Survey and Analysis of Selected Jointly Owned Large- Scale Electric Utility Storage Projects

May 1982

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SURVEY AND ANALYSIS OF SELECTED
JOINTLY OWNED LARGE-SCALE ELECTRIC
UTILITY STORAGE PROJECTS

Battelle Columbus Laboratories

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Pacific Northwest Laboratory
Richland, Washington 99352

EXECUTIVE SUMMARY

The intention of this report was to examine and document the issues surrounding the curtailment in commercialization of large-scale electric storage projects. With the benefits of these large-scale storage systems well documented it was felt that the forces prohibiting widespread commercialization of these systems needed to be investigated. It was further sensed that if these issues could be uncovered, then efforts might be directed toward clearing away these barriers and allowing these technologies to penetrate the market to their maximum potential.

Joint-ownership of these projects was seen as a possible solution to overcoming the major barriers of commercialization. The benefits of joint ownership, namely combined demand for more than one utility to take advantage of large economies of scale and to increase capacity maximization, reduced capital cost needed by each participating member, and increased political strength when trying to gain regulatory approval, was viewed not as a panacea, but an aid to parties with an interest in building large-scale storage in these difficult economic times. Investigation of four prior joint-ownership agreements revealed some interesting perspectives on the problems and benefits of these arrangements.

Discussion with partners involved in four pumped storage projects took place to identify the difficulties and advantages of joint-ownership agreements. The four plants surveyed included Yards Creek (Public Service Electric and Gas and Jersey Central Power and Light); Seneca (Pennsylvania Electric and Cleveland Electric Illuminating Company); Ludington (Consumers Power and Detroit Edison, and Bath County (Virginia Electric Power Company and Allegheny Power System, Inc.). Also investigated were several pumped storage projects which were never completed. These included Blue Ridge (American Electric Power); Cornwall (Consolidated Edison); Davis (Allegheny Power System, Inc.) and Kittatiny Mountain (General Public Utilities). The history, negotiations and issues for each of these projects are covered in Sections 3 and 4 of this report.

The issues uncovered during the investigation of these projects are categorized and presented in Section 5. Since it was difficult to separate the issues relating to joint-ownership from the issues relating to large-scale energy storage in general, all of these are included in this section. Categories include institutional, regulatory, technical, environmental, economic, and special issues.

The conclusions of the report are presented in Section 6.0. The major barriers preventing the growth of energy storage are the high cost of these systems in times of extremely high cost of capital, diminishing load growth in the utility industry which lessens the demand for new generation and storage facilities, and regulatory influences which will not allow the building of large-scale storage systems due to environmental objections or other reasons. These factors have contributed to weaken the market for large-scale storage systems.

There are some advantages to joint ownership in the utility community and the trend (see Figure 10) toward joint-ownership will undoubtedly continue. Combining forces to build a storage project can maximize its capacity utilization taking advantage of large economics of scale. Joint-ownership also reduces capital cost needed by each participating utility while still allowing them the benefits of a storage system.

Not all of the factors of joint-ownership are beneficial. There are a myriad of issues relating to financing, operation, transmission, etc. which need to be negotiated prior to an agreement. After an agreement between the parties is reached (this may take several years), the regulatory agencies with jurisdiction over the project or jurisdiction over the utilities must also approve the agreement. While in most cases the regulatory approval is a formality, there are cases (e.g., Bath County) where this regulatory snarl can delay or even cancel a proposed agreement. This multiple regulatory approval process can be a barrier for both the implementation of joint-ownership agreements and to the building of large-scale storage in general.

The future for energy storage looks viable despite difficult economic times for the utility industry. Joint-ownership can ease some of the economic hardships for utilities which demonstrate a need for energy storage. The negotiation of this type of agreement is sometimes long and difficult but the benefits to each participant can be large. The future for above ground pumped storage looks bleak due to environmental concerns and public opinion but this technology will be replaced with compressed air storage and underground pumped hydro storage. The technical feasibility of these systems will be demonstrated in the next few years and compressed air storage has a major regulatory advantage over pumped storage. No Federal Energy Regulatory Commission approval will be needed for this option.

Finally, regulatory reforms to assist the utility industry will probably be implemented. With the promise of reducing the regulatory burden in this country, the Reagan Administration has put together a task force to look into problems plaguing the utility industry. Some of the issues they will attempt to resolve are: (1) an equitable rate of return for recommendation to State Utility Commissions, (2) should utilities earn a return on capital invested in new facilities under construction, (3) should customers or stockholders pay for an expensive "bad guess" by management on need for a new plant, and (4) the duplication of regulatory oversight which exist at the federal, state, and local levels. It is likely some regulatory reforms will be implemented which will result in more capital investment. The demonstration of second generation technologies, the continuing steady growth in electric power demand, and an improved fiscal climate will result in an improved market for large-scale energy storage.

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A RESEARCH REPORT
on
SURVEY AND ANALYSIS OF SELECTED
JOINTLY OWNED LARGE-SCALE ELECTRIC
UTILITY STORAGE PROJECTS
by

J. Hurwitch, J. Ott,
R. Healy, and M. Hanley

April 1982

1.0 INTRODUCTION

1.1 Problem Statement

This project was undertaken under the sponsorship of the Department of Energy to identify and analyze the attractive, non-technical features supporting shared storage and the major barriers outside the technical realm that inhibit the operation and construction of multi-utility storage projects. Recent estimates of future load profiles have indicated that most individual utilities cannot effectively utilize the large capacity of a storage plant. Rather, cooperative storage projects might offer economic benefits and energy conservation alternatives for cooperating utilities. This research effort was intended to evaluate the overall marketability of storage projects in order to facilitate the commercialization of present and future storage technologies. The major objective of this study was to investigate and report on the perceptions of storage technologies, associated characteristics of joint projects, and significant issues of the utility community itself.

1.2 Research Activities

Perceptions of the electric power utility industry related to joint ownership and use of stored power generation technologies, specifically pumped hydroelectric storage, were gathered through personal interviews. The interviews were conducted in an informal manner with management and technical personnel of representative electric power companies. Rationale for choice of those companies is provided in the body of this report.

Pumped hydro is the focus of this investigative task since it is presently the only storage technology to be successfully commercialized and generally accepted by utilities.

The advantages and disadvantages of joint storage projects were identified according to the following categories:

- Economic (costs, benefits)
- Regulatory (federal, state, local)
- Environmental
- Institutional
- Technical.

It is obvious that these categories are not mutually exclusive; overlap does exist among them. Nevertheless, these categories were used as a general guide in differentiating characteristics of issues for each case investigated.

Section 2.0 contains a technical discussion of energy storage alternatives for background. The cases reported on fall into two categories. The first, addressed in Section 3.0 of the report, covers instances where attempts to develop conventional pumped storage capabilities were thwarted for various reasons specified. These cases do not necessarily involve joint projects. The second group of case studies, reported on in Section 4.0, are those where jointly owned pumped storage projects have been constructed in the past or are under development.

Findings are summarized in Section 5.0. Additional observations and conclusions are contained in Section 6.0.

1.3 Acknowledgements

Pacific Northwest Laboratory wishes to acknowledge the kind assistance of numerous utility and research personnel in providing essential data, information, and advice for this project.

Table 1 shows a list of organizations and persons interviewed.

TABLE 1. ORGANIZATIONS AND PERSONS INTERVIEWED

Category	Organization	Person
Preliminary Interviews to Define Key Issues	Department of Energy	J. Swisher
	Pacific Northwest Laboratory	L. Kannberg
	Electric Power Research Institute	J. Birk
Personal Field Interview	Allegheny Power System	K. Bergmann
	Virginia Electric and Power Company	J.I. Oatts
		F.K. Moore
	Consumers Power Company	E. Kaiser
		R. Bonner
	Detroit Edison Company	R. Cline
	General Public Utilities Corporation	R. Ritchert
	Michigan Electric Power Coordinating Center	R. Gill
Telephone Screening Interview	Hunton & Williams	A. Quint
	Virginia Electric and Power Company	H.L. Engelman
	Consumers Power Company	G. Heins
	Commonwealth Edison	H. Nexon
	Public Service of New Mexico	B. Carrera
	General Public Utilities Corporation	E. Loane
	Appalachian Power Company	J. Plunk
	Appalachian Power Company	A.J. Dowd
	Consolidated Edison Company	W. Harkins

2.0 OVERVIEW OF ELECTRIC ENERGY STORAGE

2.1 General

Energy storage, the ability to "warehouse" energy as it is produced and retrieve it as it is needed, has long been recognized by utilities as a means of coping with the cyclical demand for electricity that fluctuates by time of day and season of the year. The benefits realized by the utilities who successfully incorporate storage systems into their generation, transmission, and distribution network are substantial. The major benefits are: coal and nuclear baseload plants displacing consumption of gas and oil in peaking and intermediate (cycling) generation power plants; increased flexibility in power system planning and operation; increased capacity factors of baseload facilities due to substitution; and lower forced outage rates and superior environmental characteristics of storage systems compared to conventional cycling units. Figure 1 graphically illustrates the benefits of energy storage by utilities.

The severe problems which have curtailed the development of pumped storage has spurred interest in the development of alternative load management technologies. The Department of Energy, recognizing the potential benefits of these load management technologies, is sponsoring a program of research and development of energy storage concepts which may replace or augment conventional pumped hydroelectric storage. Each of the technologies have some basic advantage over pumped storage but also have some technical uncertainties or problems which must be resolved before commercialization of the technology is feasible. The technologies being evaluated by DOE are Compressed Air Energy Storage, Underground Pumped Hydroelectric Energy Storage, Batteries, Superconducting Magnetic Energy Storage, and load management at the customer side. The following is a brief description of each.

2.2 Conventional Pumped Hydroelectric (CPH) Energy Storage

The first, and until recently the only, option available to electric utilities was the conventional pumped hydroelectric storage system. In this scheme water is pumped from a lower reservoir to an upper reservoir during periods of low demand and drops back through a turbine, generating peak power, during periods of high demand. This technology has worked extremely well and during the past two decades over 30 plants have been or are being constructed which can produce more than 13,000 MW of peak power. Figure 2 shows the CPH concept.

Because of the nature and diversity of pumped storage developments, various means of classifying pumped storage installations exist. For the purposes of this paper, consideration will be given to the "pure" pumped storage plants, those in which there is little or no natural inflow to the upper reservoir. There are two types of "pure" pumped storage plants. They are: the conventional pumped storage plant with both reservoirs located at the surface of the ground (the powerhouse may be located above or below the surface), and; the underground pumped storage type in which the lower reservoir is an excavated underground cavern.

Utility Storage

Figure 1

Figure 2

Pumped storage has been a means of supplying peak power in Europe since the turn of the century but growth in the United States was modest until the 1950's. With the development of a reversible pump-turbine having good efficiencies in both operating modes and the development of nuclear power, which provided excess least-cost baseload power during off-peak periods, the economics of pumped storage became evident and interest grew rapidly.

Table 2 shows pumped storage projects in use or under construction in the United States. Thirty pumped storage projects were completed between 1960 and 1980 but only three new plants are scheduled for completion by 1986. This decrease in pumped storage completions is the result of two primary factors, specific siting requirements and environmental opposition. These factors are discussed further in Section 3.0.

2.3 Underground Pumped Hydroelectric (UPH) Energy Storage

Figure 3 shows a sketch of the UPH storage concept. Underground pumped hydroelectric (UPH) storage has a potentially wider application than conventional pumped storage. The height difference between the upper reservoir at the earth's surface and the lower one underground could be several thousand feet compared to hundreds of feet in conventional pumped storage. The size of a reservoir holding an equal amount of potential energy can therefore be much smaller, and UPH is much less land intensive. A problem with UPH is finding sites of rock formation of sufficient strength and integrity to withstand the high water pressures. Reversible pump turbines that can handle the associated high pressures (up to 1500 psi) are still under development.

There has been some interest in UPH by utilities. Several feasibility studies have been completed but capital cost estimates are still somewhat greater than for conventional pumped storage. Even if abandoned mines are used (reducing the high excavation costs) UPH is still not competitive. Thus, even though UPH has some environmental advantages (reduced water requirement, less obtrusive) over conventional pumped storage, high cost remains an impediment to significant market penetration in the near future.

2.4 Compressed Air Energy Storage (CAES)

Figure 4 shows the CAES storage concept. This mechanical storage system has a potentially wider application than pumped hydroelectric storage due to its flexibility in siting and smaller minimum capacity. The strategy of CAES is to use off-peak electricity from nuclear and coal-fired baseload plants to compress air, which is stored in an underground reservoir. During the subsequent daytime peak load periods, the compressed air is withdrawn from storage, mixed with fuel, burned and expanded through the turbines to generate peak power. This concept reduces peaking plant fuel consumption by 60 percent because the compressor and turbine sections are alternately coupled to a motor/generator for operation during different time periods and the turbine is not required to drive a compressor during peak demand. Some advanced CAES concepts under development involve storage of the heat of compression in a thermal storage bed, thus eliminating the need for petroleum fuels.

TABLE 2. PUMPED STORAGE PROJECTS IN THE UNITED STATES

PLANT NAME	STATE	OWNER	REVERSIBLE CAPACITY(MW)
<u>In Operation in 1960</u>			
Rocky River	CN	Conn. Lt. and Power Co.	31
Buchanan	TX	Lower Colo. River Authority	11
Flatiron	CO	Bureau of Reclamation	9
Hiwassee	NC	Tennessee Valley Authority	60
		Subtotal	111
<u>In Operation in 1970</u>			
Lewiston	NY	Power Authority State of NY	240
Taum Sauk	MO	Union Electric Co.	408
Senator Wash	CA	Bureau of Reclamation	7
Yards Creek	NJ	Jersey Central Power & Light; Public Service Elec. & Gas	338
Cabin Creek	CO	Public Service Co. of CO	300
Muddy Run	PA	Philadelphia Electric Co.	800
Salina	OK	Grand River Dam Authority	130
O'Neill	CA	Bureau of Reclamation	25
Thermalito	CA	State of California	83
Edward Hyatt	CA	State of California	293
Smith Mountain	VA	Appalachian Power Co.	132
Seneca (Kinzua)	PA	Cleveland Electric Illum. Co. & PENELEC	422
San Luis	CA	Bureau of Reclamation	424
		Subtotal	3,602

TABLE 2. PUMPED STORAGE PROJECTS IN THE UNITED STATES
(Continued)

PLANT NAME	STATE	OWNER	REVERSIBLE CAPACITY (MW)
<u>In Operation in 1980</u>			
Mormon Flat	AZ	Salt River Project	49
De Gray	AR	Southwest Power Authority	28
Horse Mesa	AZ	Salt River Project	100
Northfield Mtn.	MA	Conn. Lt. & Power Co.; Hartford Elect. Lt. Co.; Western Mass Elect. Co.	1,000
Blenheim-Gilboa	NY	Power Authority State of New York	1,000
Ludington	MI	Consumer Power Co.; Detroit Edison Co.	1,872
Jocassee	SC	Duke Power Co.	612
Grand Coulee	WA	Bureau of Reclamation	300
Salina	OK	Grand River Dam Authority	130
Bear Swamp	MA	New England Power Co.	600
Carters	GA	Corps of Engineers	250
Raccoon Mountain	TN	Tennessee Valley Authority	1,300
Wallace Dam	GA	Georgia Power Co.	216
Harry Truman	MO	Corps of Engineers	104
Mt. Elbert	CO	Bureau of Reclamation	100
Castaic	CA	Los Angeles & State of California	1,200
Fairfield	SC	South Carolina Electric & Gas Co.	512
Subtotal			<u>9,373</u>

TABLE 2. PUMPED STORAGE PROJECTS IN THE UNITED STATES
(Continued)

PLANT NAME	STATE	OWNER	REVERSIBLE CAPACITY(MW)
<u>Under Construction, Application for License Pending, or Preliminary Permit Pending (Including Additional Capacity of Existing Plant)</u>			
Big Creek *	CA	Southern California Edison Co.	200
Prattsville *	NY	Power Authority State of NY	1,000
Boyd County *	NE	Nebraska Public Power Dist.	1,336
Milan ☒	NH	International Generation & Transmission Corp.	400
Oak Creek *	CO	Oak Creek Power Co.	3,600
Azure *	CO	Colorado River Water Conservation Dist.	240
Brumley Gap ☒	VA	Appalachian Power Co.	3,000
Rocky Mt.*	GA	Georgia Power Co.	675
Davis(2)	WV	Allegheny Power System	1,000
Bad Creek ☒	SC	Duke Power Co.	1,000
Helms +	CA	Pacific Gas & Electric	1,120
Smith Mountain(A)+	VA	Appalachian Power Co.	104
Harry Truman (A)+	MO	Southwestern Power Auth.	52
Clarence Cannon +	MO	Southwestern Power Auth.	31
Mt. Elbert +	CO	Bureau of Reclamation	100
Bath County +	VA	Virginia Elect. & Power Co.; Allegheny Power System ¹⁾	2,100
Seboyeta (F)	NM	Public Service Co. of NM	600
Subtotal			16,582

Total Potential Capacity by 1990 - 29,620

-
- (A) Addition to existing capacity
 + Plant under construction
 * Preliminary permit application pending with FERC
 ☒ Preliminary permit has been issued by FERC
 (F) No FERC licence required
 (1) Sale is pending. (2) License issued is under appeal.

