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THE WILLAMETTE BASIN COMPREHENSIVE STUDY OF WATER AND RELATED L--ETC(U)
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WILLAMETTE BASIN

COMPREHENSIVE STUDY

Water and Related Land Resources

APPENDIX J

POWER

WILLAMETTE BASIN TASK FORCE - PACIFIC NORTHWEST RIVER BASINS COMMISSION

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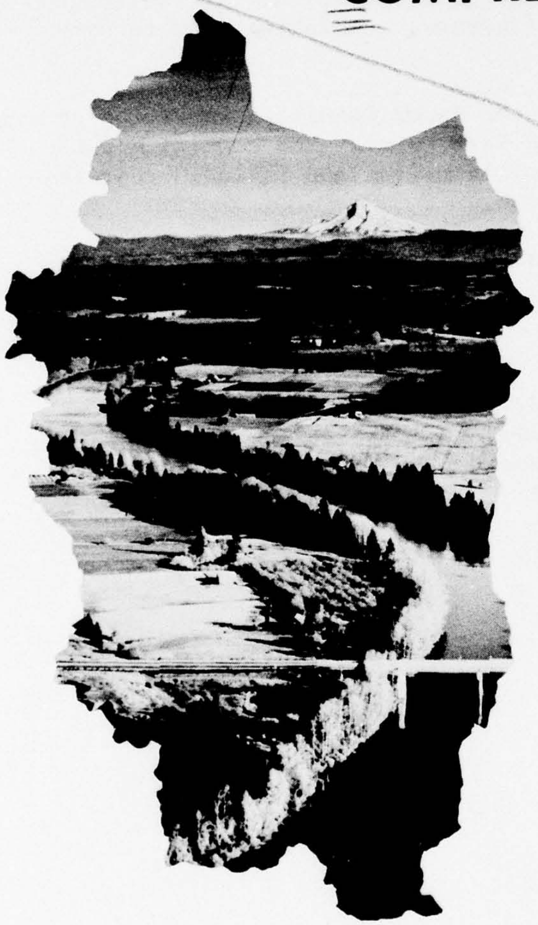
The WILLAMETTE BASIN

COMPREHENSIVE STUDY of

Water and Related Land Resources.



APPENDIX J.

POWER.

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CREDITS

This is one of a series of appendices to the Willamette Basin Comprehensive Study main report. Each appendix deals with a particular aspect of the study. The main report is a summary of information contained in the appendices plus the findings, conclusion, and recommendations of the investigation.

This appendix was prepared by the Power Committee under the general supervision of the Willamette Basin Task Force. The committee was chaired by the Bonneville Power Administration and included representation from the agencies listed below.

U. S. Army, Corps of Engineers
Federal Power Commission
Department of the Interior
  Bureau of Reclamation
  Geological Survey
  Bureau of Commercial Fisheries
  Federal Water Pollution Control Administration
Oregon State Water Resources Board
Oregon State Engineer's Office
Department of Agriculture

ORGANIZATION

PACIFIC NORTHWEST RIVER BASINS COMMISSION

Columbia Basin Inter-Agency Committee until 1967

WILLAMETTE BASIN TASK FORCE

State of Oregon - Chairman	Commerce
Army	Labor
Agriculture	Federal Power Commission
Interior	Health, Education and Welfare

REPORT WRITER

TECHNICAL STAFF

Army	Interior
Agriculture	State

PLAN FORMULATOR

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A. Study Area	G. Land Measures and Watershed Protection
B. Hydrology	H. Municipal and Industrial Water Supply
C. Economic Base	I. Navigation
D. Fish and Wildlife	J. Power
E. Flood Control	K. Recreation
F. Irrigation	L. Water Pollution Control
	M. Plan Formulation

WILLAMETTE BASIN TASK FORCE

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Federal Power Commission	Gordon N. Boyer Hydraulic Engineer Federal Power Commission
Department of Labor	Horace Harding Regional Economist Bureau of Employment Security
Department of Health, Education & Welfare	Francis L. Nelson Public Health Service Water Supply and Sea Resources Program

The Willamette Basin Comprehensive Study has been directed and coordinated by the Willamette Basin Task Force, whose membership as of April 1969 is listed above. The Task Force has been assisted by a technical staff, a plan formulator, and a report writer - Executive Secretary. Appendix committees listed on the following page carried out specific technical investigations.

APPENDIX COMMITTEES

Appendix-Subject		
A - Study Area	OSWRB - Chairman:	FWPCA, USBPA, USBLM, USBM, USBOR, USBR, USBSF&WL, USCE, USERS, USFS, USGS, USNPS, USSCS, OSDC, OSDF, OSDG&MI, OSS&WCC, OSU
B - Hydrology	USGS - Chairman:	FWPCA, USBPA, USBR, USCE, USSCS, USWB, OSE, OSWRB
C - Economic Base	USCE - Chairman:	FWPCA, USBPA, USBCF, USBM, USBOR, USBR, USBSF&WL, USDL, USERS, USFS, OSDC, OSU, UO, PSC-PR&C
D - Fish & Wildlife	USBSF&WL - Chairman:	FWPCA, USBCF, USBLM, USBOR, USCE, USDA, USFS, USGS, USSCS, OSFC, OSGC, OSWRB, USHEW
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F - Irrigation	USBR - Chairman:	USSCS, OSDC, OSWRB, OSU
G - Land Measures and Watershed Protection	USSCS - Chairman:	FWPCA, USBCF, USBLM, USBOR, USBR, USBSF&WL, USFS, OSU
H - M&I Water Supply	FWPCA - Chairman:	USBR, USBSF&WL, USGS, USSCS, OSBH, OSDC, OSWRB, USHEW
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J - Power	USBPA - Chairman:	FPC, FWPCA, USBCF, USBR, USCE, USFS, USGS, OSE, OSWRB
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L - Water Pollution Control	FWPCA - Chairman:	USBCF, USBLM, USBOR, USBR, USBSF&WL, USGS, USSCS, OSBH, OSE, OSFC, OSGC, OSWRB, OSU, USHEW
M - Plan Formulation	Plan Formulator - Chairman:	USCE, USDA, USDI, OSWRB

FPC - Federal Power Commission
FWPCA - Federal Water Pollution Control Administration
USBPA - Bonneville Power Administration
USBCF - Bureau of Commercial Fisheries
USBLM - Bureau of Land Management
USBM - Bureau of Mines
USBOR - Bureau of Outdoor Recreation
USBR - Bureau of Reclamation
USBSF&WL - Bureau of Sport Fisheries and Wildlife
USCE - Corps of Engineers
USDA - Department of Agriculture
USHEW - Department of Health, Education and Welfare
USDI - Department of Interior
USDL - Department of Labor
USERS - Economic Research Service
USFS - Forest Service
USGS - Geological Survey
USNPS - National Park Service
USSCS - Soil Conservation Service
USWB - Weather Bureau

OSBH - Oregon State Board of Health
OSDC - Oregon State Department of Commerce
OSDF - Oregon State Department of Forestry
OSDG&MI - Oregon State Department of Geology and Mineral Industries
OSE - Oregon State Engineer
OSFC - Fish Commission of Oregon
OSGC - Oregon State Game Commission
OSHD-PD - Oregon State Highway Department - Parks Division
OSMB - Oregon State Marine Board
OSS&WCC - Oregon State Soil and Water Conservation Committee
OSWRB - Oregon State Water Resources Board
OSU - Oregon State University
PSC-PR&C - Portland State College - Center for Population Research and Census Service
UO - University of Oregon
LCPD - Land County Parks Department
OCPA - Oregon County Parks Association
POP - Port of Portland

BASIN DESCRIPTION

Between the crests of the Cascade and Coast Ranges in northwestern Oregon lies an area of 12,045 square miles drained by Willamette and Sandy Rivers--the Willamette Basin. Both Willamette and Sandy Rivers are part of the Columbia River system, each lying south of lower Columbia River.

With a 1965 population of 1.34 million, the basin accounted for 68 percent of the population of the State of Oregon. The State's largest cities, Portland, Salem, and Eugene, are within the basin boundaries. Forty-one percent of Oregon's population is concentrated in the lower basin subarea, which includes the Portland metropolitan area.

