis, additional resources are be scheduled such that sufficient capacity will be available to meet projected peak loads with an adequate reserve margin in the load year (or load years) being examined. The new resource mix can be determined using optimized generation expansion techniques, as described in Section 7-5b(6) through (9)), or it can be projected based on discussions with the regional PMA and local utility planners. Plant data and hourly load shapes would be developed as described in Section 7-5c.

(4) Compute Without-Project System Energy Costs. System energy costs for the without-project case would be developed using an hourly production cost model as described in Section 7-5d. The POWRSYM model has been modified by North Pacific Division to handle pump-back projects, and it is recommended that this model be used for such analysis.

(5) Define With-Project Scenario. In this scenario, the pump-back project will replace an increment of the new capacity scheduled in step (3), above. The type of capacity replaced will be the most likely alternative, and since a pump-back project is usually a peaking project, the most likely alternative will normally be combustion turbine, cycling steam, or a mix of the two. It may be necessary to make several with-and-without project analyses in order to determine which alternative or mix of alternatives is most appropriate.

(6) Describe the Pump-Back Project. In POWRSYM, the pump-back project is modeled as a "pump-storage project". The same basic input data is required for a pump-back project as is required for an off-stream pumped-storage project (see Section 7-5f). In adapting POWRSYM to handle pump-back operation, the model was modified such that the following parameters can be specified by week:

- number of units available
- unit generating capacity, MW
- average unit pumping capacity, MW
- start-of-week reservoir elevation, gWh

- end-of-week reservoir elevation, gWh
- local reservoir inflow, gWh/hour

Reservoir inflow is modeled as "local inflow to the upper reservoir." Weekly average inflows are obtained from the period-of-record SSR routing and converted to potential energy, in gWh/hour (see Section 7-5f(5)). The number of units and the unit pumping capacity can be specified by week so that operating restrictions, such as limited or no pump-back during certain seasons, can be modeled. The model does not presently accomodate a mix of conventional and reversible units, but this type of installation could be approximated by assuming that all of the units are reversible and assigning a reduced equivalent pumping capacity to each of the units. This equivalent capacity value would be computed by dividing the total (average) pumping capacity of all reversible units by the total number of units, reversible and conventional. In this way, the total pumping capacity will never be exceeded, even though all units are in effect being modeled as reversible units. By specifying start-of-week and end-of-week reservoir elevations, it is possible to simulate the regulation of seasonal storage projects. Such values can be obtained from period-of-record SSR studies and converted to potential energy in gWh (see Section 7-3c(5)). In many cases, average annual energy benefits can be approximated by modeling only an average water year (i.e., specifying inflows and, in the case of storage projects, reservoir elevations for an average year from the period-of-record SSR analysis). However, when it is anticipated that the variations of inflows and reservoir elevations from year to year will have a significant effect on energy benefits, it may be necessary to model a range of representative water years. System energy benefits would then be based on a weighted average of those runs. If this is done, energy data for any existing conventional hydro in the system must also be adjusted to reflect the varying water conditions.

(7) Determine With-Project System Energy Costs. System energy costs are then computed with the production cost model for the system with the pump-back project. The model will produce output information similar to that for an off-stream pumped-storage project (see Section 7-5g). Figure 7-16 shows an example of a typical week's operation for a pondage project with pump-back. POWRSYM dispatches the project's generation from natural streamflows first, with pump-back normally being used only if it is economical (see Section 7-2c(2)).

(8) Determine System Energy Benefits. Average annual system energy benefits and average annual pumping costs for a pump-back project are computed in the same way as for an off-stream pumped-storage project (see Section 7-5h), except that in some cases they will be based on only one or two representative years.

(9) Determine Capacity Benefits. Capacity benefits are computed by applying unit capacity values (based on the capital costs of the thermal alternative replaced by the pump-back project) to the pump-back project's dependable capacity (see Sections 9-3b, and 9-5a thru 9-5c). Note that for some projects, the dependable capacity may be less than the installed capacity (see Section 7-6h(4)).

j. Additional Hours SSR Studies. It is often desirable to make additional hourly SSR studies, in order to examine pondage and drereguIation reservoir requirements and water surface fluctuation rates under other than worst-case conditions. Weekly generation and pumping schedules for making these analyses can be obtained from production cost model runs.

k. Unit Characteristics.