Figure 3

Figure 4

CAES plants have flexibility in siting since the air storage reservoir can be of three different types: salt cavities, aquifers, or excavated hard rock. A critical unsolved issue that still remains is the behavior of large underground reservoirs subjected to daily pressure, temperature, and humidity cycling. There is little direct experience on the behavior of hard rock caverns, salt cavities, or aquifers when these are subjected to CAES operating conditions. Underground storage of hydrocarbon fuels and other fluids has been practiced for decades with good results. The geological competency of these storage media must be demonstrated before CAES assumes its place in the market.

Interest in CAES is already on the increase. The first commercial CAES plant is currently operating in Huntorf, West Germany. Some of the technical uncertainties are now being resolved as operational data is evaluated. This 290 MW plant began operations in December 1978 and its performance has equaled or exceeded design specification. In the United States, Soyland Power Cooperative, Inc. has filed and received exemption from restrictions of the Powerplant and Industrial Fuel Use Act (PIFUA) to construct a 220 MW CAES plant. Soyland's Board of Directors has authorized design and construction of the plant. Soyland hopes to complete the plant, which will use hydraulically compensated storage in hard rock, in 1985. Several other utilities are also known to be interested in CAES. It appears that a demonstration of the technical reliability in the United States might spur the widespread application of this technology.

2.5 Battery Energy Storage (BES)

Batteries could become an attractive alternative for daily cycle energy storage because of their potential for easy siting, operational flexibility, and short installation lead time. Conventional batteries (lead-acid) are far too expensive for large-scale application to modern power systems. Therefore, advanced batteries must be developed with lower initial costs and longer service life.

The Department of Energy (DOE) and the Electric Power Research Institute (EPRI) are currently investigating several systems with the potential of lasting 2000 or more cycles and costing less than \$50/kWh. Before commercialization of these systems is possible these batteries must still pass several technical hurdles. Among them are achievement of high efficiency, confirmation of the durability of battery reactive and containment material, establishment of adequate cell and multicell battery reliability, and development of truly low-cost manufacturing techniques.

The recent dedication of the Battery Energy Storage Test (BEST) facility in New Jersey is indicative of interest by the utility companies in this technology. BEST will be employed to evaluate battery prototypes with a storage capacity of 5-10 MWh in a utility environment. The availability of BEST might help overcome the technical and economic barriers inhibiting the commercialization of this technology.

2.6 Superconducting Magnetic Energy Storage (SMES)

The major advantage of Superconducting Magnetic Energy Storage is that electric energy is stored without conversion to another form. Efficiencies of greater than 90 percent are possible.

DOE and EPRI are studying conceptual designs of SMES systems. Useful installations would have to be extremely large, and the need for maintaining these systems at cryogenic temperatures raises great uncertainties of cost that have not been fully addressed. These cost uncertainties and the large size of SMES will postpone this technology as a reliable energy storage option until well after the year 2000.

2.7 Load Management at the Customer Side

The use of off-peak energy generated by baseload coal or nuclear plants for by consumers space heating, air conditioning, and hot water can be a cost effective method of leveling load peaks. Technologies exist such as timer-controlled electric hot water heaters, ceramic brick storage units for rooms, and floor slab heaters, which can be used. Since the burden of capital investment shifts to the customer, the utility must offer a lower off-peak electricity rate to create an incentive. Marketability is also constrained by the requirements for low cost, high reliability, and low maintenance equipment.

Experience in several European countries over the past 10 years has shown that customer load management works. In some parts of Germany, for example, electric storage heaters represent nearly 25 percent of the total demand for electricity, and in winter the daily load curve for a utility is almost flat. Various methods, including radio signals or signals carried by electric power lines, are being explored as a means to give utilities greater control over the load.

Prototypes of cool storage systems based on electric refrigeration to chill water or produce ice are now being tested. Such systems tend to be more bulky and expensive than heat storage systems but offer a greater potential payoff. Both DOE and EPRI are currently pursuing research on the most promising of these systems.

Electric vehicles, charged at night during normal off-peak periods, have the potential for influencing electric power load curves. The development of efficient, light-weight batteries and the implementation of low off-peak rates are the necessary keys to success.

Figure 5 shows several options for load management at the customer side. Utilities prefer to have the control and system flexibility of a central station storage facility. In some cases there is benefit to be gained by employing both end-use and central station storage technologies in tandem. Joint use of these storage options to maximize oil displacement, to level utility loads, and to provide service at the lowest possible cost to the customer can plausibly be achieved by some utilities. Specific results are dependent upon the individual utility service areas.

CUSTOMER-SIDE LOAD MANAGEMENT TECHNOLOGIES

Figure 5

3.0 SURVEY OF UNCOMPLETED STORAGE PROJECTS

3.1 Introduction

Information was collected on the following cases using telephone interviews with utility company executives. These cases consist of planned or partially constructed energy storage projects which were never completed. The situations involved, problems encountered, and characteristics of these projects are described.

In conducting the telephone survey, two major and recurring problem areas emerged. They were constraints of siting for energy storage facilities and opposition to facility construction by environmental and conservation groups. Each of these is discussed below followed by a somewhat more detailed discussion of each energy storage project surveyed.

3.2 Constraints Encountered

3.2.1 Siting Constraints

There are several specific primary criteria which need to be satisfied for a site to be technically suitable to build an economic pumped storage plant. The first is that there must be adequate height differential (head) between the upper and lower reservoir for generation of significant amounts of energy by falling water. Secondly, the upper reservoir must be of significant volume to provide enough water storage, and; third, the geology of the upper reservoir must allow for water storage without significant leakage. Other specifics must be factored in as well such as the ease of dam construction, accessibility of site, and adequate water availability. These specific criteria preclude the use of most areas of the United States for pumped storage development. There are many utility service areas which do not have adequate sites for pumped storage. The placement of current pumped storage projects indicate the most favorable sites are in the mountainous regions of the east, midwest, and west. There are no pumped storage facilities in the south or northern midwest areas. The site specificity needed for conventional pumped storage severely inhibits development in areas of the country which could derive benefits therefrom.

3.2.2 Environmental Constraints

Environmental opposition has become a large barrier to the construction and operation of some pumped storage plants. The consciousness of environmental issues that evolved in the 1970's has caused severe problems to utilities trying to license hydroelectric projects. Reasons for objection include destruction of scenic property and wetlands, reduction of fishing potential, damage to recreational areas, and the perception that proliferation of nuclear energy goes hand-in-hand with development of storage. The following are brief synopses of actual cases which typify the constraints to licensing of pumped storage plants.

3.3 Cases Surveyed

3.3.1 Blue Ridge and Brumley Gap

American Electric Power (AEP), through its subsidiary Appalachian Power Company, had proposed to build an 1000 MW pumped storage facility in the New River basin, on the North Carolina-Virginia border in Washington County, Virginia. A preliminary permit was filed for in 1962 and received in 1963 to perform studies to determine the feasibility of construction.

Several objections were filed by various groups but the major environmental request was made by the Department of Interior. The Department of Interior asked that large amounts of augmentation water flow be required by the license in order to counteract some significant pollution being caused by effluent release of some downstream factories in Charleston, West Virginia. This pollution dilution argument infuriated some environmental groups which insisted that pollution be stopped at its source and not "covered up" by increasing the amount of water flow. AEP also objected to this request since they would have to surrender some control of the facility and also the large flow would increase drawdown to where recreational use of the upper reservoir would be prohibited.

By 1968, AEP sought to modify its preliminary permit by moving the site upstream to a larger reservoir. The capacity of this site would have been 1800 MW. The site also had the advantage that the increased reservoir size would have allowed for recreational use because the drawdown on this larger reservoir was only 10 feet. The new site would have required the use of more land (approx. 40,000 acres) and this was vehemently opposed by several environmental groups.

At about this same time, a new administration in North Carolina opposed the project. This administration claimed that North Carolina would receive very few benefits since the majority of project works were in Virginia; yet much of the land to be inundated was in North Carolina.

Despite opposition of two of the three affected states, the Federal Power Commission determined the project to be in the public interest and granted AEP a license in 1974. The license had a stipulation that it would not take effect for approximately one year because Congress was considering passage of a Wild and Scenic River Act which would prohibit development on such rivers. This act was originally sponsored by North Carolina Congressmen and specified the South Fork of the New River, part of the Blue Ridge project, as part of the federal lands which could not be developed. Since this was part of this bill, the effect of the delay written into the license was to defer construction until the outcome of the bill was determined.

After approximately one year, the Wild and Scenic River Act was narrowly defeated and preliminary steps for the construction of the Blue Ridge facility were undertaken. One year later the Act was reintroduced and passed by Congress. This effectively cancelled the Blue Ridge project while preliminary work was underway.

American Electric Power filed suit in The Court of Claims for compensation, including lost future benefits, but this suit was denied. An appeal to the Supreme Court also was unsuccessful.

After losing the Blue Ridge site, AEP still had a need for peaking power and looked for new sites. The Brumley Gap site, a 3000 MW site in southwest Virginia, was determined to be suitable and an application for preliminary permit was filed in 1977. Opposition was encountered from a coalition of environmentalists, consumerists, and anti-nuclear forces. Nevertheless, a preliminary permit was issued in February, 1982.

The significant environmental opposition to pumped storage projects has obviously tempered AEP's bullishness on storage. Thus, utilities are looking toward other options for peak power generation.

3.3.2 Cornwall

Consolidated Edison Company of New York has proposed to build a 2,000 MW pumped project on the Hudson River near Cornwall, New York. A preliminary permit was granted for initial design. At this point, strong opposition surfaced from several environmental groups, but particularly from a coalition group called "Scenic Cornwall."

The original objection to the project was primarily aesthetic but the endangerment to fish in the area was also an issue. These intervenors caused significant delays in the project. After 1973, when electric demand in the post-oil embargo era reached a low, the project need became difficult to justify. Despite the opposition, a licence was granted and subsequently revoked.

Consolidated Edison's investment in Cornwall was about 38 million dollars. Consolidated Edison intends to appeal to the State Utility Commission to allow these costs in their rate base. Consolidated Edison has also agreed to drop all present and future plans to develop the Cornwall site in exchange for a 10 year settlement on cooling towers implementation on their Hudson River steam plants. This agreement was the final step in the death of the Cornwall project.

Future plans for storage at Consolidated Edison include the possible purchase of a portion of the Prattsville plant which is currently awaiting licensing for the Power Authority of the State of New York. Consolidated Edison is still recovering from the effects of Cornwall and has no plans for pumped storage development of their own.

3.3.3. Davis

The Davis pumped storage project, a 1000 MW facility, is proposed to be located in the Canaan Valley, West Virginia. Allegheny Power System, Inc. (APS), a holding company with three subsidiaries: Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, plan to construct and operate the plant. They filed for a license with the Federal Energy Regulatory Commission in 1970. A license was finally granted by FERC in 1977 which is now under appeal before the Circuit Court of the District of Columbia.

The Canaan Valley has unusual tundra-like vegetation and wetlands of approximately 30,000 acres. The proposed project would use over 7,000 of these acres. The problems encountered by Allegheny at Davis were due more to aesthetic than environmental reasons. This project was opposed by the Sierra Club, the Audubon Society, the Department of Interior, the State of West Virginia, and others.

A further complication arose; opposition to the dredging permit required from the Army Corps of Engineers. Since the Cornwall project had been halted due to dredging of the scenic Hudson River, environmentalists used this as a precedent in fighting the Davis project.

The environmental objection persists to this day. Allegheny Power System Inc. pursued other pumped storage options which culminated in an agreement with Virginia Electric and Power Company to buy a portion of the Bath County plant. This will fill the APS need for peak power in the near term but they still plan to construct the Davis plant to meet longer-term needs.

3.3.4 Kittatinny Mountain

The proposed Kittatinny Mountain pumped storage project is a 1300 MW facility located along the Delaware River basin between New Jersey and Pennsylvania. This is one of several proposed Delaware River Basin projects which includes the Tocks Island hydroelectric dam project.

General Public Utilities Corporation, a holding company representing Jersey Central Power and Light, Pennsylvania Electric Company, and Metropolitan Edison, proposed to construct and operate the Kittatinny Mountain project. The facility was dependent on the construction of the Tocks Island Dam.

The U.S. Army Corps of Engineers approved the project, but the Delaware River Basin Committee refused to grant the necessary permits for dam construction. The project has been indefinitely postponed. The Committee claims that the waterway is a wild and scenic river protected by law. At the present time, Congress has authorized the project, but a final decision on river development projects is pending federal and state approvals.

4.0 SURVEY OF JOINTLY-OWNED STORAGE PROJECTS

4.1 Introduction

In order to best determine the problems associated with the ownership, particularly joint-ownership, of large-scale storage facilities, case studies were conducted of various conventional pumped storage plants. Since there are over thirty pumped storage plants of varying sizes, characteristics, and ownerships, specific criteria were used to select the four projects that would eventually provide the best information.