The basin is roughly rectangular, with a north-south dimension of about 150 miles and an average width of 75 miles. It is bounded on the east by the Cascade Range, on the south by the Calapooya Mountains, and on the west by the Coast Range. Columbia River, from Bonneville Dam to St. Helens, forms a northern boundary. Elevations range from less than 10 feet (mean sea level) along the Columbia, to 450 feet on the valley floor at Eugene, and over 10,000 feet in the Cascade Range. The Coast Range attains elevations of slightly over 4,000 feet.

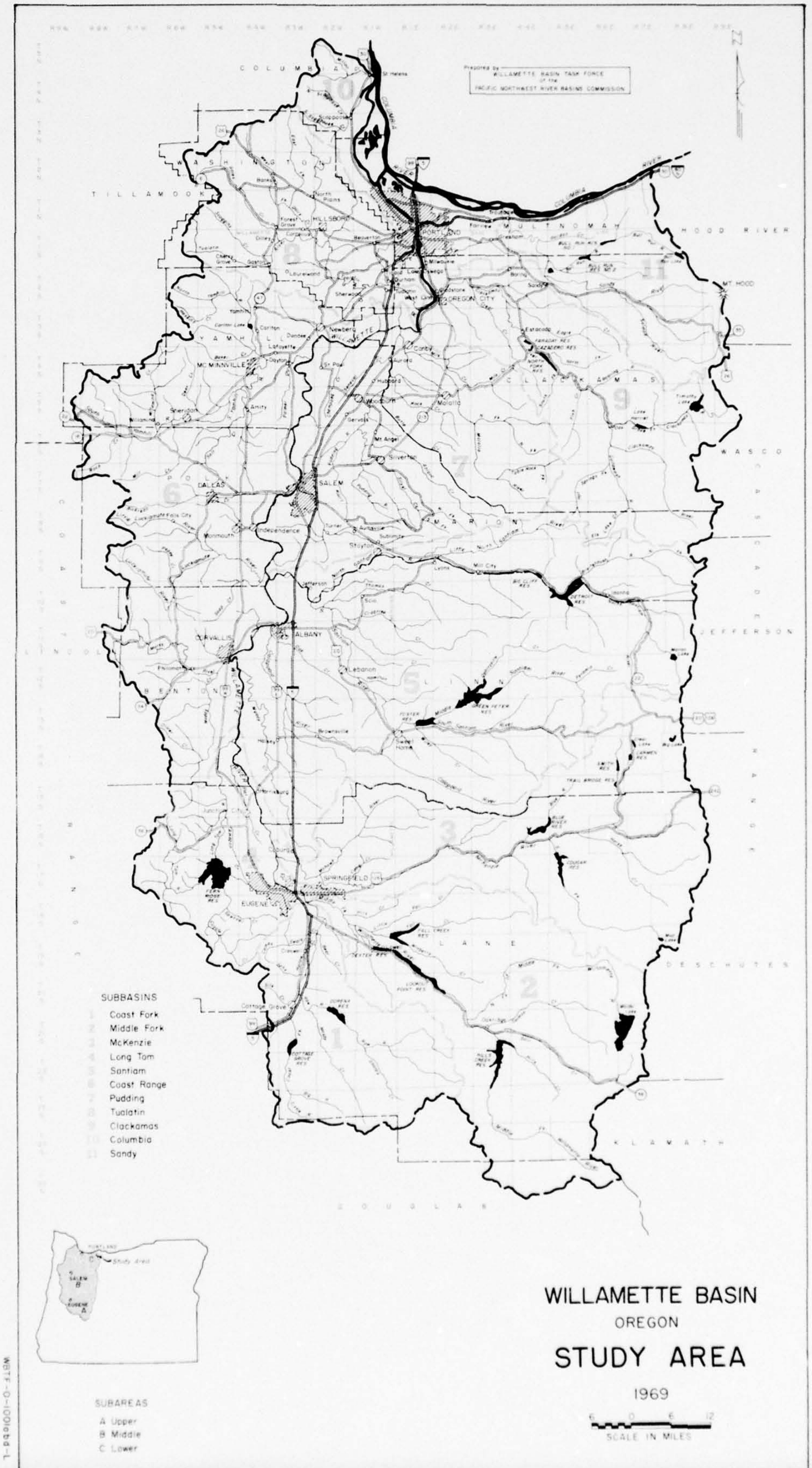
The Willamette Valley floor, about 30 miles wide, is approximately 3,500 square miles in extent and lies below an elevation of 500 feet. It is nearly level in many places, gently rolling in others, and broken by several groups of hills and scattered buttes.

Willamette River forms at the confluence of its Coast and Middle Forks near Springfield. It has a total length of approximately 187 miles, and in its upper 133 miles flows northward in a braided, meandering channel. Through most of the remaining 54 miles, it flows between higher and more well defined banks unhindered by falls or rapids, except for Willamette Falls at Oregon City. The stretch below the falls is subject to ocean tidal effects which are transmitted through Columbia River.

Most of the major tributaries of Willamette River rise in the Cascade Range at elevations of 6,000 feet or higher and enter the main stream from the east. Coast Fork Willamette River rises in the Calapooya Mountains, and numerous smaller tributaries rising in the Coast Range enter the main stream from the west.

In this study, the basin is divided into three major sections, referred to as the Upper, Middle, and Lower Subareas (see map opposite). The Upper Subarea is bounded on the south by the Calapooya Mountains and on the north by the divide between the McKenzie River drainage and the Calapooia and Santiam drainages east of the valley floor and by the Long Tom-Marys River divide west of it. The Middle Subarea includes all lands which drain into Willamette River between the mouth of Long Tom River and Fish Eddy, a point three miles below the mouth of Molalla River. The Lower Subarea includes all lands which drain either into Willamette River from Fish Eddy to its mouth or directly into Columbia River between Bonneville and St. Helens; Sandy River is the only major basin stream which does not drain directly into the Willamette.

For detailed study, the three subareas are further divided into 11 subbasins as shown on the map.



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P U R P O S E A N D S C O P E

The purpose of this Appendix is to show the present power needs and existing generating capacity in the Willamette Basin, to determine future power needs, to identify potential projects in the basin which could be developed for power generation, and to evaluate potential projects as to their utility for power development. The power potentials within the basin are presented from a single-purpose viewpoint to determine the maximum extent to which the water resource could be developed for power generation.

Power requirements, load characteristics, interconnections, and power-source potentials are projected to the years 1980, 2000, and 2020. These projections are the basis for planning long-range, comprehensive water resource development. The 1980 estimates provide the basis for development of a plan to meet early power needs of the basin. The longer-term appraisals are more conjectural and tentative.

A brief "Glossary of Power and Rate Terms," as used throughout this study, is included at the end of this Appendix.

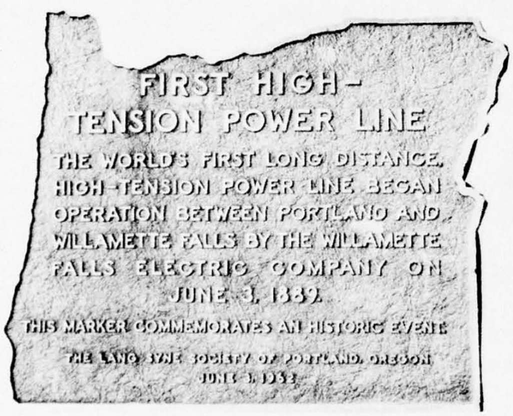
R E L A T I O N S H I P T O O T H E R P A R T S O F R E P O R T