(1) As noted earlier, power installations at pump-back projects can be all reversiblae units or a mix of reversible and conventional

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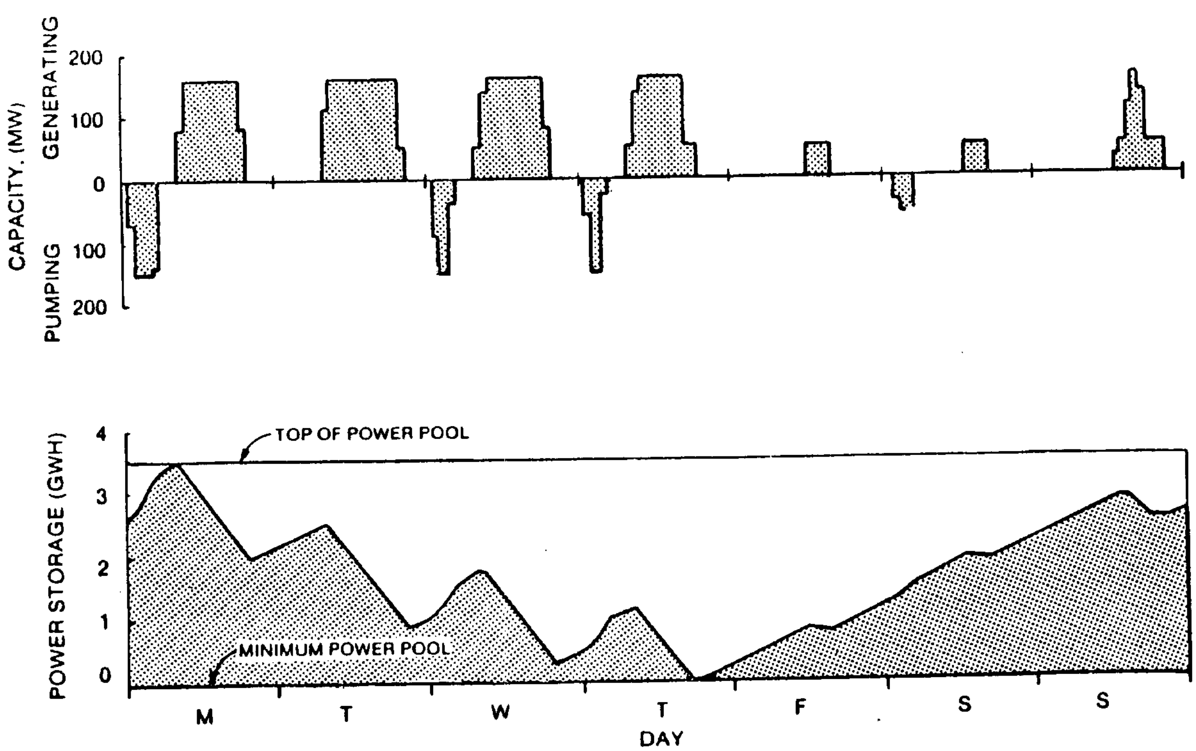

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Figure 7-16. Operation of a pump-back project for a typical week based on a production cost analysis.

units. The characteristics of conventional units are described in Section 5-5. The characteristics of reversible units for pump-back operations are generally as described in Section 7-2.

(2) Heads are usually smaller for pump-back projects than for off-stream pumped-storage plants. Hence, the head range for efficient operation becomes more of a consideration, particularly at multiple-purpose storage projects, where large reservoir fluctuations are required to serve other project functions. In some cases, it is necessary to limit the head range in which pumping can be accomplished. Where a mix of conventional and reversible units are installed, the two types of units can be designed for somewhat different operating head ranges to permit efficient operation over the full project head range. Submergence requirements can also be an important consideration, particularly at above-ground powerhouses.

l. Alternative Project Configurations and Sensitivity Studies. Some of the variables that might be considered at pump-back projects include alternative plant sizes, alternative unit sizes, alternative mixes of conventional and reversible units, alternative reservoir sizes, and alternative reregulating reservoir configurations. Sensitivity studies can also be made to test alternative on-line dates, alternative fuel cost escalation rates, alternative load growth rates, and alternative load shapes.

7-7. Special Problems.

a. General. This section briefly reviews some of the special types of pumped-storage projects and other special problems involved in the analysis of pumped-storage.

b. Screening Studies.

(1) The first step when considering the addition of off-stream pumped-storage to a system is often a comparative examination of alternative sites in the area. Such a study is usually conducted in stages. The first step is to identify all potential sites. Then, physical screening criteria can be applied to eliminate the most costly sites. Such criteria could include minimum head, maximum penstock and tunnel length, distance from load centers, and the minimum plant size that can be supported. Another screening can be done to eliminate those projects in environmental or politically sensitive areas. Those projects that survive these tests would then be costed out, with the best site or sites then being considered for a reconnaissance level analysis.

(2) A number of pumped-storage inventories and screening studies have been completed, and three of them are described in references (85) through (88). The Bureau of Reclamation has developed a screening procedure for comparative evaluation of water resource projects (63) which may be of some value to Corps of Engineers planners in evaluating pumped-storage projects.

c. Seasonal Pumped-Storage.

(1) Off-stream seasonal storage for power and other functions is sometimes attractive because it represents a possible means of obtaining storage without obstructing existing waterways. Section 7-1b(4) describes two existing U.S. seasonal pumped-storage projects. However, development of seasonal pumped-storage has not been extensive in the U.S. to date, because the high costs of embankment structures and pumping energy, together with the impacts of flooding large reservoir areas, have usually more than offset the benefits to be gained. However, there may yet be cases where the value of stored water, whether for power or for other purposes, will be great enough to warrant consideration of such developments.