The field was initially narrowed by including only plants which had more than one owner. This allowed us to uncover problems which were germane to joint-ownership as well as those of storage in general. Co-ownership is not a clearly defined concept when dealing with the utility industry. Some plants may be co-owned by three or more utility companies which are under the umbrella of a holding company. An example of this is the Northfield Mountain pumped storage plant which is owned by Northeast Utilities, whose members are Connecticut Light and Power Company, Hartford Electric Light Company, and Western Massachusetts Light Company. Plants such as this were eliminated from the study plan since these projects were planned by a single company.

Federal Government projects were not considered since these do not undergo the same regulation as those proposed by investor-owned utilities. Projects by the Army Corps of Engineers, Bureau of Reclamation, Southwestern Power Authority, etc., are affected by a different regulatory, financing, and legal climate which is beyond the scope of this survey.

After screening the remaining projects, four plants, stood out as candidates for investigation. These four plants, Yard's Creek, Seneca (Kinzua), Ludington, and Bath County have varied sizes, construction dates, ownership arrangements, and locations (Figure 6). A case study of these plants has the potential for uncovering virtually all problems associated with the ownership of large-scale storage facilities. Although each of these plants is a pumped hydroelectric storage plant, each is unique.

Yards Creek, a 338 MW plant completed in 1965, is 50 percent co-owned by Jersey Central Power and Light (a General Public Utilities, Inc. subsidiary) and Public Service Electric and Gas Company. This project was the first co-owned pumped storage facility in the United States and offered an important perspective of the problems, both technical and management, that occurred in the early 1960's. The project was the largest of its time and was a milestone in the history of pumped storage projects.

The Seneca (Kinzua) pumped storage project was completed in 1970 and is co-owned by Cleveland Electric Illuminating Company (80%) and Pennsylvania Electric Company, another subsidiary of General Public Utilities, Inc. (20%). The plant is slightly larger than Yard's Creek (422 MW). The unique features of this plant are the unusual ownership agreement (80/20) and the fact that the plant was built as a private venture on Federally owned lands co-sited with a flood control dam. This project adds an interesting perspective on complex negotiated agreements involving both federal and private parties.

MAJOR JOINTLY-OWNED PUMPED STORAGE PROJECTS

Figure 6

The Ludington pumped storage plant is a landmark engineering achievement as well as a milestone for coordination of a joint ownership agreement. The Ludington facility is co-owned by Consumers Power Company (51%) and Detroit Edison Company (49%) and is 1872 MW in size. Since the capacity of the plant was far in excess of the needs of its two owners when the plant was finished in 1973, Commonwealth Edison Company of Illinois signed a lease for a one-third share of the plant through 1983. This unique lease arrangement offered another interesting perspective on the ownership of a storage plant. The coordination and dispatch of energy to and from the plant is coordinated through the Michigan Electric Power Coordination Center, a powerpooling type arrangement initiated by Consumers Power and Detroit Edison. These unique features made it both necessary and worthwhile to study this agreement.

The final project investigated is the Bath County pumped storage project owned by Virginia Electric and Power Company (VEPCO). The Allegheny Power System Companies have agreed, subject to approval, to purchase a share of the plant. This 2100 MW plant is scheduled to begin operation in 1985. This plant was originally begun as a solely-owned project. VEPCO sought a partner after construction had begun, a unique feature of this project. In contrast to Brumley Gap, less opposition was encountered to the licensing and construction of this plant. The study of this project should be useful to utilities considering large-scale storage.

An important component of this survey is the information obtained by interviews with utility executives and planners, as well as with government and industrial spokesmen. Utility representatives responsible for bringing the four jointly-owned pumped storage projects on line were contacted. Technical, economic, regulatory, institutional, and environmental issues were identified.

The issues were discussed with utility representatives in terms of implementing joint ownership arrangements on a wide scale. The possibility of regulatory reforms, advantage of second generation systems (CAES or UPH), creative financing, for example, are described in Section 4.0 and analyzed in Section 5.0. Conclusions and recommendations for future directions in large-scale utility storage are then presented in Section 6.0.

These four pumped storage projects are intended to represent the spectrum of large-scale storage facilities that are available for investigation.

4.2 Yards Creek Pumped Storage Plant

Yards Creek Pumped Storage Plant was the first conventional storage project in the United States jointly built by two public utilities. Located in northeastern New Jersey, the plant is owned by Public Service Electric and Gas Company of Newark, New Jersey and Jersey Central Power and Light Company of Morristown, New Jersey (a subsidiary of General Public Utilities). Management practices established by this joint agreement helped set precedents for future agreements governing jointly-owned storage projects. Since both Jersey Central and Public Service belong to the Pennsylvania-Jersey-Maryland

Interconnection System (PJM), the benefits of incorporating a storage plant in a centrally operated system were demonstrated by this project.

4.2.1 History

Jersey Central Power and Light and Public Service had worked together on a number of projects prior to Yards Creek, and the joint ownership of a storage plant posed no serious problems. Their service areas are contiguous, with Jersey Central servicing the western areas in north Jersey and Public Service operating in the eastern areas. The transmission system in northern New Jersey was also adequate to handle the increased loads on the system due to Yards Creek.

As members of the PJM System, the utilities derive maximum benefits of reliability and economy from the centralized operation of generation, storage, and transmission facilities. Both utilities are confident that economic benefits are realized from PJM control and dispatch of the plant.

4.2.2 Project Planning, Negotiations, and Joint Agreement

Although Jersey Central was the original owner of the project lands, by the agreement negotiated between the utilities, each utility owns 50% of the project. Project costs and pumping requirements are shared according to this ownership ratio. Since the project lies in the area serviced by Jersey Central Power and Light, they are the designated operator of the plant. Plant operation is scheduled by the PJM System.

4.2.3 Plant Licensing

In March, 1963, the Federal Power Commission issued a joint license to the utilities for the Yards Creek Plant. The Commission found that the Yards Creek Project was the first stage of the utilities' plan to develop the energy resources of the Delaware River area. Further development by these utilities included the Kittatinny Mountain Project and the Tocks Island Project. Although the Yards Creek project is virtually independent of other projects in the Delaware River watershed, the Commission mandated that future development of projects must be carefully coordinated with the Yards Creek project by Public Service and Jersey Central.

No environmental protests against the project were recognized by the Commission.

Plant operation began in 1965, and no management problems have arisen due to joint operation or integration of the plant in the PJM System. Yards Creek has been temporarily shut-down for maintenance several times, but since the technical problems have been corrected, plant operation has continued uninterrupted.

4.2.4 Issues Affecting the Project

Yards Creek, unlike subsequent storage projects, did not encounter serious environmental or regulatory opposition during the licensing stage. Pumped storage was a proven technology in the United State since the 1950's, and Yards Creek did not incorporate any new or advanced techniques. Since the utilities had a history of good working relationships, negotiating the agreement for the project was conducted expediently. Besides Federal approval for the project, a joint application to the state was approved without delay. The success of the joint project, with respect to licensing and operation of the plant with the PJM System, has set a precedent to encourage other joint projects.

4.3 Seneca (Kinzua) Pumped Storage Project

The Seneca Pumped Storage Plant in western Pennsylvania is located in the service area of Pennsylvania Electric Company. Cleveland Electric Illuminating Company of Ohio owns 80 percent of the plant and Pennsylvania Electric Company owns 20 percent. Cleveland Electric is primarily responsible for plant dispatching and operation. The Seneca project is an important case study because it offers valuable information on interstate ventures and the issues related to private development of federal lands. The plant was built at a site already developed by the U. S. Army Corps of Engineers in the Allegheny National Forest.

4.3.1 History

General Public Utilities Corporation (GPU) is a major public holding company with three subsidiaries; Metropolitan Edison, Pennsylvania Electric Company (PENELEC) and Jersey Central Power and Light. The GPU service area includes parts of eastern and central Pennsylvania and the northwestern area of New Jersey. As previously discussed, GPU belongs to the PJM Interconnection System.

When PENELEC first planned the Seneca plant and presented their plans to the PJM System, the System discussed keeping the project completely within the power pool by sharing the Seneca plant with another PJM utility member. No utility member, however, could justify the need for peaking power and GPU did not have an immediate need for the full capacity of this plant. GPU had recently brought the Yards Creek pumped storage project on line and it was anticipated that future peaking needs could be met by two other planned storage projects included in their system planning, the Kittatinny Mountain and the Longwood Valley Project. Environmental problems years later forced GPU to indefinitely postpone Kittatinny Mountain and cancel the Longwood Valley project; but during the Seneca planning stages, GPU was confident of its future strategy to meet peak demand. Consequently, when an independent partner was sought, PENELEC assumed only a small ownership interest in the plant.

The project site is at the Kinzua Dam on the Allegheny River in western Pennsylvania. Constructed by the U.S. Army Corp of Engineers, the dam

is used primarily for flood control and for recreational purposes. The Corps of Engineers continues to exercise jurisdiction over this area. During construction of the flood control project, the Corps anticipated that the dam could be used in the future for hydroelectric power and portals for generation units were included in the dam structure.

GPU wanted to take advantage of this site for a pumped storage project since the federal government had forfeited their interest in developing the dam for power generation purposes. PENELEC and the PJM members preferred to utilize the site at this time rather than lose the opportunity to develop the Seneca Pumped Storage project. For this reason, Seneca became a priority for the utilities even though system planners for GPU and PJM felt that demand for additional capacity in the next decade was uncertain.

4.3.2 Project Planning and Negotiations

PENELEC discussed sharing the project with the Allegheny Cooperative in September 1960. Allegheny Cooperative is composed of a number of federally financed cooperatives in Pennsylvania and New Jersey. One of their members, Warren Electric Cooperative, negotiated with PENELEC to develop the dam area as a two stage project. Warren was to build a conventional hydroelectric project adjacent to the dam and PENELEC would build the Seneca Pumped Storage Project to use jointly with Warren.

Before preliminary studies commenced, Warren suddenly pulled out of the agreement. PENELEC continued with their site investigations and began negotiating with another interested party, Cleveland Electric Illuminating Company (CEI) in Ohio.

Cleveland Electric Illuminating Company services the Cleveland area in northeastern Ohio. They are a member of the Central Area Power Coordination Group (CAPCO) which was established in 1967 to improve interconnection facilities and to assure more economic operation of system generators. A number of joint coal and nuclear power plants were planned by the power pool to supply low-cost power throughout the 1970's and 1980's and a pumped storage plant would provide increased peak power in their system.

PENELEC's offer to jointly own the Seneca Pumped Storage Plant was timely since Cleveland Electric needed peaking capacity, and they could supply the baseload power to pump the plant. Their membership in the CAPCO power pool also assured economic operation of the plant since the most inexpensive power could be used to pump Seneca, and the entire coordination system could utilize the peak power.

4.3.3 Joint Agreement

In preparation for filing the application with FERC, the two utilities negotiated a joint agreement. According to the agreement CEI would own 80 percent of the Seneca plant and PENELEC would own 20 percent. PENELEC's share is considerably less than CEI's ownership interest due to their

confidence in two other planned storage projects that were intended to supply peaking power in the 1970's. PENELEC now speculates that a greater ownership share would have been advantageous, but a lease or capacity purchase excess capacity was never considered. Moreover, this pumped storage plant was the first project Cleveland Electric Illuminating Company had ever built outside its service area and CEI wanted a firm partnership in the plant. Although Cleveland Electric has a larger share, PENELEC's initial role in the planning efforts made them more suitable to be the lead utility in the licensing procedures.

4.3.4 Plant Licensing and Operating Agreement

In 1964, Cleveland Electric and PENELEC filed a joint application with the FPC for the licensing of the 422 MW Seneca Pumped Storage Project. The plant was designed for the maximum capacity possible for the site. A joint license was granted in December 1965 and construction began in April 1966.

The only problem that the utilities faced in the licensing period was opposition to the project by the Warren Electric Cooperative. Although Warren Electric did not justify their withdrawal during the planning stage, subsequent protests by the Cooperative during the licensing of the Kinzua project by Cleveland Electric and PENELEC revealed that Warren Electric preferred that the Federal Government, not a private utility, develop the project. Although Warren Electric received support from the Department of Interior and the Department of Agriculture, FPC overruled their opposition and granted the license with minimal delays.

Unlike other licensing procedures where a utility holding company is involved, the Seneca plant was licensed by PENELEC, not by GPU. This arrangement does not circumvent Securities and Exchange Commission approval, but state approvals needed to be secured only in states serviced by PENELEC, not by all subsidiaries of GPU. PENELEC required state approvals from Pennsylvania for the Seneca plant, but not from New Jersey which is serviced by another subsidiary of GPU. Similar arrangements may help ease licensing delays in the future. Although the subsidiary was the licensee, the overall load characteristics for all of the subsidiaries can still be used to justify the project.

The Seneca project location at the Allegheny Dam site is advantageous to the utilities for numerous reasons. Both the Kinzua Dam and the lands used for the reservoir are part of the Allegheny National Forest and are under the jurisdiction of the Federal government. Consequently, GPU did not have to secure private land for the project. GPU did obtain transmission line right-of-way in the area. According to the terms of the FERC license, Cleveland Electric and PENELEC pay an annual fee to the U.S. Government for use of the water, the dam and the federal lands. While this arrangement may not have guaranteed a cost savings, the company avoided negotiating for land rights with private citizens. The use of Federal lands, especially those already screened for Federal projects, can help facilitate the licensing process.

In addition to the annual fees specified in the license, a Memorandum of Understanding between the U.S. Army Corp of Engineers and PENELEC was signed to allow for efficient and safe operation of river projects. A unique feature of this project is that water used for power generation can be discharged either behind the dam or downriver, depending on the flow level at the time. Minimum discharges from the Kinzua Dam are required for flood control and recreational purposes. Under the terms of the license, the Seneca Pumped Storage Plant schedules plant operation to maintain a steady flow rate in the downstream release.

The joint ownership of the Seneca Pumped Storage Plant has been mutually satisfactory for both Cleveland Electric Illuminating Company and Pennsylvania Electric Company since operation began in December, 1970.

The operation and scheduling of the Kinzua plant is the responsibility of Cleveland Electric. PENELEC, through the PJM System, coordinates pumping and generation with the operation schedule established by Cleveland Electric. Since there is little difference between system needs for the two utilities, operation problems are minimal. Even if Seneca is operating in the generating mode and PENELEC does not want generation power at the time, PENELEC's 76 MW is such a small share of the system capacity that power can be utilized in the system with no problems. PENELEC's small 20 percent share allows operation of the Seneca Plant to be flexible and relatively uncomplicated. If PENELEC owned a greater percentage of Seneca, or if the plant was larger, more serious problems may have arisen from this type of operating agreement.

4.3.5 Issues Affecting the Project

4.3.5.1 Power Pools and Joint Projects. Most utilities believe that pumped storage can be utilized most effectively when it is tied into a power pool or an interconnected grid network like the PJM system. These coordinated power groups also jointly plan and operate large, capital-intensive projects and therefore the cost risks and benefits are shared by member utilities.

Power pool membership is advantageous during plant licensing, especially for joint projects, because the total capacity and load of the power pool can help justify large capacity plants that may not be needed now, but will be needed after the long licensing and construction period. Unfortunately, power pool members often face difficulties satisfying individual members when one member's excess power or reserve capacity is incorporated into another member's storage plans, while alternative uses are already planned for the excess power by the former. The subsidiaries of GPU have not encountered this potential problem, although the recent decision by GPU and Pennsylvania Power and Light to investigate possible sites for a new storage plant against a PJM committee's recommendations may precipitate problems.