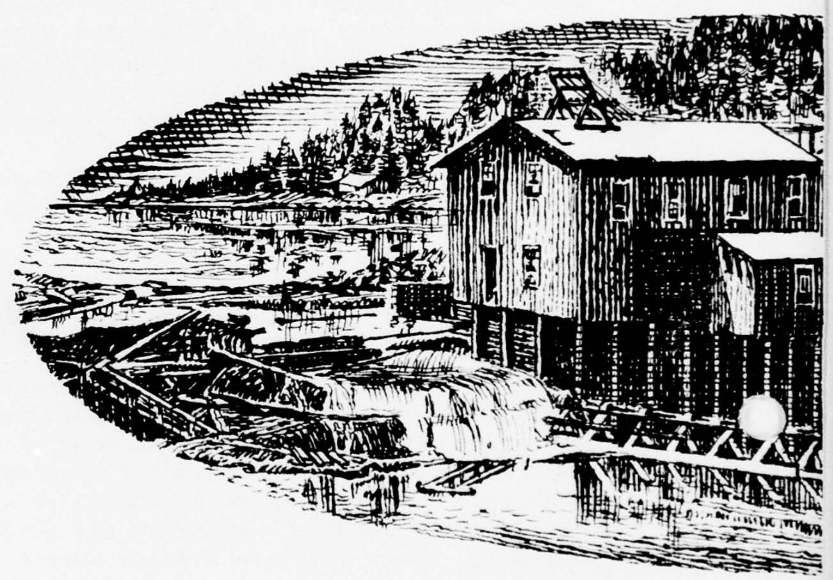
This Appendix draws upon data contained in the three supporting appendices--A - Study Area, B - Hydrology, and C - Economic Base. It is related more specifically to some of the functional appendices, and data developed in this and other appendices are used interchangeably as required. Power is closely related to irrigation because it is used to operate irrigation pumps during the summer months (Appendix F - Irrigation). Power directly affects forest management because of the need for transmission line corridors (Appendix G - Land Measures and Watershed Protection) and land use for power sites. Also, thermal generating plants may have an impact on the water temperature of streams on which they are located (Appendix L - Water Pollution Control.)

This Appendix provides the background for the power presentation in Appendix M and the main report. The relationship of power to all the other functions of multipurpose water resource development is covered in detail in Appendix M - Plan Formulation.

HISTORY

Use of water for power in the Willamette Basin was introduced by the early Oregon settlers. The first water-power development was undertaken about 1838 by Dr. John McLaughlin, who erected a sawmill which used a water wheel for power on Abernethy Island at Oregon City. In subsequent years, enterprises using the power of falling water at Willamette Falls were established. Those firms constructed low-head timber dams and flumes to divert sufficient water to drive their rather crude wooden water wheels. The first water-driven turbine in Oregon was installed on Silver Creek near Silverton in 1850. Thereafter, water was developed for power in many new settlements.





The first generation of hydroelectric power in the basin, by the Oregon City Electric Company, took place in 1888; a plant was built at Willamette Falls to supply electric energy to Portland and Oregon City. In 1889, a new plant was put into operation by Willamette Falls Electric Company, which transmitted power to Portland in the form of direct current for street lighting. Alternating-current generators were installed in that plant early in 1890. The first long-distance transmission of alternating-current power in the United States was made from that plant to Portland that year.

Late in 1895, three 450-kilowatt generators went into service at Willamette Falls. This was the first stage of construction of a new powerhouse (the present T. W. Sullivan Plant) built by Portland General Electric Company. During those early years, several companies were developing water power for paper-making purposes. Water wheels were installed to drive pulp grinders and other machinery and to produce electric power for consumption on the premises; these forms of hydraulic power are still being used by the present companies--Crown Zellerbach Corporation and Publishers Paper Company.

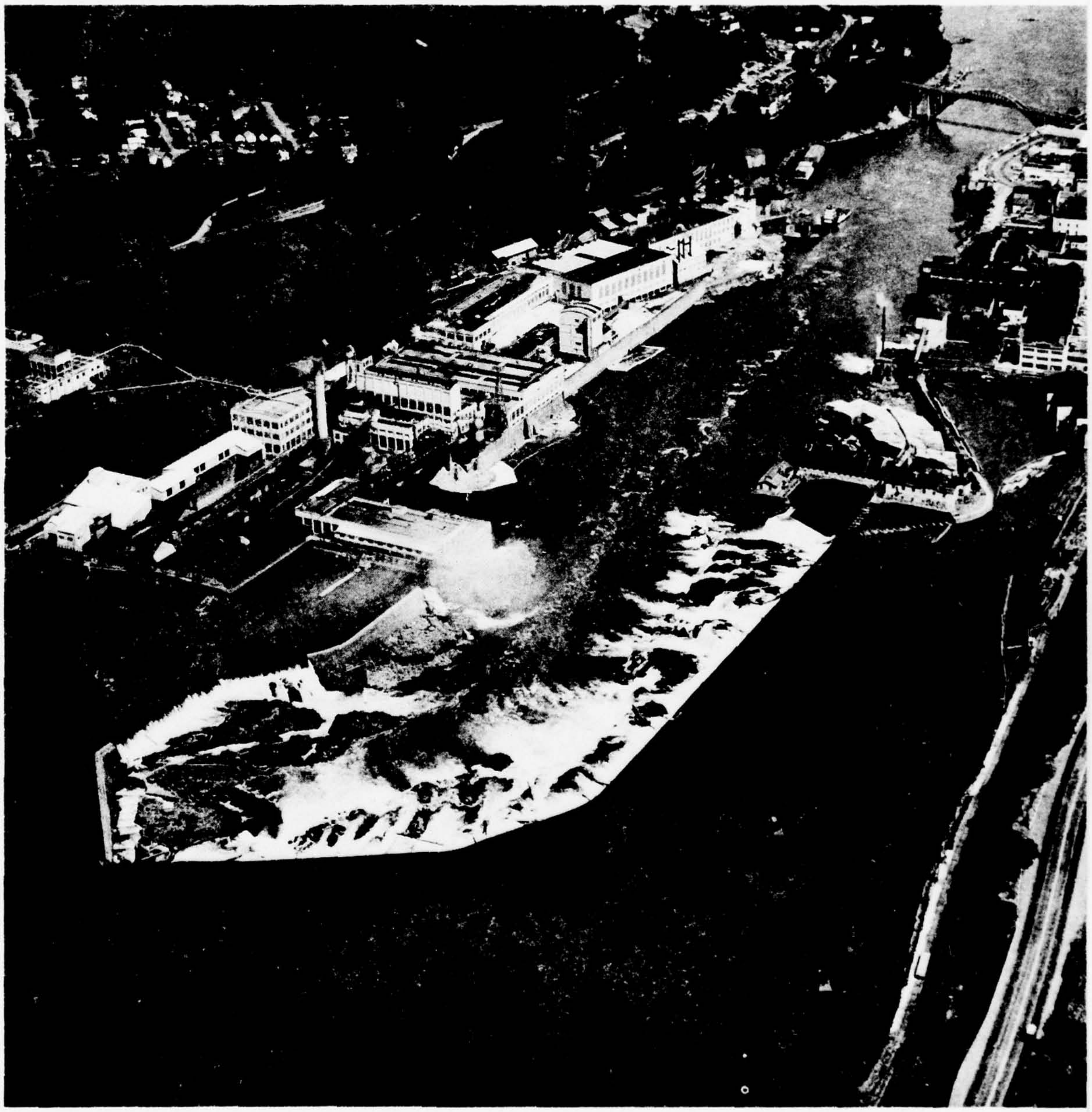


Photo I-1. Plants Using Waterpower at Willamette Falls, Oregon City (Crown Zellerbach Photo).

Following the initial start at Willamette Falls, hydroelectric power was developed on other streams in the basin. Portland General Electric Company constructed Faraday in 1907 and River Mill in 1911 on the Clackamas River, and Bull Run on the Bull Run River in 1912. In 1911, the City of Eugene built Walterville on the McKenzie River. Those plants are still in operation today, although numerous changes, alterations, and improvements have been made through the years. In 1924, Portland General Electric Company constructed Oak Grove on the Clackamas River, and in 1929 the City of Eugene built Leaburg on the McKenzie River.