(2) Such a project would inherently be a multiple-purpose project. For example, assume that an off-stream storage reservoir is needed for low flow augmentation. Water would be pumped into storage in the high runoff season, providing flood control benefits in some years and possibly using secondary energy which would otherwise be spilled for pumping. Where the water is released for low flow augmentation, relatively high value of energy may be produced. The upper reservoir could also provide reduced pumping head for irrigation of adjacent areas, and a daily/weekly cycle pumped-storage project operation could be superimposed on the seasonal operations.

(3) Analysis of the seasonal operation would be made using standard seasonal SSR techniques (Chapter 5), utilizing a SSR model with pumped-storage capabilities. The daily/weekly cycle pumped-storage operation would be evaluated as described in Section 7-2 through 7-5.

d. Underground Pumped-Storage.

(1) Underground pumped-storage is a variation of the daily/weekly cycle type of development in which the lower reservoir is underground. This type of development has the advantage of considerable flexibility in siting. Underground pumped-storage projects can be chosen which have relatively minor environmental and political impact, whereas sites which are suitable for above-ground

development almost inherently have significant impacts. Furthermore, both the upper and lower reservoirs can be considered off-stream reservoirs, so there will be relatively little impact on existing waterways.

(2) From the planning standpoint, underground projects are analyzed in basically the same manner as above-ground daily/weekly cycle off-stream pumped-storage projects. There are, however, additional design complexities, particularly in the areas of geology, construction, and machinery design. Both the U.S. Department of Energy and the Electric Power Research Institute have supported research on underground pumped-storage in recent years. Reference (90) and Section 3 of Volume III of Reference (12) should be consulted for further information in this area.

e. Multiple-Purpose Operation. At daily/weekly off-stream pumped-storage projects, the opportunities for multiple-purpose operations are limited, but some examples of incorporation of other functions do exist. A pumped-storage project could be used to pump water for local irrigation or water supply systems. Recreational facilities could be constructed on lower reservoirs if reservoir fluctuations are not too large. On the other hand, it is sometimes possible to add daily/weekly cycle pumped-storage operations to a facility that is designed primarily to convey or store water for other purposes. Examples are (a) the Castaic project, which is located on the West Branch of the California Aqueduct, (b) the Mt. Elbert project, which is located on one of the conduits of the Fryingpan-Arkansas inter-basin diversion project, and (c) the Grand Coulee pumping plant, which pumps water from the Grand Coulee Reservoir to Banks Lake, a key storage reservoir for the Columbia Basin Irrigation project. The multiple-purpose aspects of seasonal pumped-storage were discussed in Section 7-7c. Pump-back can also be readily incorporated in a project that serves multiple purposes.

f. Environmental Problems. While a detailed discussion of the environmental problems associated with pumped-storage is beyond the scope of this manual, two problems that are commonly encountered at pumped-storage projects are worthy of special mention: (a) intakes at lower reservoirs often must be screened to prevent fish from being drawn into the powerplant during the pumping operations, and (b) large daily/weekly reservoir fluctuations are often required, particularly at upper reservoirs. Additional information on environmental impacts of pumped-storage can be found in references (22), (48j), and (88).

TABLE 7-5
Maximum Pumped-Storage Development by Region
As Reported in the National Hydropower Study 1/

Northeast (NPCC & MAAC)	3,400 MW
Southeast (SERC)	18,600 MW
North Central (ECAR, MAIN & MAPP)	36,000 MW
South Central (SPP & ERCOT)	1,300 MW
West (WSCC)	600 MW
	59,900 MW

1/ base case projections, from Table 5-6 of reference (48j)

g. The National Hydropower Study.

(1) Dames and Moore has prepared An Assessment of Hydroelectric Pumped-Storage for the Corps of Engineers as a part of the National Hydroelectric Power Resources Study (48j). This report contains detailed information on most existing and planned U.S. pumped-storage projects (pump-back as well as off-stream). Included are case studies of several recently proposed projects and the problems associated with bringing these projects through the planning process and into production. The report also includes a discussion of the alternatives to pumped-storage hydro and a comparative assessment of pumped-storage hydro with these alternatives.

(2) An attempt was also made to assess the potential need for pumped-storage by region, using a generalized production cost model. This analysis tested a number of alternative planning assumptions with respect to load growth resource dispatch philosophy, powerplant retirement schedules, and load management. The study, which was generally based on NERC regions (Figure 3-1), showed that the largest potential need for pumped-storage would occur in the north central states (MAPP, MAIN, AND ECAR) and the southeastern states (SERC). Some need was also identified in the northeast (NPCC and MAAC) and in the south central states (SPP and ERCOT). Very little pumped-storage appeared to be required in the Western states (WSCC), largely due to the availability of conventional hydro for peaking service. Table 7-5 lists the maximum pumped-storage development projected using base case planning assumptions.

(3) These projections should be used with caution, because some of the planning assumptions are now dated, the model used for the analysis was of necessity somewhat simplistic, and the study was based on large, multi-region areas. However, they should give a general indication of the most promising areas for development. It is recommended that this analysis be carefully reviewed in the process of making any pumped-storage feasibility study.