4.3.5.2 Storage vs. Conventional Peaking Technologies. Given the system demands of GPU and Cleveland Electric Illuminating Company, pumped

storage provided lower-cost peak power for both utilities in the 1970's. The plant supplies energy at a lower cost than an oil or gas turbine. The only other peak power generation unit competitive with a pumped storage plant today is a cycling coal generator; because environmental constraints have been relaxed on coal units. Pumped storage plants are also at a disadvantage relative to coal generators because of longer licensing and construction periods. The decisive factor influencing the type of peaking technology utilized is always economic benefits. This criteria was applied in the 1960's and continues to be used as the primary consideration for all construction programs today.

Central station storage projects such as pumped storage are usually large plants which are situated away from the load center of a system. With joint projects, the plant may be more decentralized and at a greater distance to utilities' service areas. Some groups believe that securing right-of-ways can escalate the project costs significantly. During the planning stages of the Seneca project, Cleveland Electric and GPU found that the joint project required only as much new transmission facilities as a baseload plant of equal size. Transmission line costs for joint projects are generally minor because the utilities are well interconnected. A joint plant, contiguous to both utility service areas, can be readily interconnected into the systems.

For the Seneca project no major additions to the interconnection system were required. The existing transmission lines in the area were improved and expanded and tie lines into the plant were constructed. The interconnection system linking PENELEC and Cleveland Electric was adequate for power purchases between utilities, and no additional lines were needed to accommodate the increased power in the area due to the Seneca Plant. PENELEC's Glade Switchyard Station monitors power for the Seneca Plant and accounts for each utility's share of power for pumping and generation. The Glade Switchyard controls large amounts of energy, not only from the Seneca Plant, but from throughout PENELEC's system.

4.3.5.3 Storage and Load Management. Like many other utilities, both GPU and Cleveland Electric believe that central station storage and dispersed storage methods are necessary for efficient and cost-effective management of system loads. Customer side load management methods can also benefit the customer with electricity savings and help the utilities manage their load peaks. Due to the sizable risks associated with large central station storage, utilities often encourage load management with customer participation. Since only state authorities approve these technologies and associated rates, implementation can be rapid and less costly. Metropolitan Edison, for example, offers voluntary time of day rates and timers on electric hot water heaters. Thermal storage heaters are also under consideration as a load management technique. Customer-side load management and large-scale storage facilities tend to enjoy a synergistic, not a competitive, relationship. Many utility planners believe a combination of customer-side load management and pumped storage provides the best flexibility for managing fluctuating demands.

Although neither GPU nor Cleveland Electric requires a pumped storage unit at the present time, GPU has screened a number of possible sites in

Pennsylvania that are suitable for a storage plant. In addition to conventional pumped storage, GPU also seriously considered underground pumped hydro storage as a peaking power source. An abandoned iron ore mine in Mt. Hope, New Jersey has been chosen as a feasible site, and engineering design plans call for use of the original mine shafts and excavation of water storage areas. While GPU was processing the license with FERC, the mine owner revoked the property lease which forced cancellation of the project.

GPU's interest in UPH remains strong although company officials acknowledge that UPH is not more economical than conventional pumped storage projects. There are advantages with an underground system, since projects can be located near major load centers and environmental intrusions can be minimized. FERC recognizes these benefits, yet they may challenge UPH licenses on the basis of higher costs. The economic advantages of alternative storage or peaking generators support the use of conventional methods rather than advanced technologies.

4.3.5.4 State and Federal Regulatory Issues. State and Federal agencies play an active role in licensing projects and establishing utility rates, but their role does not extend to the planning sphere. System planning is the responsibility of the utilities. They coordinate the power purchases and the joint agreements between neighboring utilities. The success of joint agreements, especially the agreement between Cleveland Electric Illuminating and PENELEC, is due to the initial work of utilities to integrate planning activities and only secondarily to the actions by state commissions and FERC in the licensing stage. If any group is to assume responsibility for encouraging joint projects, it must be the public utilities and not the government.

One problem that plagues almost all pumped storage projects, both during construction and for years after start of operation, is the fish and wildlife restoration issue. GPU continues to encounter opposition at Seneca and their low-head hydro projects. They fear that environmental problems, such as the fish and wildlife preservation question, will threaten any new pumped storage or conventional hydro project under consideration. At the Seneca plant, the Corps of Engineers maintains the recreational facilities and fishing areas at the Kinzua site. The Corps also conducts environmental studies in the area. Rather than duplicate work, the utilities do not sponsor independent analyses, but help to finance the Corps' work. This may minimize the utilities involvement in mitigating environmental damage, but the issues are still controversial and require serious investigation.

4.4 Ludington Pumped Storage Plant

The Ludington Pumped Storage Plant on the eastern shores of Lake Michigan is the largest pumped storage project in the United States. Jointly owned by the Consumers Power Company and the Detroit Edison Company, the Ludington plant began operation in 1973, and was acclaimed as a major engineering accomplishment. Ludington merits close study due to the extensive planning arrangements for the 1872 MW project and the leased interest of Commonwealth Edison in the pumped storage plant.

4.4.1 History

Consumers Power Company and the Detroit Edison Company are the major utilities servicing the state of Michigan. The working relationship between these two utilities began in the 1920's. In 1928, Consumers Power and Detroit Edison established a low voltage interconnection link between their service areas. This interconnection link was established only for emergency needs and the companies remained virtually independent for three decades. It was not until the 1960's that the utilities coordinated their planning efforts and operating activities.

4.4.2 Project Planning and Negotiations

A coordination agreement between Consumers Power and Detroit Edison was concluded in 1962 to provide for joint power supply studies and to establish priorities for expanding both utilities power systems. Included in this agreement were plans to continue with Consumers Powers initial investigations of a pumped storage plant to meet the future peak generation needs of both Consumers Power and Detroit Edison. Consumers Power had already launched a program for site selection in the late 1950's and a 1958 Fargo Engineering study specified a number of potentially suitable sites.

A site on Lake Michigan near Ludington was selected as the most attractive due to its good soil conditions and its proximity to numerous ports on the lake. When the Fargo Engineering study was completed, Consumers Power initially considered developing the Ludington site for a 500 MW pumped storage facility that they would independently own and operate. These plans were included in the Michigan system analyses, but feasibility studies conducted in the early 1960's showed that Ludington would not be economically competitive with alternative peak power generation methods until the interconnection system in Michigan was improved. At this time, Michigan's lack of an extra high voltage transmission grid made coal-fired units the most cost-effective peaking units. Consequently, Consumers Power was forced to postpone plans for a pumped storage plant until the high-voltage transmission system was constructed.

The necessary prerequisites for interconnecting the power system in Michigan were achieved in 1962 when Consumers Power and Detroit Edison concluded the coordination agreement. The Ludington project was again studied by the utilities and by Ebasco Engineering Corporation of New York. Development plans for the utilities included a high voltage grid interconnecting the two utility service areas, and connections with neighboring utilities in Canada, Indiana and Ohio. New generation facilities such as fossil-fired and nuclear power plants were also included in the expansion plans. These large base-load plants, when coupled with the extensive transmission grid, give Detroit Edison and Consumers Power the off-peak power and the transmission network necessary to operate a pumped storage system economically.

With the completion of the high voltage transmission grid in 1969, Consumers Power and Detroit Edison jointly established the Michigan Electric

Power Coordination Center (MEPCC). The MEPCC was not intended to be a power pool, but a fully interconnected system to centrally dispatch and operate the entire generating capacity of both the Consumers Power and the Detroit Edison electric systems. By integrating the Ludington plant with the MEPCC, advantages in operational efficiency and cost savings could be achieved.

During the expansion of the transmission system, Ebasco Engineering conducted feasibility studies for the MEPCC and concluded that future load predictions supported developing the Ludington site to its maximum capability of approximately 2000 MW. Although the Michigan system could not utilize this total capacity until 1983, the two utilities decided to build the largest size plant possible in order to capitalize on the opportunity to meet the predicted electricity demands in the 1980's. The decision was also supported by the immediate peaking power needs of neighboring utilities. The Commonwealth Edison Company of Chicago expressed strong interest in the project early in the planning stages. Although Detroit Edison and Consumers Power did not want to bring a third utility into the ownership agreement, they were confident that arrangements could be made to lease at least 1/3 of plant capacity until the additional peaking capacity was needed in the mid 1980's.

The Commonwealth Edison Company had been interested in the Ludington plant from the time the project was first included in the Michigan systems studies. Commonwealth Edison had seriously considered building a storage project to meet increasing peak demand, but their Illinois service area is primarily flat plains which are unsuitable for a pumped storage project. Their initial offer to Detroit Edison and Consumers Power was to purchase 1/3 of the plant capacity.

The Michigan utilities refused this offer since they wanted to maintain full plant ownership. Both Consumers Power and Detroit Edison were financially stable and construction costs could be financed with company assets and loans. A third partner was not needed to help finance the project. In addition, both utilities were experiencing an 8 percent load growth and they expected to utilize the full plant capacity by 1985. For these reasons, Consumers Power and Detroit Edison declined Commonwealth Edison's offer and negotiated a capacity purchase agreement.

4.4.3 Joint Agreement and Leasing Agreement

The joint ownership agreement specifies that Consumers Power assume 51 percent ownership and Detroit Edison assume 49 percent ownership. Capital costs and operating costs are divided according to this ratio. Due to their familiarity with the Ludington project, Consumers Power assumed the lead role in the licensing procedures with the Federal Energy Regulatory Commission (FERC) and the state utility commission.

The original leasing arrangement with Commonwealth Edison planned by the Michigan companies was a ten year lease for 1/3 of plant capacity from 1973 to 1983. Since Commonwealth's offer to jointly own Ludington was refused, the Michigan utilities compromised on their lease specifications, and extended the Commonwealth Edison lease for 1/6 of plant capacity for five additional years, from 1983 to 1988.

4.4.4 Plant Licensing

Ebasco Engineering Corporation of New York conducted the final cost studies and technical analyses for the Ludington plant in 1967 and 1968. A FERC license application was filed in June 1968 and the license was granted in July 1969. Construction began immediately and was completed on schedule in 1973. From the initial site studies until final plant operation, the Ludington Pumped Storage Project required fifteen years to plan, license and construct.

In addition to the license requirements specified in the Federal Power Act, the joint license granted by FERC also approved Commonwealth Edison's capacity purchase lease in the Ludington plant. This lease agreement with Commonwealth Edison was a major factor in the utilities' justification for building the 1872 MW plant. From FERC's perspective, Commonwealth Edison's lease in the Ludington plant allowed the customer's best interest to be served by developing Ludington to its maximum potential for long term economic savings.

The information suggests that FERC initially allowed Detroit Edison and Consumers Power to overbuild since the excess capacity could be utilized by a neighboring utility, who was not an owner in the project. In this case it appears that FERC believed that the penalties of developing a project site to the maximum potential are less than the penalties associated with using alternative peaking technologies.

4.4.5 Operating Agreement

The operating agreement among Commonwealth Edison, Consumers Power and Detroit Edison has been mutually satisfactory to all three utilities.

The Michigan Electric Power Coordination Center schedules the system for Detroit Edison and Consumers Power, including the pumping and generation of the Ludington plant (including Commonwealth Edison's interest). If one utility needs to generate and another wants to pump then "water credits" or capacity credits are given according to the power accepted into the MEPCC System. Incorporating a pumped storage plant in a system like the MEPCC is the most efficient way to pump and utilize generation capabilities since the most inexpensive energy from baseload generators and power purchases can be used as pumping power and peak energy can be supplied at cost-competitive rates. Scheduling plant operation has posed no serious problems for the MEPCC since the three utilities have similar load profiles and the utilities are large enough to maintain a regular operating schedule.

Commonwealth Edison pays a fixed annual charge to the MEPCC for the use of the plant and also assumes responsibility for 1/3 of the annual operating and maintenance costs. Since Commonwealth must transmit power through Indiana, Commonwealth also pays American Electric Power for the use of their transmission system in northern Indiana and assumes the costs for transmission power losses until the power enters or leaves the MEPCC service area. Commonwealth Edison supplies its own pumping power and reclaims this stored

energy during plant generation periods. Pumping and generation are scheduled by the MEPCC and Commonwealth Edison coordinates their needs with the MEPCC schedule. The schedule is usually established for a given weekly period with minor modification made one day prior to an operating period.

Commonwealth Edison has encountered little difficulty coordinating their system with the MEPCC. In the event that Commonwealth wants to pump and the MEPCC has not scheduled pumping, capacity credits or water volume credits are given to Commonwealth Edison and the electricity is utilized in the Michigan system. One requirement specified by the MEPCC is that Commonwealth provide power to pump at least one unit during pumping periods. If the MEPCC also wants to pump, but neither Commonwealth or the MEPCC have enough power capacity to individually pump a second unit, the utilities will operate a unit together.

4.4.6 Issues Affecting the Project

4.4.6.1 Load Matching. Teaming utilities up to share a storage plant is not a major issue, especially for utilities in neighboring service areas. Contrary to belief, utilities do not require significant seasonal diversity in their load profiles. For example, Detroit Edison is summer peaking while Consumers Power was winter peaking in the 1960's and is now a summer peaking utility. Even with Commonwealth Edison's sharp summer peaking load profile, the Ludington plant and its associated coordinated distribution system can accommodate the demands of all three utilities.

4.4.6.2 Joint Projects and Independent Utilities. The joint operation of the Ludington plant and the central coordination of system generators improved the relationships between major utilities, municipal, and cooperative power companies in the Michigan area. A pumped storage facility, especially a large unit integrated in a comprehensive transmission grid, helps independents utilize their off-peak baseload power. Independent utilities have worked extensively with Detroit Edison and Consumers Power. During the preliminary planning stages for Ludington, the independents were offered the opportunity to lease capacity in Ludington. Although these groups did not, their indirect use of the plant through power purchase agreements with Consumers Power and Detroit Edison provides the independents with markets for their excess baseload power and lower-cost power for peak times.

4.4.6.3 Storage and Load Management. Some utilities believe that customer-side load-management technologies may provide increased benefits when utilized in a system with central station storage. Both Detroit Edison and Consumers Power have experimented with various load management techniques for peak leveling and intend to expand their plans in the future. Detroit Edison currently uses time-of-day pricing and regulates hot water heaters by radio control. They are also involved in government studies on wind turbines and numerous solar energy projects. Consumers Power has experimented with thermal heat storage in bricks and hot water heating control. However, rate changes

were necessary to encourage use of these technologies. Both Detroit Edison and Consumers Power have applied to the Michigan Public Service Commission for permission to expand their experimental programs.

4.4.6.4 State and Federal Regulatory Issues. Detroit Edison and Consumers Power, with the MEPCC, work closely with the Michigan Public Service Commission. Although FERC regulates interstate power sales and power purchases associated with the Ludington plant, the MEPCC keeps the state commission up-to-date on their activities with FERC and neighboring utilities in order to ease regulatory approvals for all Detroit Edison and Consumers Power rate changes. Both utilities believe that this open relationship with the state commission has benefited them.

The Ludington plant is included in the rate base for each utility according to the percentage of ownership. Both the Illinois and Michigan Public Service Commissions treat the capacity purchase agreement as a power purchase transaction, not as a lease or temporary sale of plant capacity. Consequently, power purchase revenues from Commonwealth are included in the Michigan utilities revenues for tax purposes.