Some of the earlier major hydroelectric developments in the basin are tabulated below:

Table I-1
Early Hydroelectric Power Development

Name of Project	Present Owner	River	Initial Capacity	Initial Date in Service
Sullivan	PGE	Willamette	1,350 KW	1895
Faraday	PGE	Clackamas	7,500 KW	1907
River Mill	PGE	Clackamas	6,600 KW	1911
Walterville	City of Eugene	McKenzie	1,128 KW	1911
Bull Run	PGE	Bull Run	11,250 KW	1912
Oak Grove	PGE	Clackamas	25,500 KW	1924
Leaburg	City of Eugene	McKenzie	6,000 KW	1929
Westfir	Westfir Lumber	N.Fk.Willamette	1,950 KW	

PGE: Portland General Electric Company

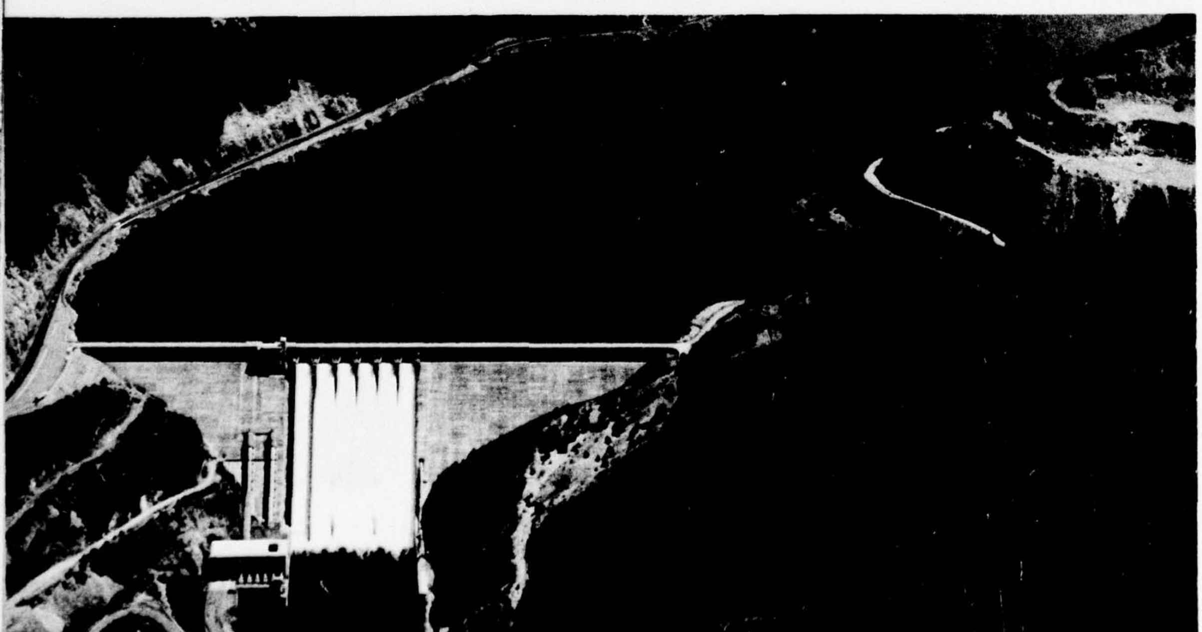


Photo I-2. Detroit Dam, North Santiam River (USCE Photo)

No major hydro power development took place in the Willamette River Basin for the next 20 years. In 1953, Detroit Dam on the North Santiam River, the first of the Corps of Engineers projects with generating facilities, was put into service. In the following years, seven more Corps of Engineers projects and several nonfederal projects with generating facilities were built in the basin.

The development of thermal-electric power in the Willamette Basin has been slow due to the abundance of low-cost hydropower in the Pacific Northwest and the high cost of fuel-electric plants. During the early stages of power development, prior to the transmission network of today, a number of steam plants were built to serve particular load centers. The following tabulation lists some of the older steam plants and the McMinnville internal combustion plant:

Table I-2
Early Steam and Internal Combustion Plants

Name of Project	Present Owner	Location	Initial Capacity	Initial Date in Service
Station "E"	PGE	Portland	2,000 KW	1904 Ret.
Springfield	PP&L	Springfield	800 KW	1906
Station "H"	PGE	Salem	1,000 KW	1906 Ret.
Station "L"	PGE	Portland	2,000 KW	1910
Station "N"	PGE	Portland	2,500 KW	1911 Ret.
Pittock	PP&L	Portland	7,000 KW	1914 Ret.
Lincoln	PP&L	Portland	7,500 KW	1919
Willamette Valley Lumber Company	Willamette Val. Lumber Co.	Dallas	5,250 KW	1920
McMinnville	City of McMinnville	McMinnville	2,740 KW	1926
Eugene	City of Eugene	Eugene	6,000 KW	1931

PGE : Portland General Electric Company
PP&L: Pacific Power & Light Company
Ret.: Retired.

For nearly 50 years after the first long-distance transmission line was placed in service, power transmission facilities were developed primarily on a local needs basis. Generating plants were generally located near the load centers, and only sufficient transmission facilities were constructed to deliver power to these centers. In the late 1930's, Federal high-voltage (230,000-volt) transmission lines were constructed to carry Bonneville and Grand Coulee power to the Portland and Seattle load centers. It was then that a regionally integrated transmission and distribution system began to develop. A Federal 115,000-volt power line was constructed from Portland to Eugene by 1940. By that time, Portland General Electric Company had built 57,000-volt transmission lines and distribution lines in the Willamette Valley north of Salem. Northwestern Electric Company also served a part of the Portland area. Mountain States Power Company built transmission lines up to 66,000 volts to serve the Willamette Valley south of Salem. California Oregon Power Company was interconnected to the Willamette transmission grid during that time. The transmission facilities of the latter three companies are now owned and operated by Pacific Power and Light Company. Today, the Willamette Basin has a vast network of transmission and distribution facilities.