FERC has jurisdiction over any modifications in the joint license for the Ludington plant. The joint license includes approvals for the Commonwealth Edison lease, which expires in 1988. According to the license, Detroit Edison and Consumers Power will require available peaking capacity by 1985. At the present time, however, the recessionary climate has reduced load growth and the peaking needs of the MEPCC and load growth is considerably below the predicted values. Neither Consumers Power or Detroit Edison need additional peaking power at the present time. Currently, their loads are flattening out. Consumers Power is experiencing 70 percent load factor and both utilities have sizable reserves. If Consumers Power and Detroit Edison renegotiate the lease with Commonwealth Edison or with another utility, FERC will exercise regulatory authority and review the new capacity purchase agreement. Many utilities fear that FERC will modify their license or reevaluate a certain article of the license. In the Ludington case, no unusual problems are expected with a new lease agreement.

Two major recurring problems associated with regulatory approvals for the Ludington plant have been the requirements established by FERC and the Michigan Department of Natural Resources to mitigate fish loss and erosion damage to the Lake Michigan bluffs. Fisheries on Lake Michigan and in area rivers have been studied since construction began in 1969. To date, no final decision has been made on how to best develop and maintain fish populations near the Ludington site. The utilities have also encountered an active local coalition to prevent bluff erosion on Lake Michigan. Although the most recent studies conclude that the pumped storage plant does not adversely affect bluff erosion, the utilities fear that additional studies may be mandated. Environmental and aesthetic problems can be a constraint to project development and operation, and the Ludington project, eight years after operation began, is still actively encountering these constraints.

4.5 Bath County Pumped Storage Plant

The Bath County Project in Virginia has been under construction since 1977 and is expected to be completed by 1986. Virginia Electric Power Company (VEPCO) owns the facility, but negotiations have recently been completed to sell part of the plant to Allegheny Power System subject to regulatory approval. Unlike the three previous storage projects, Bath County has been subject to more detailed licensing procedures, including National Environmental Policy Act (NEPA) approvals. Further problems involving load forecast and financing have delayed construction schedules which will result in escalating construction cost. Due to the unique nature of the planning and ownership arrangements for the Bath County plant, this project provides information on opportunities for new joint storage ventures.

4.5.1 History

In the early 1960's, VEPCO recognized that a pumped storage hydro-electric project would be the most economical way to meet their increasing peak load demands. VEPCO was also planning additional baseload nuclear and coal-fired plants to meet the 10% load growth figures projected for the next two decades. A pumped storage project could utilize the off-peak baseload power and generate low cost energy during peak demand periods. For these reasons, VEPCO launched an aggressive program for a pumped storage plant and began site investigations. The first site that was seriously studied by VEPCO was the Marble Valley site in western Virginia which was suitable for a 1000 MW plant. A preliminary permit was granted by FPC to investigate the site, but geological studies showed that the upper reservoir would be unsuitable for containment due to limestone formations in the reservoir area. Plans for a pumped storage project in Marble Valley were abandoned.

After Marble Valley was abandoned, VEPCO screened their service area and the surrounding areas and selected seven sites for further study. Two of these sites, Poor Mountain and Bath County, were extensively investigated. Bath County was found to be the most suitable site due to its stable rock formations and two small creeks running through the valleys. The site was also attractive since it was sparsely inhabited. Although part of the land required by the project was in the George Washington National Forest, VEPCO did not anticipate serious opposition to land acquisition because the area is not a suitable recreational area.

4.5.2 Project Planning and Licensing

During the planning stages for the Bath County project, VEPCO experienced significant load growth. With their build-up of nuclear and coal-fired units, and the availability of excess baseload power, pumped storage was the most economic peaking technology available. VEPCO designed the Bath County project to be the largest size possible, 2100 MW. VEPCO intended to be the sole owner and operator. The long lead time anticipated for licensing and construction would allow VEPCO to develop the Bath County site and to pace its development with the development of base load plants.

The FPC preliminary permit for Bath County was issued to VEPCO in February, 1972. After completing detailed exploratory investigations and plant design plans, the construction license application was filed in July, 1973. The regulatory climate had changed drastically since 1969, when the Ludington Pumped Storage Plant was licensed. Environmental approvals were more rigorous and projects could easily be delayed in the licensing process. VEPCO encountered opposition from the citizen action groups, environmental preservation organizations and numerous independent citizens. Commission hearings for the project began in late 1975 and continued through 1976. In September 1976, an initial decision on the license was issued and after internal review and modifications, the FPC license to construct and operate the plant was granted in January, 1977.

4.5.3 Project Delays

Construction on the Bath County Project began in March 1977. As construction continued in the late 1970's, several drastic problems surfaced, that VEPCO and FERC did not anticipate. VEPCO's original projections of a 10.6 percent load growth in the 1980's plummeted. The current projected load growth rate is about 2 percent. Consequently, VEPCO delayed new starts on a number of nuclear plants. The costs of VEPCO's expansion program was escalating at a faster rate than anticipated. With the adjusted load growth and the schedule delays, VEPCO could not utilize the full capacity of the Bath County project until at least 1995. VEPCO slowed project construction in late 1979 and considered a number of possible arrangements to ease their financial difficulties.

4.5.4 Selecting a Partner

VEPCO considered a long term electricity sales agreement with a neighboring utility. Neighboring utilities, however, were also experiencing a decrease in load growth at the time. For these reasons, VEPCO was unable to negotiate a long term electricity sales arrangement and was compelled to find a partner for the Bath County project. VEPCO screened utilities in all neighboring service areas in search of a partner for the plant.

The Potomac Electric Power Company and Baltimore Gas and Electric expressed interest in the storage project, but neither utility anticipated a demand for peaking power until the next decade. Two utility holding companies were identified who were interested in sharing the storage project, American Electric Power (AEP) and Allegheny Power System (APS). Both utilities are near to VEPCO service areas, are heavily interconnected, and have a history of good working relationships with VEPCO.

American Electric Power was interested in the Bath County project since they had excess baseload power and a need for peaking capacity. AEP had recently launched an aggressive expansion program and was involved in a great deal of construction and improvement in their system. Although cancellation of the proposed Blue Ridge Pumped Storage Plant increased AEP's interest in the project, AEP did not have the necessary funds to commit to the Bath project. Since VEPCO's reasons for partnership were primarily for financial relief, Allegheny Power System, Inc. seemed the more attractive partner.

4.5.5 Background on Allegheny Power System (APS)

APS is a utility holding company system composed of three subsidiary companies, Monongahela Power Company, The Potomac Edison Company and West Penn Power Company. Service areas include parts of Virginia, West Virginia, Ohio, Pennsylvania and Maryland. The system is physically interconnected and operates as a single integrated electric utility system. VEPCO and APS service areas are adjacent and their power systems are well connected by high voltage transmission lines. For the past few years, VEPCO and APS have used a diversity exchange agreement to meet peak seasonal demands by interchanging 300 MW of power in the summer and winter. This agreement will expire in 1986.

Located in the midst of the coal region in a heavily industrialized area, coal-fueled generation plants account for 93 percent of Allegheny's total power capacity. Because electricity produced from coal is substantially less than the cost of oil generated power, APS can easily sell all of its surplus electricity at any time of the day to oil-powered eastern utilities. Allegheny has a high baseload capacity and recently brought two new coal generators on line. With these additional baseload units, APS will have enough power to pump its share of the Bath County plant.

Thus, APS expects to become a partner for the Bath County project with VEPCO. Not only did APS have baseload power, a need for capacity in the mid 1980s, a growing peak demand, and a strong interest in storage technology, they had the financial resources needed.

4.5.6 Joint Agreement

Negotiations between APS and Vepco began in the spring of 1980. Because of the high cost of capital, the agreement was delayed until later in the year. The agreement for the Bath County project was announced in June, 1981. With the possibility that APS may proceed with Davis, APS agreed to buy 20 percent of the project and to purchase capacity of another 20 percent of the plant for at least 10 years. According to the agreement, APS has the option to increase this share to 50 percent. With Allegheny's investment, the first three units at the plant are scheduled to come on line in late 1985 and the final three units will begin operation in 1986.

The cost of this sale has been estimated by VEPCO officials at \$285 million dollars. The final project cost may be as high as \$1.7 billion dollars.

Joint responsibility for project cost and operational requirements will allow the project to be effectively utilized as soon as construction is completed. VEPCO's pumping requirements will be consistent with their surplus baseload capacity and their diminished load growth.

4.5.7 Plant Licensing

VEPCO and APS must obtain approvals from FERC, the SEC, and five state agencies.

Joint license applications have been filed in five states where APS subsidiaries and VEPCO have service areas, and individually in states where only one utility operates. Obtaining state approvals can be time consuming since states differ on filing procedures. The APS companies must also receive Securities and Exchange Commission approvals after FERC and the state's approval.

At this time, four out of five states have approved the project.

4.5.8 Operating Agreement

VEPCO will operate the Bath County plant. The joint agreement specifies that APS will pay for its share of the operating and maintenance charges each year. A joint operating committee will oversee plant operations and provide management guidance.

4.5.9 Issues Affecting the Project

4.5.9.1 Load Matching. Discussions with utility officials involved in the Bath County project revealed two distinct schools of thought on this issue. VEPCO representatives believe that almost any utility can share a storage project. Adjacent systems with similar load profiles make good partners since they can usually coordinate their pumping/generation schedules. VEPCO also considered working with a utility in a different time zone and they did not foresee any serious problems with this type of arrangement. APS believes that there are necessary criteria for sharing a project. Seasonal diversity in peaking and similar daily load profiles are judged to be advantageous. While VEPCO's opinion that almost any utility can share a storage project is informal, this is the prevalent view among utilities. APS, however, believes a more formal evaluation is necessary to match utilities for a joint project.

Before a final agreement was completed, VEPCO and APS carefully analyzed their load profiles in order to assess the operational requirements of the plant. Each utility identified the week in which the energy demand was the greatest in its history. Demand was superimposed and analysis showed that the joint peaking demand could be satisfied. A thorough analysis of the system needs and peak demand periods demonstrated that regardless of the similarity of system load profiles, APS and VEPCO could jointly use the Bath County plant.

One benefit associated with neighboring utility companies as project partners is the use of existing interconnection systems to facilitate electricity purchase agreements. VEPCO and APS are very efficiently interconnected by high voltage lines. Although the costs of building new transmission

lines to connect one utility to a project outside its service area are minor relative to the costs of plant construction, difficulties in gaining rights-of-way for new transmission facilities is a potential barrier to joint projects. For the Bath Project, no additional transmission lines were needed to connect APS with Bath. Two major lines will connect Bath to the Lexington and Valley transmission stations. APS interconnects with VEPCO in the Valley area.

In summary, although there may be benefits gained by matching utilities with seasonal diversity and daily load similarity, this criterion is not mandatory for a joint storage agreement.

4.5.9.2 Joint Projects and Public Sector Utilities. Generally, public sector utilities seldom have amounts of surplus energy necessary to charge a storage system. While they may sell their excess power to a utility and indirectly benefit from a storage plant, it is unlikely that they could be a partner in a joint project. VEPCO anticipates that the Bath County Pumped Storage Project will be beneficial to small local utilities as well as to the larger utilities that are interconnected with VEPCO because Bath will provide lower-cost energy to the system during peak periods and for emergency needs.

4.5.9.3 Joint Ventures, Financing, and Precedent Agreements. When a joint venture was first proposed for Bath County, VEPCO studied previous joint storage agreements for information and guidance. These prior agreements had been written before a project was licensed. The issues of concern to VEPCO were never encountered by the owners of the Ludington or Kinzua plants. Unlike these two projects, Bath originally began as an independent project. VEPCO assumed all of the risks for the project and conducted the studies required by regulatory agencies. Time consuming negotiations were required to achieve equitable division of costs, risks and responsibilities.

A trust was formed in 1980 to finance construction of the Bath County Pumped Storage Project. The Bath County Hydroelectric Trust was devised to finance Bath construction at lower interest rates than VEPCO itself could secure. The trust uses the value of the Bath County Project property to secure its finances. Both practical and flexible, the Trust is an effective financing method by which VEPCO can complete the Bath County Pumped Storage Project. After construction is completed, the Trust will be terminated.

4.5.9.4 State and Federal Regulatory Issues. Before the license was issued to VEPCO in 1977, the Federal and State Commissions investigated the environmental oppositions to the project. The Commissions ruled that the creeks utilized by the project were not outstanding fishing streams. VEPCO is required to mitigate fishery damage and to improve the downstream fisheries. Like the projects discussed earlier, it is plausible that environmental issues may be raised after the project is operating. However, no opposition has surfaced in connection with FERC's notice of the application to transfer the license.

5.0 SUMMARY OF SURVEY FINDINGS

This section summarizes the issues found during the survey as being significant in affecting the joint establishment and operation of conventional pumped hydroelectric, energy storage projects. Pumped hydro is the only storage technology extensively used in the U.S. But, the findings summarized below are felt to be generally applicable to any joint, large-scale utility storage system. Since it is difficult to separate the issues of joint ownership from those of storage facilities in general, all issues are discussed. Also, the future of storage as perceived by the user (utility) community is discussed. It is important to remember that the issues are not necessarily mutually exclusive; therefore, a single fact about a project may carry implications for more than one issue.

5.1 Institutional Issues

Table 3 summarizes the institutional issues in abbreviated form. The institutional issues, broadly defined, are those which utility companies must consider as a procedural norm before entering into a joint agreement. The issues can stem from logistical concerns, business concerns, or from the general conservation concerns of the utility companies. The following issues were considered the most interesting by utility company representatives.

5.1.1 Number of Partners. What is the optimum number of partners for a jointly-owned storage project?

Yards Creek. Two partners, 50-50 split.

Seneca (Kinzua). Two partners. Political factors motivated quick development and negotiation for and with a partner. Chose 80/20 split, developer retaining only 20% due to expected availability of other planned storage, which in the end, did not pan out.

Ludington. Two partners plus leased interest of a third participant. 51/49 split. Third party was not desired for ownership in joint agreement. Leasing 1/3 capacity to third party was desirable until full capacity needed by major partners, who desired full plant ownership.

Bath County. Originally designed for single owner based on forecasted load/peak growth. Single owner had to find a partner to share development costs, provide pumping power, and use peak power available. Still under development. 60/40 split, including options.

The key determinant for the number of partners in a joint storage agreement is the physical size of the plant and its planned maximum MW output. All utilities felt that the most cost-effective, physical size of the storage facility is determined by the site. Once project size is determined, the minimum number of partners that can adequately use the capacity can be determined. Thus, two, or three as in the case of Ludington, partner

TABLE 3. INSTITUTIONAL ISSUES SUMMARY

Issue	Utility Response	Probable Impact
- What is the optimum number of partners for a jointly-owned storage project?	- Dependent on plant capacity; minimum number is preferred.	- Large plants will require joint ownership and/or capacity purchase agreements.
- Is perception of joint projects influenced by a desire to remain autonomous?	- Yes, utilities would prefer to control individual plants; but this is secondary consideration.	- Other factors have primary impact when considering joint ownership.
- Is a joint venture between private and public sector utilities possible?	- Yes, but public sector utilities generally do not have base load capacity to pump.	- Needs of public sector utilities will be served by power purchase agreements, not as co-owner of the storage plants.
- Will business relationships with non-participating utilities be affected by a joint agreement?	- Small non-participating utilities may be of some concern.	- Small utilities could cause delays or problems if they cannot realize immediate benefits of co-owned storage.
- Have precedent agreements been used for forging new joint agreements?	- Yes, prior agreements have been studied.	- New joint agreements will be an asset in setting up future agreements.

arrangements were found. But, even in Ludington, only two co-owners were encountered.