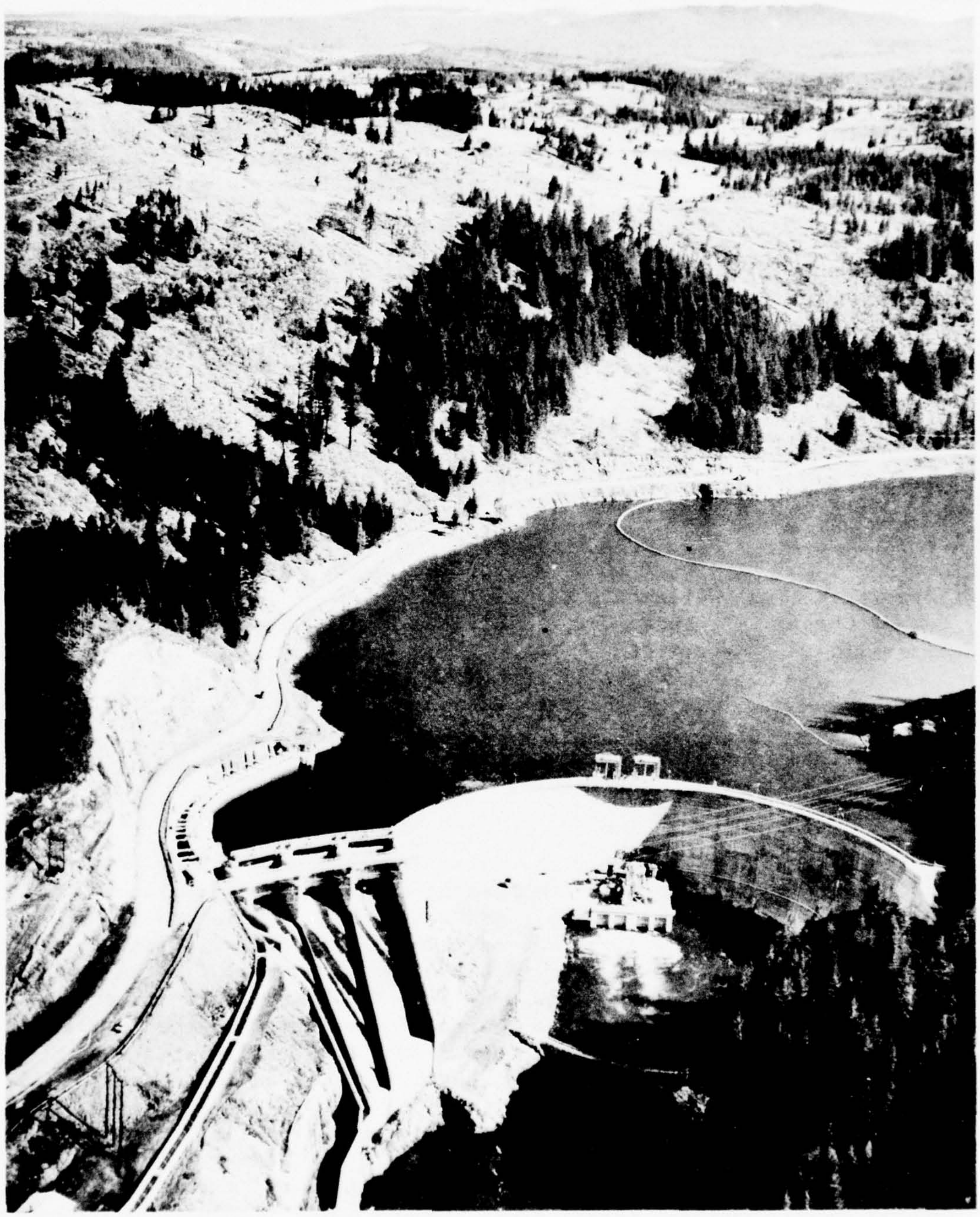
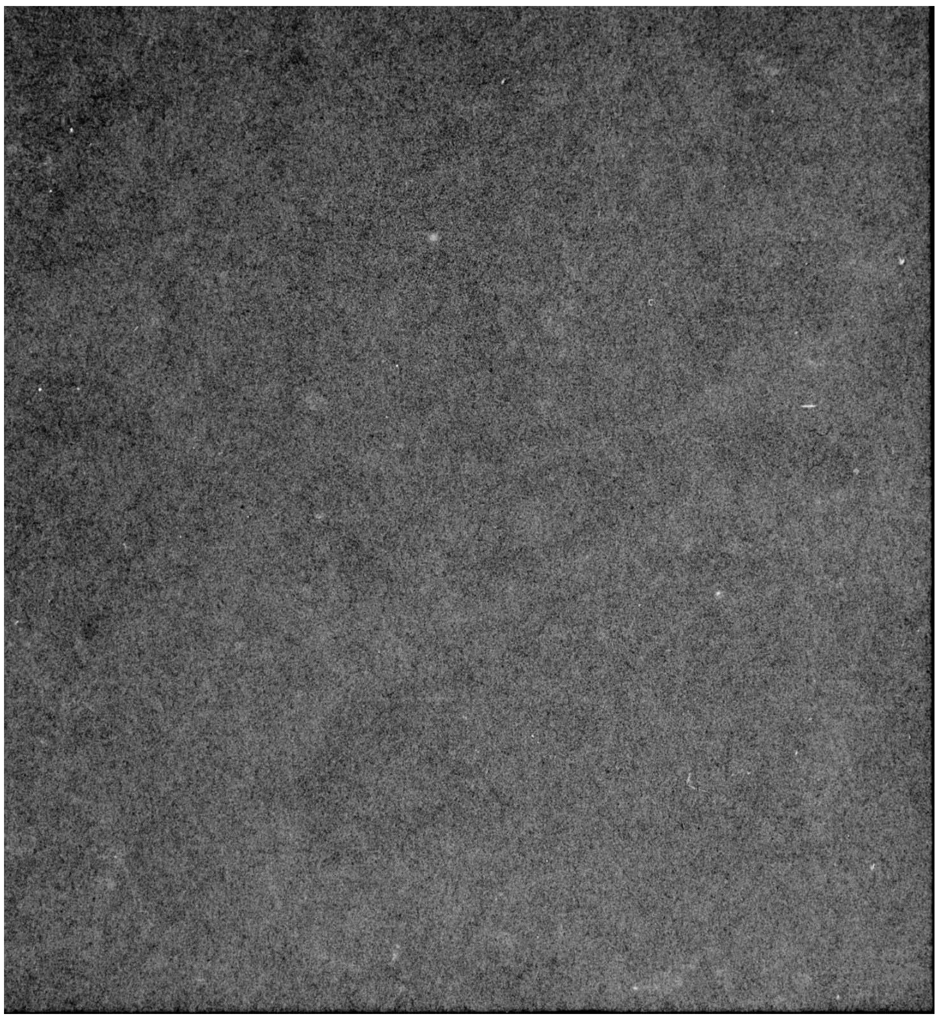


Photo I-3. North Fork Dam, Clackamas River (Portland General Electric Company Photo).

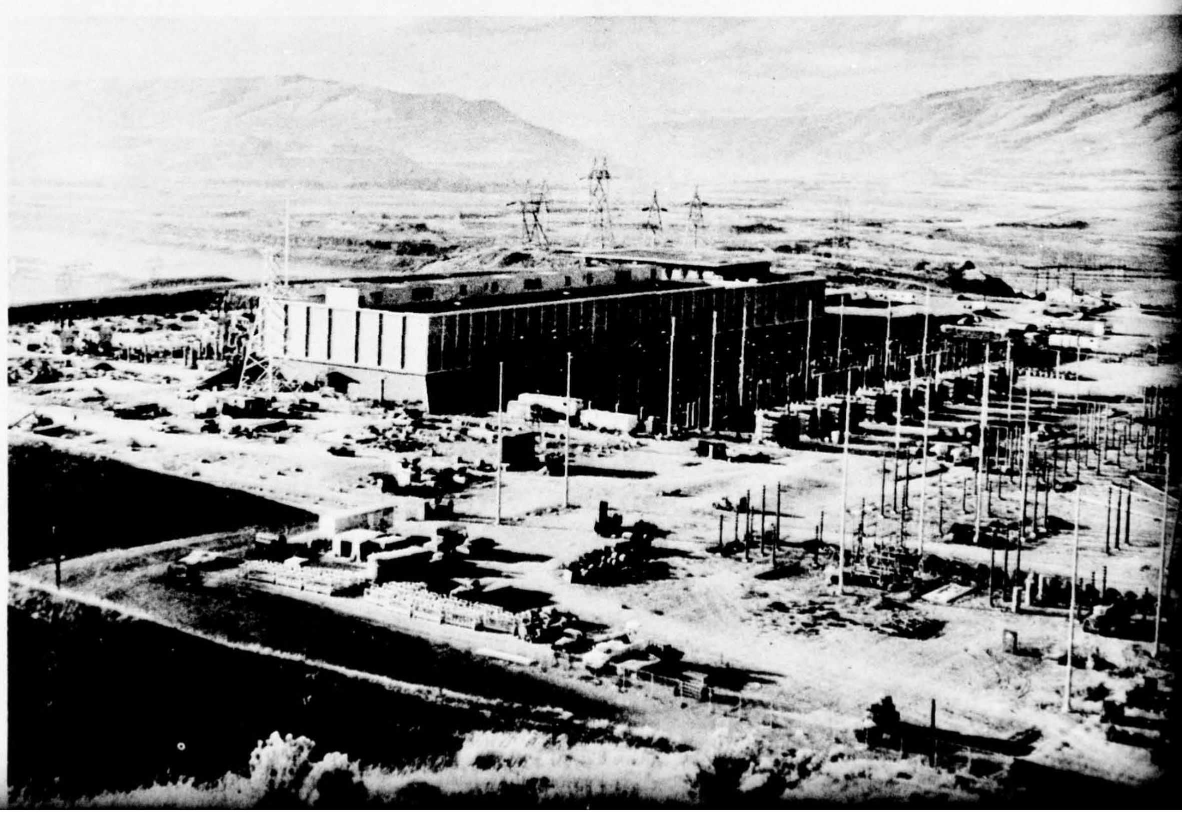


The Willamette Basin differs hydrologically from areas east of the Cascade Range, where most of the region's major hydroelectric facilities are located. Fall and winter storms in the Basin increase water supplies and, therefore, power generation, at a time when streamflows in the eastern portion of the region are normally low. Northwest hydroelectric power projects are shown on Map II-1.