5.1.2 Autonomy. Is the perception of joint projects influenced by a desire to remain autonomous?

Ludington. Partners had cooperated previously, and desired autonomy in their service areas; mutually interconnected and supportive of each other. Wanted to maintain full, joint ownership; therefore, concluded capacity lease agreement with third party.

Bath County. Single, autonomous partner on the basis of financial necessity. Partner had the following characteristics:

- Need for peaking power,
- Availability of pumping power,
- Available money to invest, had financial backing and capital reserves,
- History of good relationship with VEPCO,
- Large service area, subsidiaries,
- Physically interconnected with VEPCO,
- Operates a single, integrated system,
- Strong interest in storage technology.

Autonomy is desirable, but is manifested through the number of partners, their ability to cooperate, and the percentage split in ownership which is the determinant of who is the single operator of the plant on behalf of the partners.

5.1.3 Private and Public Sector Agreements. Is a joint venture between private and public sector utilities possible?

Seneca (Kinzua). It was observed that a joint venture between a public utility and a municipal/cooperative may receive more favorable support from Federal or State agencies than a joint public utility project.

Ludington. Joint operation of Ludington, and central coordination of the system generation capabilities improved relationships between the private utilities and municipals and cooperatives. Helps municipals utilize off-peak baseload, a market for excess baseload, and provides lower-cost peak power. Municipals work closely with the major partners and use the plant through power purchase agreements, the preferred mode of operation.

Bath County. It was observed that a joint venture between a public utility and municipals may mitigate state licensing delays, since municipals and cooperatives are not as heavily regulated as a public utility. But, municipals and cooperatives very seldom have excess baseload power. They cannot generally be major partners since they can only own a small percentage of the plant. Municipals and cooperatives can sell excess baseload to a public utility, hence can benefit from storage. Bath County project is expected to be beneficial to both small, local utilities as well as larger, interconnected companies; to provide lower-cost peak/emergency power.

5.1.4 Non-Participating Utilities. Will business relationships with non-participating utilities be affected by a joint agreement?

Seneca (Kinzua). Opposition to development was received from a local cooperative who wanted the Federal Government to develop Kinzua, rather than a private utility. That opposition was supported by other Federal agencies, but was overruled by FPC.

Ludington. Joint operation of Ludington, and central coordination of system generators improved relations between the major utilities and municipals and cooperatives.

Bath County. Not likely.

5.1.5 Precedent Agreements. Have precedent agreements been used for forging new joint agreements?

Yards Creek. This joint agreement established precedents. Licensing and operational success set precedent to encourage future joint agreements.

Ludington. This is the largest storage project in the U.S. Jointly owned, it is a major engineering accomplishment; thus, setting a precedent in and of itself.

Bath County. Served as precedent setting project in terms of problems faced and actions taken to solve problems. Previous joint agreements were used for information and guidance. Bath has different characteristics than Ludington, for example. It was originally conceived as an independent project. Risk was assumed by a single utility. Preliminary studies and plans were done by a single utility.

The Bath County developers feel that previous agreement and successful working experiences are very helpful when utilities begin negotiating new agreements; they establish precedents for cooperative work.

5.2 Regulatory Issues

Table 4 displays the regulatory issues. Regulatory issues are those questions and associated situations which a storage plant developer must address from the outset of planning. Licensing and associated procedural and substantive matters may be the single, most obstructing hurdle in developing a joint-storage project. There seem to be potentially many licenses and approvals to be achieved depending on the nature of the developers, their customers, and the jurisdictions included in their respective service areas.

5.2.1 FERC Licensing. Has FERC licensing been affected by joint ownership, and vice-versa?

TABLE 4. REGULATORY ISSUES SUMMARY

Issue	Utility Response	Probable Impact
- Has FERC licensing been affected by joint ownership, and vice-versa?	- No.	- No impact.
- Is joint ownership treated differently by regulatory and licensing groups?	- No, financial stability of companies must be demonstrated.	- Additional state licensing may be required if partners do not service the same state.
- Are Security and Exchange Commission approvals (holding companies only) affected by joint ownership?	- No.	- No impact.
- Are interstate and intrastate agreements regulated differently due to joint ownership?	- Additional approvals needed by all affected states.	- No impact at the Federal level.
- How are costs and risks associated with acquiring licenses, permits, etc., to be allocated amongst partners of a joint agreement?	- Owner/operator is designated and other owners may be charged a fee for these services.	- More joint projects will be initiated, instead of occurring after process has begun.

Yards Creek. No environmental or regulatory opposition was encountered during licensing.

Seneca (Kinzua). Minor partner took lead in licensing process due to their initial role in planning the project. A joint application was submitted to FERC for licensing. FERC overruled opposition to project exhibited by other Federal agencies. Federal lands were used, and it was observed that the use of Federal lands, especially those screened for Federal projects, can facilitate licensing process. It was observed that FERC may challenge UPH on the basis of higher cost. Federal agencies license and establish rates, but are not involved in planning. It is the utility company's responsibility to coordinate planning, power purchases, and to coordinate joint agreements. Success of joint agreement at Kinzua due to integration of planning activities between partners, and secondarily to FERC, in licensing phase.

Ludington. Took 15 years to plan, license, and construct. Major partner took lead in licensing procedures with FERC. Both partners were financially stable; could finance construction with existing company assets and loans. Third partner not needed to help finance. Peak power needs of neighboring utilities was used to justify development of Ludington to maximum capacity. FERC license approved the leased power agreement. Lease was major factor in justifying development of Ludington to maximum capacity; it was in the customer's best interest for long-term economic savings. FERC allowed the overbuild of capacity since the excess could be used by neighbors.

FERC had jurisdiction over modifications to joint license for Ludington, including lease arrangement approvals. The present license was issued based on anticipated rate of load growth, which has diminished considerably due to recessionary climate. Both major partners have sizable reserves. Nonetheless, no unusual problems are anticipated in revising the licensing arrangement by FERC, or FERC approving a new lease agreement.

It was observed that some utilities fear that FERC will modify licenses, or reevaluate articles of license at renewal time, possibly arbitrarily, yielding unforeseen difficulties and costs. Other, recurring problems with regulatory approvals included increased emphasis on environment and conservation.

Bath County. More detailed and stringent licensing procedures and requirements, including NEPA approvals, are needed than on the other three projects. Times have changed. Burgeoning demand growth which existed and was projected to continue served as the basis for plant planning and preliminary licensing activities. Actual (reduced) growth, on the other hand, plus anticipated long lead time needed for licensing and constructing, may provide a longer term advantage in building Bath to maximum capacity.

Preliminary FERC license issued. Subsequently, after detailed preparatory investigations and plant design planning, construction application filed. Encountered environmental/citizens/preservation opposition. Took two years to approve construction license.

Most important is FERC approval of ownership transfer. Transfer of a pumped storage license is unprecedented for FERC. FERC approval expected for transfer of ownership because public's best interest will be served.

5.2.2 Treatment of Joint Ownership. Is joint ownership treated differently by regulatory and licensing groups?

Yards Creek. Fifty percent split approved for joint ownership and responsibility. State regulatory commission required that Yards Creek be treated independently from other projects in the Delaware River basin, and that further project development be carefully coordinated by co-owners with Yards Creek. Encountered no major problems.

Seneca (Kinzua). Joint ownership arrangement considered mutually satisfactory benefiting both partners and power pools.

Ludington. Coordination agreement required, to provide:

- Joint studies and planning,
- Priorities determination for expansion in both systems, including pumped storage, and
- High voltage grid connection between partners and with neighbors.

Joint agreement specified:

- Ownership share (51/49),
- Final licensing details,
- Division of capital costs (51/49), and
- Leasing arrangement for 15 years.

Bath County. Plant under construction with sale of part to second utility company pending. Planning and ownership arrangement, previously explained, considered unique. New partner agreed to buy 20% and purchase another 20% of capacity for 10 years; yielding 40% interest. Negotiations delayed by high cost of capital and diminished load growth. New partner has option of increasing share to 50%.

Both partners expect license to be successfully transferred. Although time consuming, an equitable division of costs, risks, and responsibilities was achieved.

5.2.3 SEC Approvals. Are Security and Exchange Commission (SEC) approvals (holding companies only) affected by joint ownership?

Seneca (Kinzua). Plant licensed by operating subsidiary of a large service area operator. Such an arrangement does not circumvent need for SEC approval. But, only State approvals are required in individual State serviced rather than by all States serviced by large power pool of which operators are members. Such an arrangement may ease licensing delays.

Bath County. SEC approvals needed for one partner, a holding company.

5.2.4 Interstate/Intrastate Regulations. Are interstate and intrastate agreements regulated differently due to joint ownership?

Yards Creek. Received regulatory approval for project with minimum delays. Coordination of projects in Delaware River basin stipulated as previously described. No Federal or State approval delays.

Seneca (Kinzua). See comments on SEC approvals. It was observed that State approvals can pose serious problems to project licensing. Partners pay an annual fee to the Federal Government for water, dam use, and Federal land use. Does not guarantee a cost savings.

Agreement with Army Corps of Engineers includes stipulations that:

- Allow efficient and safe operation of river projects,
- Water used for power can be discharged behind dam, or downstream depending on flow level,
- Provide for minimum discharge rates for flood control and recreation, and
- Require plant operator to maintain steady flow in downstream release.

It was observed that only States approve load management and customer-side technologies, and rates; therefore, implementation can be rapid and less costly. State and Federal agencies license and establish rates, but are not involved in planning. The responsibility of the utility company for planning includes: (1) coordination of power purchases, and (2) coordination of joint agreements.

Success of joint agreement at Seneca was due primarily to integration of planning activities between parties, and only secondarily to State/FERC activities, in the licensing phase.

Ludington. Unique nature of planning arrangements plus inclusion of leased interest of a participant affected approvals. The close, and open, relationship with State regulatory commission fostered more favorable rate treatment. Close working relationship included keeping the State informed of Federal sales/power purchase regulation activities, and informing the State of central coordination and control activities with neighbors.

Bath County. More detailed licensing procedures required, including NEPA approvals. Concurrent with FERC approval of license transfer, five state approvals were required. Four out of five have approved as of this time.

It was observed that obtaining State licensing approvals can be time consuming because:

- States differ on filing procedures, and
- Some States require rigorous investigation of alternatives.

Ideal situation would be a single joint hearing with participation by all States affected.

5.2.5 Costs and Risks. How are costs and risks associated with acquiring licenses, permits, etc., to be allocated amongst partners of a joint agreement?

Ludington. Development to maximum capacity was supported by anticipated cost savings in meeting anticipated demands, though full capacity could not initially be completely utilized. The capacity purchase lease arrangement has favorable cost aspects since the leasee pays operating and maintenance fees, transmission and transmission power loss costs, and supplies its own pumping power, reclaiming it during generation cycles.

Bath County. Essential change from single owner to partnership arrangement delayed construction, which increased construction costs. Issues initially not anticipated by either VEPCO, or the FERC, included:

- Reduced load growth projections,
- Costs escalating faster than anticipated,
- Financial problems evolving from existing baseload expansion program, and
- Inability to utilize full storage capacity until later than planned.

5.3 Technical Issues

Technical issues are displayed in Table 5. Technical issues deal with hardware technology, matters of compatibility, geographical relationships among partners, additional cost matters, comparisons of alternatives, and management and operational aspects of joint storage projects. All of these factors must be addressed in planning. Many are also addressed in the regulatory licensing process. Thus, it is sometimes difficult to separate the technical and operational aspects of a project from regulatory aspects. Nevertheless, technical considerations have a unique dimension affecting relationships among joint storage project partners.

5.3.1 Load Profile Match. Must load profiles (i.e., daily, seasonal, or annual peak demand fluctuation) match before entering into a jointly-owned storage agreement?

Seneca (Kinzua). The major partner had available baseload power to pump and needed peaking capacity, and its membership in a power pool also made inexpensive power to pump available. There was a timely occurrence in matching with the minor partner's interest in priority development of Kinzua before the opportunity to develop disappeared. Design of plant to maximum capacity possible for site carried future load-match implications. Both system needs were similar, yielding no operating problems.

In another vein, the load characteristics of all power pool members was used in justifying the project, even though only a single subsidiary was the developer.

Ludington. Peak power needs of neighboring utilities, as well as partners, supported need to develop Ludington to maximum capacity. From an operation viewpoint, no problems were encountered in scheduling since all three partners (two + lessee) had similar loads, and all were large enough to maintain a regular operating schedule.

Teaming to share a storage plant was not considered a major problem, especially for neighboring utilities. Significant diversity in load profiles among partners were not needed. But, similarity in overall system needs was required. Ludington accommodates demands of all three major participants.

Bath County. In the beginning, VEPCO's load growth factor indicated need for increased baseload as well as peak. Buildup of baseload nuclear and coal units ensured available baseload power to pump. Pumped storage considered the most economical. Thus, at the outset, VEPCO was not concerned with matching with a partner. That came later, and involved more than simple load matching as was described previously.

VEPCO had become a dual-season peaking utility, and their growing power needs made a previous diversity exchange agreement with partner not maintainable. Needed pumped storage.

TABLE 5. TECHNICAL ISSUES SUMMARY

Issue	Utility Response	Probable Impact
- Must load profiles (i.e., daily, seasonal, or annual peak demand fluctuation) match before entering into a jointly-owned storage agreement?	- Load profiles need not match if integration of transmission systems is substantial.	- Load discrepancies between utilities will not preclude a storage co-ownership agreement.
- Is proximity to load center a major factor when considering whether to become a partner in a large-scale storage facility?	- No, several plants are located away from load centers.	- Distant siting of project is not a major factor.
- Are transmission line costs, placement, or power losses significant factor on whether to build a storage facility?	- Placement is important; obtaining right-of-way for transmission lines could be difficult.	- Location of transmission lines is a consideration when planning joint agreements. This favors agreements among neighboring utilities with highly integrated transmission networks.
- Does storage work better in conjunction with a power pool or coordination group?	- Yes, coordinated pumping, generating and dispatch offers several benefits.	- Inter-powerpool arrangements and formation of new coordination centers could evolve.
- Who should operate the plant?	- Major user of plant should supervise operations and coordinate pumping and generation.	- Geographical location of plant may not necessarily determine operator.
- Are customer-side load management technologies and large-scale energy storage complementary?	- Yes, customer-wide management enhances overall system efficiency.	- Utilities will continue to pursue both options.

It was concluded that VEPCO had a choice of formal or informal matching with its partner. And, it was found that formal matching of seasonal diversity and load profiles was neither mandatory nor desired. Planning, joint planning, was the essential ingredient. This conclusion was reached after considering two opposing schools of thought. The first argues that almost any utility can share a storage project, that adjacent system with similar profiles make good partners, and that pumping/generation schedules could be coordinated even across time zones. The second was that seasonal diversity in peaking and similar load profiles are prerequisites. Analysis showed that regardless of the similarity of load profiles, a storage project could be jointly used.

5.3.2 Proximity. Is proximity to load center a major factor when considering whether to become a partner in a large-scale storage facility?

Yards Creek. This project demonstrated the advantage of incorporating a storage plant in a centrally-operated, geographically-separated generation, storage, and transmission system.

Seneca (Kinzua). Kinzua is located in the service area of the partner which is not responsible for operating/managing the storage project; an interstate venture. It has been observed that central storage is usually located away from the load center of the system. In joint projects even more decentralization may occur, at an even greater distance, possibly due to type of terrain required for storage projects.

Ludington. Storage plant located in one of the member's service area, along Lake Michigan, geographically separated from lessee.

Bath County. Partner, has interconnected service area, well connected with high-voltage transmission equipment.

5.3.3 Transmission Costs. Are transmission line costs, placement, or power losses significant factors on whether to build a storage facility?

Seneca (Kinzua). Project location was advantageous under Federal jurisdiction. But, building of transmission lines and acquisition of rights-of-way were required. Decentralization does incur costs of transmission facilities and transmission power loss.

It was observed that some believe the costs of transmission lines to interconnect a joint plant, or problems in securing rights-of-way, significantly escalated project costs. At Kinzua, the joint project required only as much new transmission facilities as an equivalent baseload plant.

Others feel that transmission line costs for joint projects are a minor problem, since utilities are already well interconnected. Existing transmission facilities and lines were used at Kinzua.

Ludington. Feasibility studies showed Ludington not economically competitive until the interconnection system was improved. It was also observed that a large-capacity, pumped storage plant requires an integrated transmission system for efficient and economical pumping and distribution of generated power. At Ludington, a centralized coordination center (not a power pool) was established to operate a fully interconnected system. Control of dispatching and operation of the entire generating capacity of the two partners maintained by the center, fully integrating Ludington into the overall system.

Bath County. Physical interconnection with VEPCO, a single integrated system, and having a well connected system with high voltage transmission lines were prerequisites for a partner, as was previously described. Such an interconnection advantage existed.

5.3.4 Power Pools. Does storage work better in conjunction with a power pool or coordination group?

Seneca (Kinzua). Minor partner was member of a power pool. It and the power pool preferred to develop Kinzua rather than lose the opportunity. Major partner was also a member of a power pool, and needed peaking power. In fact, the whole power pool could use Kinzua peaking power. Major partner's membership in a power pool provided inexpensive power to pump Kinzua. Joint ownership arrangement proved mutually satisfactory, benefiting partners and power pools alike.

It was observed that pumped storage is best utilized when tied to a power pool. The joint planning and operation of such capital-intensive projects reduces costs, risks, and increases benefits. Power pool membership is also advantageous during licensing; total pool load/capacity can be used for justification. On the other hand, scheduling conflicts are probable within a power pool; e.g., matching excess power or reserve capacity of one member, with another member's storage plans, when other uses for the excess power had already been planned.

Ludington. Centralized control center, not a power pool, operated the system.

5.3.5 Operational Responsibility. Who should operate the plant?

Yards Creek. Operating responsibility was defined by plant location in operator's service area. No management, operational, or integration problems were encountered. There exists a good working relationship between partners. Expedient negotiations, and operations according to agreement highlight system and plant functioning.

Seneca (Kinzua). Major owner (80%) responsible for dispatching and operation. Plant licensed by an operating subsidiary of a large service area operator. Major partner establishes and coordinates pumping and generation schedule with minor partner on a day ahead-of-time basis. Both partners needs are similar yielding no operating problems.

Minor partner claims a small share of generation output and is small in capacity in comparison with the total system. That means that if generated power is not need by the minor partner, it can still be used.

The 80/20 split allows flexible and uncomplicated operations. A different (50/50) ownership split might pose more operational scheduling problems. Central station storage and dispersed storage methods are necessary for efficient and cost-effective management of system loads. A central switchyard monitors power and accounts for partners' shares for pumping and generation.

Ludington. The joint agreement specified a 51/49 percent ownership share split for the purpose of reconciliation of deadlocked management issues. This arrangement has proven satisfactory for all participants. No scheduling problems have been encountered, due at least in part, to similarities in load profile and their respective large sizes. Central scheduling is provided for pumping and generation. Lessee coordinates needs with the schedule. Schedule for week is published allowing minor adjustments one day prior to operating pump/generate periods.

If lessee wants to pump, and pumping is not scheduled, capacity credits or water volume credits are granted, and the excess electricity is used elsewhere. As a rule, the lessee provides some pumping power during each pump cycle. If pumping is needed and the principal partners do not have sufficient excess power, all three pump together.

Bath County. Partnership arrangement and operating responsibility are crucial. Major partner maintains 80% of ownership and 60% of capacity interest. Minor partner pays share of annual operations, maintenance, and buys 20% of generated capacity, as previously described. Prime monitors power for the project, and is responsible for scheduling, operations, and financial management. A joint operating committee oversees operations and provides management guidance.

5.3.6 Customer-side Technologies. Are customer-side load management technologies and large-scale energy storage complementary?

Yards Creek. No indication.

Seneca (Kinzua). It was observed that dispersed storage and customer-side load management methods benefit consumer costs, and help management of peak loads. Large-scale storage and customer-side load management enjoy a synergistic relationship, providing best flexibility in managing fluctuating loads. These partners encourage load management and customer participation.

Ludington. It was concluded that customer-side load management technologies provide increased benefits in a central station storage system. Major partners experimented with various load management techniques. They intend to expand plans for further experimentation and use in future. One partner seemed more confident than the other in the efficacy such techniques.

Time-of-day pricing and radio controlled water heating have been attempted. They also have been involved in Government studies of wind turbines and solar energy uses.

Experimentation has also included thermal heat storage in bricks and water heating control technologies. Installation difficulties were experienced, and rate change needs disillusioned one partner. But, partners plan to use load management as a peak-leveling method and want to expand experimental programs.

Bath County. This group is of the opinion that load management techniques increase the efficiency of large-scale storage projects. Customer side load management methods addressed were thermal storage and automatic, signal-controlled water heating. Principal partner (VEPCO) is attempting to implement these, to best economic benefits for the future.

5.4 Environmental Issues

Table 6 displays the environmental issues. Environmental issues relating to conservation and preservation of terrain, habitat, and fish and wildlife as well as ecological and aesthetic considerations have burdened the process of joint project licensing and development in recent years. That burden results in time loss and increased costs, both in litigation or licensing procedures, and in construction and subsequent operation. Comparing Bath County with Yards Creek, involving significantly different dates of construction, provides a marked contrast in licensing and approval situations and sharply contrasting kinds and levels of justification activities for the projects. At the same time, issues have little or nothing to do with whether a project is jointly owned.

5.4.1 Plant Siting. Are siting problems significant for pumped storage projects?

Yards Creek. No environmental opposition encountered during licensing.

Seneca (Kinzua). This project involved private development of public lands; project location was advantageous since private lands did not have to be acquired. Dam had already been built, avoiding environmental opposition to be expected if dam had not already been built, thus facilitating licensing. Environmental problems are considered a major barrier in licensing any storage unit.

Ludington. Soil conditions and proximity to lake ports were principal drivers of site choice. Studies denied that Ludington adversely affected shoreline/bluff erosion, contrary to allegations by local coalition to prevent shoreline erosion. Ludington partners felt that environmental problems can be a major barrier to joint project development and operation; a continuing problem that exists even after plant commissioning.

TABLE 6. ENVIRONMENTAL ISSUES SUMMARY

Issue	Utility Response	Probable Impact
- Are siting problems significant for pumped storage projects?	- Yes, depending on geographic region or territory.*	- Increased potential for second generation technologies.
- Have the following issues been significant obstacles to the construction of storage plants?		
- aesthetic destruction of land	- Yes, in some instances	- has had considerable impact in cancelling or delaying projects.
- recreational limitation	- No	- no major impact; solutions can usually be negotiated with local authorities.
- fish and wildlife restoration	- Yes	- major issues still need to be addressed; issues are site specific
- proliferation of nuclear power plants?	- Yes	- none, realization that this argument is fallacious will lessen its impact.

* Applies to pumped storage in general; joint ownership is a secondary consideration if it is a factor at all.

Bath County. The first site chosen was geologically unsuitable. Seven more sites were surveyed, yielding the Bath County site as the choice. Bath County provided advantageous geological characteristics, creek water availability and sparseness of population - a remote site. The land area was not amenable to recreational activities, and some land on site was owned by the Federal Government. It has been VEPCO's experience that environmental issues relating to plant siting are significant to FERC licensing.

5.4.2 Significant Environmental Obstacles. Have the following issues been significant obstacles to the construction of storage plants: (1) aesthetic destruction of land, (2) recreational limitations, (3) fish and wildlife restoration, (4) proliferation of nuclear energy plants?

Yards Creek. No environmental protests were allowed by regulatory agencies.

Seneca (Kinzua). Environmental constraints lengthen pumped storage licensing and construction periods; a major barrier. Fish and wildlife restoration is a controversial issue during construction and operation. There is continuing opposition on behalf of fish and wildlife at Kinzua. Such environmental problems are considered threats to new pumped storage or conventional hydroelectric projects. Army Corps of Engineers maintains the recreational and fishing areas, and conducts environmental studies, with financial assistance from the utility companies.

Ludington. Recurring problems have been encountered with regulatory approvals such as:

- FERC requirements vis-a-vis environment,
- Mitigation of damage to fish and wildlife,
- absence of guidance on how to best develop and maintain fish populations nearby, and
- Active opposition from a local coalition to prevent shoreline erosion.

Aesthetic problems can be a major barrier to joint storage project development and operation.

Bath County. Land area is not amenable to recreation, but VEPCO encountered environmental approval requirements including some opposition from citizens and preservationist organizations. Developer required to mitigate any damage, and improve fisheries downstream.

5.5 Economic Issues

The economic factors, as displayed in Table 7, covered under the survey were rate base factors, insurance and liability, and cost of capital. It is clear that economic considerations motivate the undertaking of a joint storage project. Therefore, it is not unreasonable to say that all issues covered in the survey had economic implications.

TABLE 7. ECONOMIC ISSUES SUMMARY

Issue	Utility Response	Probable Impact
- Does joint ownership have significant impact on the rate base of member utilities?	- Yes, definitely.	- This important factor is critical when deciding whether to own, lease or simply purchase power.
- Are insurance and liability issues of significant concern in joint ownership of storage facilities?	- Yes, financial stability is critical to obtaining federal licensing.	- Utilities will want to "guarantee" their investment; will screen potential co-owners for financial well being.
- Has cost or availability of capital affected joint ownership?	- Yes, may be able to develop "creative financing" alternatives.	- Should benefit the growth of joint ownership.

5.5.1 Rate Base. Does joint ownership have significant impact on the rate base of member utilities?

Seneca (Kinzua). At this plant, pumped storage provides power at lower cost than oil or gas turbine generators, even though pumping costs have recently increased.

Ludington. To date, the plant has realized significantly increased operational efficiency and cost savings which have been passed on to consumers. For example, a capacity purchase agreement was negotiated with a third party. It was observed that the inclusion of pumped storage in a central control arrangement is most efficient. Efficiency is realized since inexpensive power from baseload generators, plus power purchases, can be used for pumping. Thus, peak power can be supplied at cost-competitive rates. Inexpensive off-peak power is converted into low-cost peak power. In addition, the rate base for each utility includes Ludington according to the 51/49 percent ownership split.

It was observed that State regulatory commission treats the capacity purchase agreement as a purchased power transaction and not as a temporary sale of plant capacity. Hence, purchase revenues from the lessee are included in each partners' revenues for tax purposes according to the 51/49 percent ownership split.

Bath County. Pumped storage hydropower is recognized as the most economical means of meeting peak demands. Whether to lease or sell a portion of a plant can have a rate base impact since leases are considered as power purchase agreements while plant ownership is considered in rate base.

5.5.2 Insurance and Liability. Are insurance and liability issues of significant concern in joint ownership of storage facilities?

No indication was found that these factors are of a major concern. Formation of independent subsidiaries can moderate liability.

5.5.3 Cost of Capital. Has the cost or availability of capital affected joint ownership?

Seneca (Kinzua). It was observed that economic benefits are always the decisive factor influencing type of peaking technology chosen - the primary consideration.

Ludington. From the outset, both partners were financially stable and could finance construction with company assets and loans. They did not need a third partner to assist in financing. Capital cost was therefore not a factor.

Bath County. This project encountered escalation of costs at a faster rate than anticipated. This, among other factors, resulted in a slowed

construction schedule and concomitant search for new financial arrangements. A trust was formed to obtain, inter alia, lower interest rates on secured financing.

5.6 Special Issues

The special issues are presented in Table 8. These special issues cover second generation technologies, regulatory reforms and organizational actions possible which foster (or force) joint projects. Utilities tend to consider organizational fostering as forcing by some governmental agency.

5.6.1 Second Generation Technologies. Do second generation storage concepts (CAES, SMES, UPH) have advantages over pumped storage?

Seneca (Kinzua). UPH is not considered more economical than CPH. A planned UPH project was cancelled when a mine owner revoked a property lease. UPH is considered to have the advantage that storage can be located near major load centers, with minimal environmental intrusion. But, in general, economic advantages favor conventional methods over advanced technologies.

5.6.2 Fostering Joint Projects. Should some organization take an active role in fostering (or forcing) joint projects?

Seneca (Kinzua). This project used an existing dam constructed by the Army Corps of Engineers - an existing technology. The dam was constructed anticipating a future need for hydro-power. The Corps forfeited interest in developing Kinzua. The dam had been built in an area traditionally opposed to Federal power projects. These folks feel that public utilities must assume responsibility for encouraging joint projects.

5.6.3 Regulatory Reforms. What regulatory reforms can be recommended to encourage storage projects?

This issue is discussed to some depth in the following section of this report.

TABLE 8. SPECIAL ISSUES SUMMARY

Issue	Utility Response	Probable Impact
<ul style="list-style-type: none"> - Do second generation storage concepts (CAES, SMES, UPH) have advantages over pumped storage? - Should some organization take an active role to foster (or encourage) joint projects? 	<ul style="list-style-type: none"> - Yes, these technologies may not need FERC licensing; also may have less environmental objection. - No, forced arrangements rarely work. 	<ul style="list-style-type: none"> - May spur interest in second generation technologies. - Current arrangements with neighboring utilities is adequate to facilitate joint agreements, utility organizations could play a key role (i.e., American Public Power, EPRI, Edison Electric Institute).
<ul style="list-style-type: none"> - What regulatory reforms can be recommended to encourage storage projects? 	<ul style="list-style-type: none"> - Major reforms should be Fuel Use Act, EPA regulations on coal plants, rate base regulations. 	<ul style="list-style-type: none"> - Changes in utility regulations are likely.

6.0 ADDITIONAL CONCLUSIONS AND OBSERVATIONS

The following conclusions and observations were gathered from sources other than the utility companies surveyed. Some came to light after a search of relevant literature. Others surfaced in discussions with individuals having a technical, business, or regulatory interest in energy storage. It is felt that by including these additional factors in this report, to broaden the array of issues and factors having direct or indirect influence on energy storage projects, provides the reader with a complete picture.