The Willamette Basin is strongly dependent upon out-of-basin sources for electric power. The Willamette Basin contains less than 5 percent of the Pacific Northwest region's land area and about 5 percent of its installed generating plant capacity. However, the basin's power requirements are about 23 percent of the regional load. Transmission lines in the basin are interconnected with the rest of the Pacific Northwest regional power grid and power flows into and out of the Willamette Basin as required. Over 75 percent of the present power supply is imported.

Other power market areas, intertied with the Pacific Northwest Region, can use surplus Northwest secondary energy and peaking capacity during their heavy load periods. In turn, these other areas can provide energy during their minimum-load periods to firm up some of the secondary energy generated in the Northwest. Construction is already completed on part of the Pacific Northwest-Pacific Southwest Intertie, the biggest single electrical transmission program ever undertaken in the United States. Other interties, such as a tie with the Missouri Basin, and the Central sectors of the United States, are being investigated.

Photo II-1. Celilo D-C Substation Under Construction - Part of Pacific Northwest-Pacific Southwest Intertie (USBPA Photo).



POWER REQUIREMENTS

A large portion of the power requirements in the Middle and Upper Subareas are attributable to the lumber industry and its supporting services. Forest products are supplied for use throughout the world. Most of these products are distributed from the Port of Portland, a major West Coast seaport, and a terminal for rail and barge traffic, in the Lower Subarea. The largest individual industrial power users in the Basin are the primary metals producers near Albany and Portland. The Willamette Basin has many small industries and commercial enterprises. These power requirements, coupled with domestic power requirements of the heavily populated valley, make the Willamette Basin one of the major electrical load centers in the Pacific Northwest. The basin's peak load currently amounts to some 3 million kilowatts.

Industrial use by about 1,000 customers amounts to 37 percent of the total load. The largest user group (numerically) is the 400,000 plus domestic customers who create about 35 percent of the basin's total energy requirements. Commercial establishments buy nearly 18 percent, while about 2 percent is used for irrigation and other purposes. Transmission and distribution losses amount to about 8 percent.

Details of electric energy sales for 1965 are shown on Table II-1.

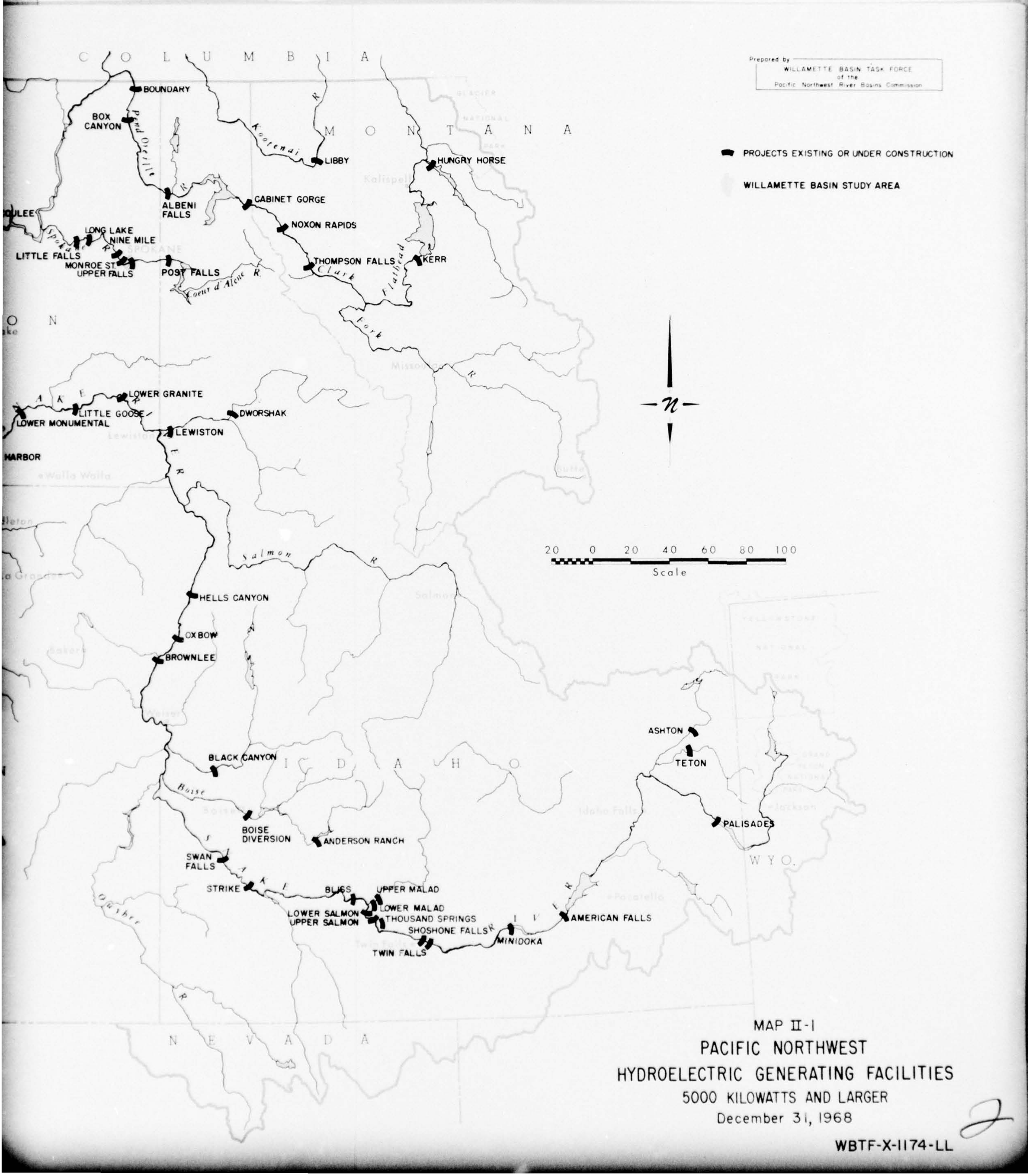
Table II-1
Electric Energy Sales
Willamette Basin - 1965

	Customers	Energy (1,000 kilowatt hours)	Percent of Total
Industrial	1,034	5,040,000	37.0
Domestic	405,091	4,801,000	35.3
Commercial	52,395	2,385,000	17.5
Irrigation & Other	6,303	273,000	2.0
Losses		1,119,000	8.2
Total	464,823	13,618,000	100.0

LOAD CHARACTERISTICS

Load characteristics of the Willamette Basin are typical of those experienced elsewhere in the Pacific Northwest. That is, peak loads occur in the winter months when daylight is short and when electrical heating accentuates the normal increase in power usage. The summer loads which are normally lower have neither the high irrigation pumping


BRITISH COLUMBIA
PACIFIC OCEAN
WASHINGTON
OREGON
CALIFORNIA
NEVADA
BOUNDARY
BOX CANYON
DIABLO
ROSS
UPPER BAKER
GORGE
LOWER BAKER
CHIEF JOSEPH
GRAND COULEE
ALBENI FALLS
CABINET
WELLS
CHELAN
LONG LAKE
NINE MILE
LITTLE FALLS
MONROE ST
UPPER FALLS
POST FALLS
CUSHMAN NO. 1
CUSHMAN NO. 2
SNOQUALMIE FALLS
CEDAR FALLS
ROCKY REACH
ROCK ISLAND
WHITE RIVER
ELECTRON
YELM
LA GRANDE
ALDER
WANAPUM
NACHES
ROZA
PRIEST RAPIDS
MOSSYROCK
MAYFIELD
PACKWOOD LAKE
LOWER GRANITE
LITTLE GOOSE
LOWER MONUMENTAL
DWORSHAK
LEWISTON
SWIFT NO. 2
SWIFT NO. 1
YALE
MERWIN
CHANDLER
ICE HARBOR
MCNARY
CONDIT
BONNEVILLE
JOHN DAY
POWERDALE
THE DALLES
BULL RUN
SULLIVAN
RIVER MILL
FARADAY
NORTH FORK
OAK GROVE
TIMOTHY MEADOWS
HELLS CANYON
PELTON
ROUND BUTTE
OXBOW
BROWNLEE
BIG CLIFF
DETROIT
GREEN PETER
FOSTER
CARMEN
TRAIL BRIDGE
LEABURG
WATERVILLE
COUGAR
DEXTER
LOOKOUT POINT
BLACK CANYON
HILLS CREEK
TOKETEE
SLIDE CREEK
SODA SPRINGS
LEMOLO NO. 1
LEMOLO NO. 2
CLEARWATER NO. 1
CLEARWATER NO. 2
FISH CREEK
BOISE DIVERSION
SWAN FALLS
STRIKE
PROSPECT #1, #2, #4
#3
LOST CREEK
GREEN SPRINGS
IRON GATE
COPCO #1
COPCO #2
Bellingham
Everett
Skagit
Okanogan R.
Pend Oreille
Kootenai
Spokane R.
SPOKANE
Coeur d'Alene R.
Quinault R.
Hoquiam
Aberdeen
Olympia
Chehalis R.
Cowlitz
Wenatchee
Moses Lake
Grand Coulee
Yakima
Yakima R.
Columbia
Columbia R.
Snake R.
Lewiston
Walla Walla
Astoria
Kelso
Longview
Vancouver
PORTLAND
Tillamook
Pendleton
The Dalles
La Grande
Salmon
Salem
Newport
John Day R.
Baker
Willamette R.
Deschutes R.
Eugene
Bend
Umpqua R.
Coos Bay
Roseburg
Burns
Malheur Lake
Boise R.
Boise
Owyhee R.
Rogue R.
Grants Pass
Medford
Klamath R.



MAP II-1

PACIFIC NORTHWEST

HYDROELECTRIC GENERATING FACILITIES

5000 KILOWATTS AND LARGER

December 31, 1968

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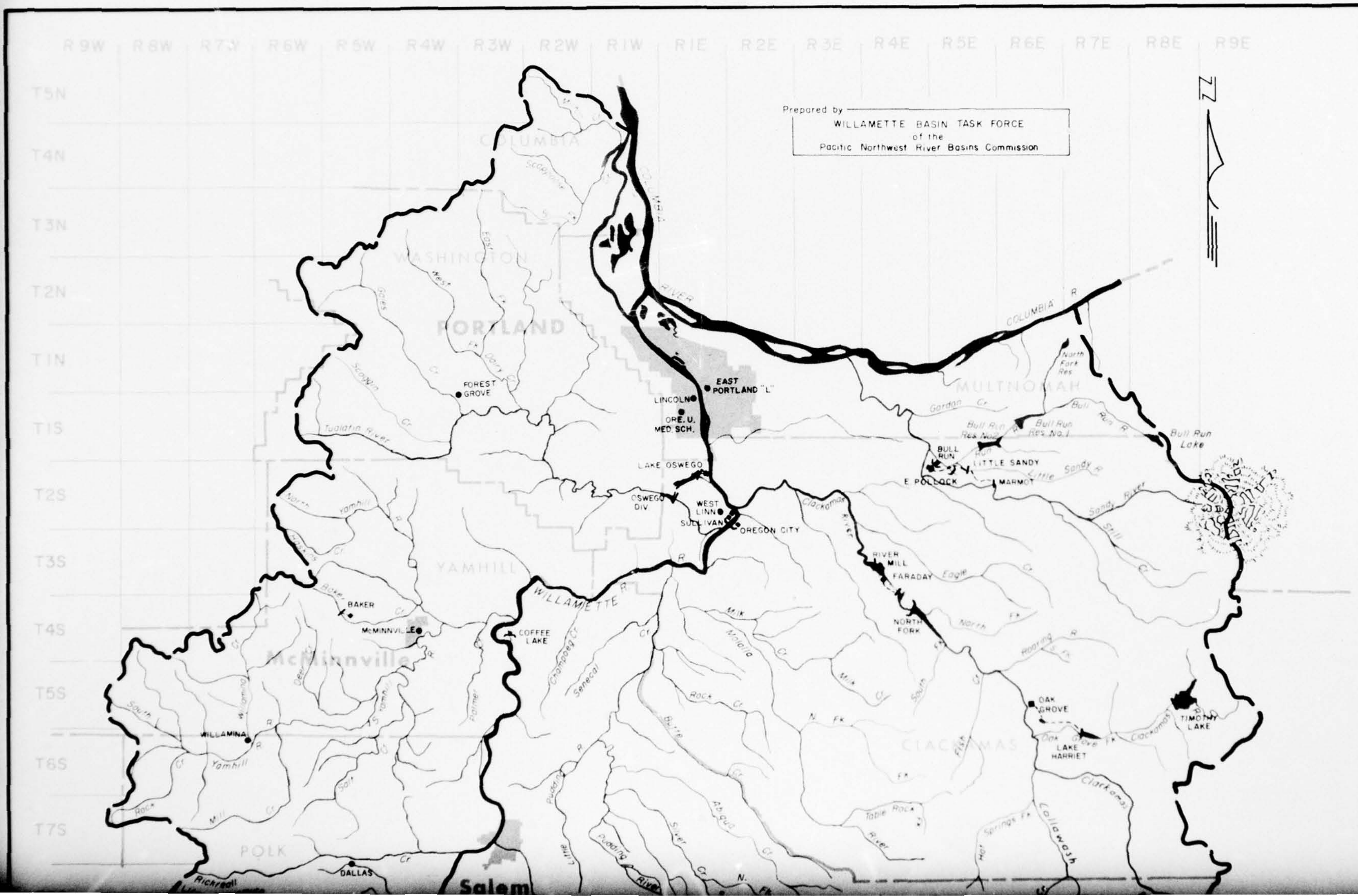