6.1 Factors Affecting Growth of Storage

The decisions for the utility planner in trying to predict the needs of his region as much as 15 years are difficult. Historically, the decision on which type of generation equipment should be added to a system was based on the "present worth of all future revenue requirements (pwafr)." This criterion includes calculation of the required number of hours per year of operation, the fuel used and its cost, probable operational availability, and the probable demand for electric power. Using these anticipated operating costs and average fixed cost, the present worth of all future revenue requirements are calculated for each new generation option. The results of the "pwafr" calculation tell the utility planner whether his system is in need of baseload capacity, intermediate (or cycling) capacity, or peak power generation equipment.

Baseload equipment is characterized by high capital costs and low operating costs. Figure 7 shows that, typically, the average total costs of operating baseload units more than 2800 hours per year is less than for other types of generation equipment. Intermediate generation equipment, needed to meet power demand that typically exists for 5-10 hours per day, is characterized by moderately high capital and operating costs. Total cost of electricity for these units operating between 1200 and 2800 hours annually is less than from other types of generation equipment. Peak power equipment has very low capital costs and high operating costs. This type of equipment can only be used optimally at less than about 1200 hours per year.

Construction of a large central station storage plant offers unique and difficult problems to utility planners. Storage systems (such as conventional pumped hydroelectric, compressed air, or underground pumped hydroelectric) are "fueled" with electric power from baseload generators and offer the additional benefits previously described. But, the use of storage facilities significantly changes the number of hours per year that baseload generators operate. These two unique operating and system characteristics tend to distort the choice of which generation system will deliver the needed power at lowest cost.

The results of "pwafr" calculations are only as good as the input information. The calculations themselves cannot take into account unexpected changes in fuel price, changes in regulatory policy, major economic problems within the utility, or other factors which affect power demand. Such factors

TYPICAL SCREENING CURVE FOR UTILITY SYSTEM

Figure 7

which have hindered the decision to build large storage projects over the past decade are load growth, capital availability, and regulatory influences.

6.1.1 Load Growth.

Figure 8 show historical trends for peak load and total electric demand. Peak load, the maximum demand for power, is the primary factor to be considered when deciding whether new generation or storage is needed on a utility system. The inability to accurately forecast peak load growth in the long term is a result of numerous unpredictable forces. For example, in the period from 1960 through 1973, the average peak load growth rate was 7.6 percent per year. This varied from a high in 1967 of 11.5 percent, to a low in 1966 of 5.0 percent. It was this level of average load growth, expected to continue through the year 2000, that utility planners used in determining future generation and storage needs.

In 1973, the United States suffered the oil embargo and the price of oil skyrocketed. The subsequent rise in electricity costs resulted in the initiation of institutional and regulatory programs aimed toward the conservation of energy. These programs, coupled with other economic factors, caused a decrease in the average rate of growth of peak loads which continues to the present. Load growth for the period 1973-1979 averaged only 3.1 percent. This drop in average load growth reduced the need for intermediate and peak power generation equipment, thus reducing the need for large-scale storage systems. Thus, utility planners were reluctant to recommend construction of large-scale storage plants.

6.1.2 Capital Availability

The availability of capital for building large, capital intensive facilities diminished in the past several years. During the 1950's and early 1960's the electric utility industry was a preferred customer of the investment community. The common stocks of utility companies sold at relatively high price/earnings ratios and there were plenty of buyers for preferred stocks and debt instruments. As the costs of utility operation increased and state regulatory agencies restricted rate increases, the industry lost its preferred investment status.

Figure 9 shows cost of capital and return on investment trends for the utility industry. The increase in the prime interest rate has outpaced the rate of return allowed by state regulatory agencies. Less capital intensive solutions to meeting peak power generation demands undermined significant growth of large-scale storage projects.

6.1.3 Regulatory Influences.

Of the many influences on which power generation equipment to build, the regulatory environment may have the most far reaching and decisive impact.

PEAK LOAD AND TOTAL ELECTRIC DEMAND HISTORICAL GROWTH

Figure 8

COST OF CAPITAL VS. RATE OF RETURN ON INVESTMENT FOR ELECTRIC UTILITIES

Figure 9

In particular, regulatory issues dealing with environmental objections or regulations have had a tremendous effect on the number of large-scale storage plants built. Economic regulatory activities have also hindered the building of storage facilities. State regulatory agencies provide constraints and/or catalysts to the investment planning that occurs in utilities. These agencies control the allowable rate of return and the composition of the base on which the rate is calculated. After the oil embargo of 1973, fuel adjustment clauses were implemented to cover the cost of fuel, but rate of return increases were not allowed to keep up with the cost of scarce capital. This contradictory situation created a bias against plant investments in storage systems even though storage systems are intended to help reduce fuel costs.

The complexity of the regulatory system led a number of utilities to develop financial models to estimate the impact that various regulatory alternatives might have on the utility's financial performance. There appears to be no conscious attempt to bring fuel clause effects into investment decisions.

6.2 Advantages of Jointly-Owned Storage

Figure 10 shows the growth in jointly-owned generation capacity. In the period from 1960 through 1980, thirty conventional pumped hydroelectric storage plants were built with total capacity of 13,000 MW (see Table 2 previously introduced). This includes plants that would have been planned before the 1973 oil embargo (allowing seven years lead time for planning). Expected additional capacity for new pumped storage plants for 1981 through 1986 is 3,500 MW with only five plants scheduled to be constructed.

Building a plant with another utility, holding company, or power pool (as opposed to a single developer) offers several advantages beyond the benefits of large-scale storage. Combining forces to build a joint storage project can maximize its capacity utilization. Since storage plants enjoy large economies of scale, combining the load needs of two or more utilities can approach the capacity of the storage plant. For example, two utilities with a 500 MW intermediate and peak power need could combine to build a 1000 MW pumped storage plant. Neither of them would have built the plant on their own since the optimum capacity of the plant would be in excess of their needs. The partnership allows utilities to jointly build a storage plant and jointly realize its associated benefits rather than each separately deciding on another intermediate and peak power option.

The second major advantage to joint ownership is the reduced capital cost needed by each participating utility. By participating in a jointly owned project the capital expenditures needed by a utility will be reduced to its percentage of ownership. Also, with the assets of more than one utility backing the project, a more attractive interest rate might be available.

Partnerships may even have an effect in overcoming some regulatory issues. In teaming together, utility companies can amplify their message to state regulatory commissions or Federal regulatory agencies. Strength in numbers has always been an advantage and regulatory groups seem to look favorably on joint ventures, when they are in the best interest of the public.

JOINTLY-OWNED UTILITY POWER GENERATION CAPACITY GROWTH

Figure 10

6.3 Future for Energy Storage

Utility companies have delayed or cancelled plans on major new construction facilities in the recent past and will continue to choose least capital-intensive solutions to their intermediate and peak power needs. But, despite the slowdown in demand growth, utilities will still need additional capacity in the out years (1990-2010). The future use of energy storage can be expected to remain an attractive and viable option, because of the long-term advantages of its use. Thus, there exists a potentially large market for energy storage, but only if reliability, technology, and favorable economics can be demonstrated. Assuming petroleum prices continue to rise, the use of oil-fired turbines as peak power generation units will probably diminish. Gas-fired turbines should have comparatively inexpensive fuel available in the future but their reliability is questioned by several utilities. The major competitors to large-scale storage will be cycling coal plants, and the use of batteries for storage at distributed (substation) sites. The decision on which option to pursue is system specific and must be evaluated on a case by case basis, comparing costs with benefits.

Development of large-scale utility storage projects is also detrimentally affected by the combined regulatory climate and public opinion. The regulatory climate and public opinion seem to be interdependent in that the latter directly influences the former. The public is generally against any form of reservoir construction usually on the basis of aesthetics or environmental issues; e.g., scenic beauty or wildlife survival. The cancellation of the Cornwall and Blue Ridge projects, because of such combined influences has discouraged the development of other storage facilities. In addition, the misconception that emphasizing large-scale storage potential is a ploy to improve the economic viability of nuclear power has also tarnished its image in the public's mind. Adverse public opinion, if it persists, causing significant delays in regulatory proceedings and licensing and stimulating increased regulatory controls over utilities, will have a negative influence on the construction of storage plants. Perhaps, in the future, the use of joint agreements and the successful and environmentally sound demonstration of second generation storage technology may make significant contributions in overcoming the regulatory and popular barriers to construction and operation of storage facilities.

6.3.1 Role of Joint Ownership

It has been well established that joint ownership of a large-scale storage facility has one major advantage over sole ownership; namely, the reduced capital outlays needed by each partner utility for constructing the plant. The option of leasing, instead of purchasing, ownership in the plant is also attractive to some utilities for financial reasons or to those who would not want a storage facility included in their rate base. By leasing the plant, or plant capacity, the agreement is treated as a power purchase arrangement rather than ownership of the plant. Other financing arrangements can also be set up by partners in the joint venture to reduce risks to the investors and to try to secure more attractive interest rates.

Secondary benefits can also be realized by joint owners through good business relationships with their partner utilities. During emergency situations the availability of power from the storage system might assist one of the partners with cooperation from the others. Secondly, coordination centers, similar to the one set up by Consumers Power and Detroit Edison, could result from new joint agreements. Major power pool members would probably not consider this sort of arrangement, but large independent utilities might. Coordination centers can markedly increase efficiency, flexibility, and emergency preparedness.

Complications arising from joint ownership seem to be minimal. Matching load profiles of partner utilities is not a significant problem if the utilities are sufficiently interconnected. Distance from the storage facility is not important because transmission line cost is minimal and power losses are not significant. Licensing problems are not more time consuming for several owners than they are for one owner. Additional state licenses may be required if partners service more than one state. Utilities would encourage the states to hold joint hearings.

On balance, the advantages for joint ownership outweigh the disadvantages. The major drawback is that some utilities perceive joint ownership as a loss of control and want to preserve their autonomy. This barrier seems to be breaking down and the trend toward joint ownership should continue.

6.3.2 Future for Second Generation Technologies

Second generation, large-scale storage technologies, include Compressed Air Energy Storage (CAES), Underground Pumped Hydroelectric Storage (UPH), and Superconducting Magnetic Energy Storage (SMES). SMES is not considered to be possible prior to the turn of the century; therefore, we will focus our discussion on UPH and CAES.

Underground Pumped Hydroelectric Storage. UPH is considered to have potential as a near-term storage technology. But, its marketability is constrained by two factors: site specificity and high costs. UPH is a modification of conventional pumped storage. Licensing procedures, economies of scale, site specificity requirements, and environmental problems would all be essentially the same for UPH as for conventional pumped hydro. High excavation costs also tend to make UPH more expensive than conventional pumped storage, unless a specific site (such as an abandoned cave or mine) is available for potential application.

Compressed Air Energy Storage. CAES offers more potential as a near-term storage technology. At present, the major benefit of CAES is that no federal licensing is required. The Federal Energy Regulatory Commission has jurisdiction in regulating the utilization of water resources on navigable bodies of water, to regulate the transmission and sale in interstate commerce of wholesale power, and to regulate projects on federal lands. Since CAES facilities would not be constructed on federal lands or using navigable waters, it does not appear likely that federal licensing would be required, unless statutory changes are made which include CAES.

An interesting precedent has recently been issued by FERC on the Seboyeta Pumped Storage Project in New Mexico. It was proposed that Public Service of New Mexico build a conventional pumped storage project located entirely on private lands about 45 miles west of Albuquerque. The lower reservoir of the project would use an arroyo or drywash (a channel which carries snowmelt or runoff but does not contain a normal flow) and a man-made upper reservoir. The water supply would be obtained by pumping groundwater from a mine ten miles away. FERC determined that since this project did not use a navigable body of water, it did not require licensing under the Federal Power Act. Similar decisions might be expected for CAES plants.

Exemption from federal licensing could mean that time delay for licensing of a storage project might be reduced by several years. That time delay has been the critical item in the past. Reducing the delay could allow utilities a more economical option for developing enhanced intermediate and peak power generation capacity.

Compressed Air Energy Storage also has secondary advantages over other large-scale energy storage technologies. These may play a more predominant role in light of the fact that no federal licensing is necessary. The fact that a CAES plant is smaller and can be built in modular units provides significant flexibility to the utility planner. A system as small as 200 MW or as large as 1000 MW could be incrementally built according to the changing needs of one or more utility companies. The fact that there is no federal licensing might also eliminate the primary forum where aesthetic and environmental objections are voiced. Finally, there are many more "suitable" sites for CAES systems. Since CAES storage caverns can be placed in salt, hard rock, or porous media, a site could be found in virtually all utility service areas. These secondary benefits could become increasingly important as utilities reassess their need for peaking and intermediate power capacity.

But, from a different perspective, the general view of CAES by utility executives seems to be that it is a high-risk technology that is even more site specific than conventional pumped storage. The facts that one operating plant exists in Germany, and that it is exceeding operational design specifications, were not known by most utility executives. In general, they thought that suitable sites would be difficult to find in their respective service areas. Hence, a conscientious effort to educate the utility community may assist CAES technology to realize its full future potential. These apparent advantages could play enhancing roles in the introduction and use of second generation large-scale storage technologies.

6.4 Regulatory Reforms

Historically, electric utilities were stable, safe investments that paid a lower return than unregulated companies precisely because they were less risky. The energy crisis, the concern over safe use of nuclear power, and regulatory changes and delays have detrimentally changed the financial situation of the nation's electric utilities. The new administration, with its promise of less government intervention, has stimulated a number of investigations looking into easing regulations for the utility industry. A special task force is expected to be formed to investigate what can be done about the financial situation of the electric utility industry. The House Energy Subcommittee on energy conservation and power is expected to hold a series of hearings to explore the concept of least-cost-investment strategies for utilities. Specifics to be examined by the subcommittee are utility deregulation, load-management techniques, and marginal-rate cost design. Although the primary purpose of these investigations is to spur the construction of nuclear power plants, these proposed reforms could stimulate the growth of large-scale storage plants as well.

Utility companies are also petitioning for new regulations at state public utility commissions. Not only are the traditional rate hearing issues such as size of rate base, allowable rate of return, and structure of rate schedules being addressed through petitions, but new issues to include:

- Should customers have to pay a return on capital invested in new facilities while the facilities are still under construction, or only after the facilities are completed?
- Should the customer or the stockholders pay for an expensive "bad guess" by management on need for a new generating plant?
- Should the customers or the stockholders pay when a generation facility is out of service due to a mishap, e.g., the Three Mile Island case?

The utility industry would like to be able to include in the rate base, the cost of proposed generation facilities which were ultimately cancelled. They argue that the decision to build was "reasonable" at the time it was made and that change in demand are difficult to predict. Utilities would also like to include the costs of construction in the rate base, as they occur, instead of when a project is complete. This approach, known as construction-work-in-progress (CWIP), means essentially that the financing costs are borne by present customers rather than the company. The Federal Energy Regulatory Commission, which sets wholesale electricity rates, only approves CWIP when the utility company can raise necessary funds in no other reasonable way. Should some or all of these regulatory reforms become reality, interest in building large capital-intensive storage plants might be expected to increase dramatically.

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