Prepared by
WILLAMETTE BASIN TASK FORCE
of the
Pacific Northwest River Basins Commission
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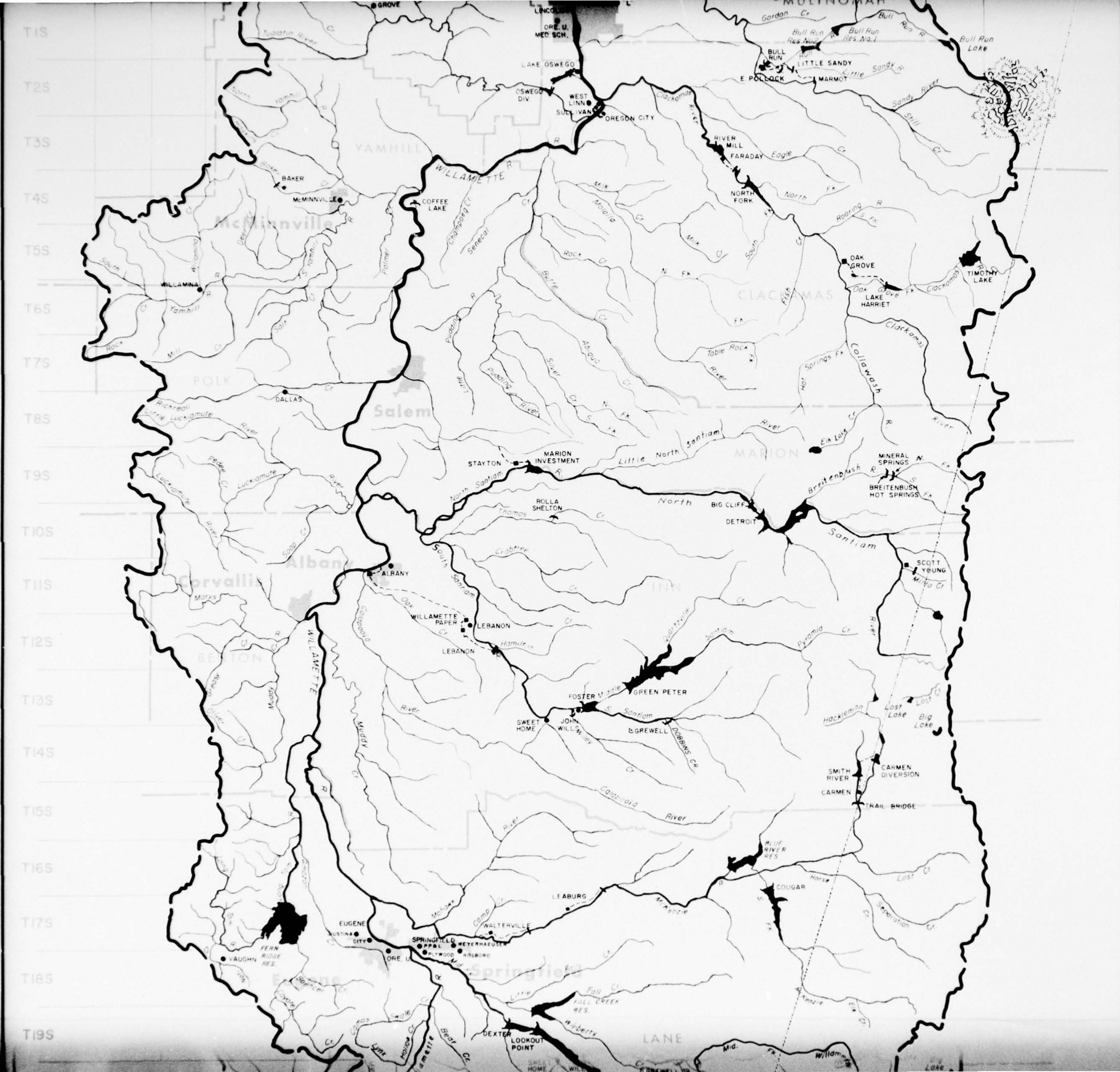
T5N T4N T3N T2N T1N T1S T2S T3S T4S T5S T6S T7S
COLUMBIA
WASHINGTON
PORTLAND
MULTNOMAH
YAMHILL
CLACKAMAS
POLK
McMinnville
Salem
COLUMBIA R
RIVER
WILLAMETTE R
EAST PORTLAND "L"
LINCOLN
ORE. U. MED. SCH.
LAKE OSWEGO
OSWEGO DIV
WEST LINN
SULLIVAN
OREGON CITY
FOREST GROVE
BAKER
McMINNVILLE
COFFEE LAKE
WILLAMINA
DALLAS
BULL RUN
LITTLE SANDY
E POLLOCK
MARMOT
RIVER MILL
FARADAY
NORTH FORK
OAK GROVE
LAKE HARRIET
TIMOTHY LAKE
North Fork Res
Bull Run Res No.2
Bull Run Res No.1
Bull Run Lake
Bull Run R
Gordon Cr
Sandy River
Little Sandy R
Still Cr
Clackamas River
Eagle Cr
North Fk
Roaring R
Milk Cr
Molalla
Rock Cr
Butte Cr
Abiqua Cr
Silver Cr
Pudding River
Table Rock Fk
Collawash
Hot Springs Fk
Champoeg Cr
Senecal
Palmer
Tualatin River
Scoggin Cr
Gales Cr
Dairy Cr
Yamhill R
Salt Cr
Mill Cr
Rickreall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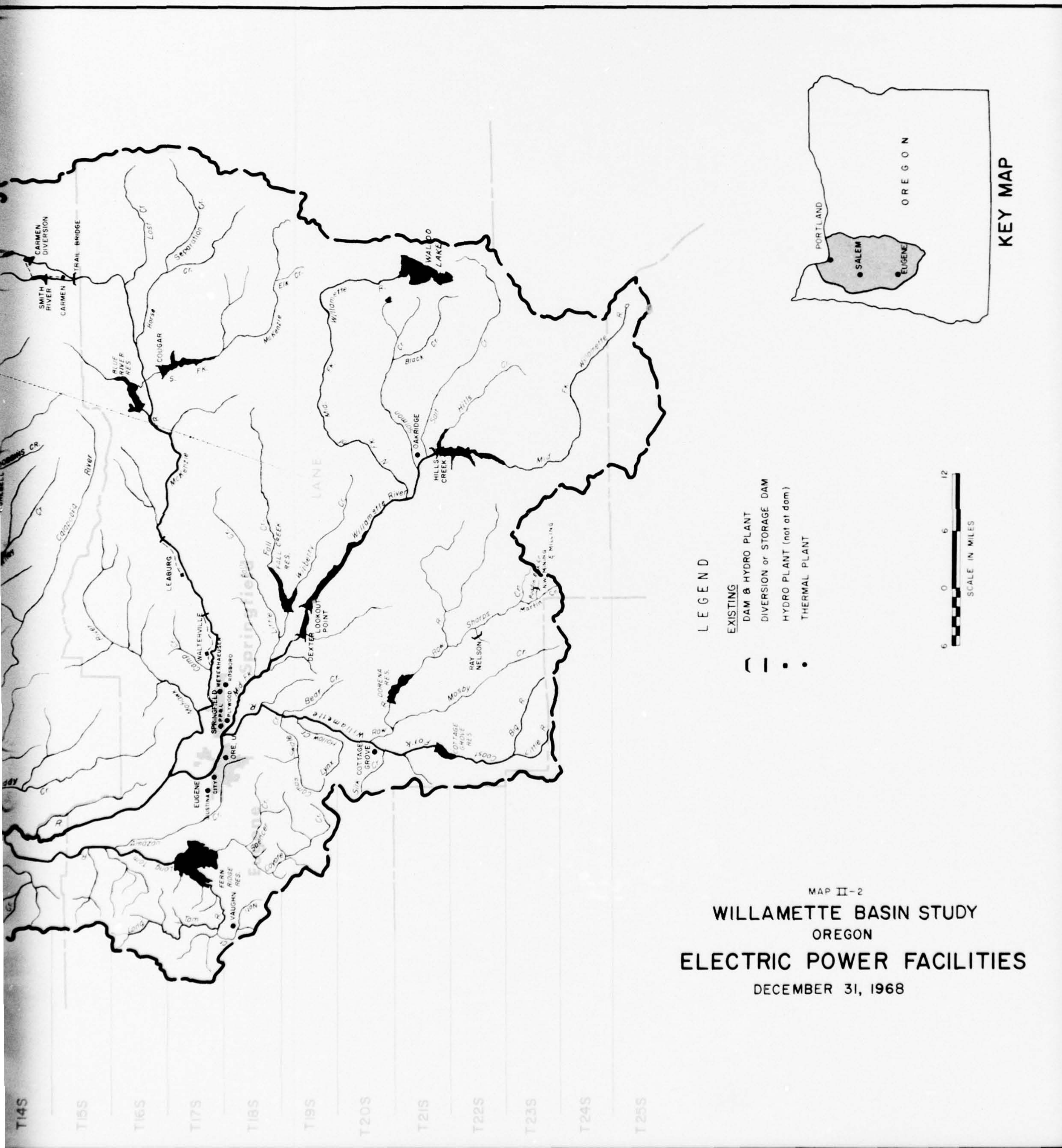
LITTLE SANDY
E POLLOCK
MARMOT
RIVER MILL
FARADAY
NORTH FORK
OAK GROVE
LAKE HARRIET
TIMOTHY LAKE
COFFEE LAKE
BAKER
McMINNVILLE
WILLAMINA
DALLAS
STAYTON
MARION INVESTMENT
ROLLA SHELTON
MINERAL SPRINGS
BREITENBUSH HOT SPRINGS
BIG CLIFF
DETROIT
SCOTT YOUNG
ALBANY
WILLAMETTE PAPER
LEBANON
FOSTER
GREEN PETER
SWEET HOME
JOHN WILLY
GREWELL
DOBBINS CR.
SMITH RIVER
CARMEN
CARMEN DIVERSION
TRAIL BRIDGE
BLUE RIVER RES.
COUGAR
LEABURG
WALTERVILLE
EUGENE
CITY
ORE. U.
SPRINGFIELD
WEYERHAEUSER
ROSBORO
PLYWOOD
FERN RIDGE RES.
VAUGHN
FALL CREEK RES.
DEXTER
LOOKOUT POINT
Collawash
Clackamas River
Santiam
Little North Santiam
North Santiam
South Santiam
Breitenbush R
Calapooia River
Muddy Cr.
McKenzie
Yamhill
Luckiamute
Pudding River
Molalla
Abiqua
Sandy River
Tualatin River



MAP II-2

WILLAMETTE BASIN STUDY

OREGON

ELECTRIC POWER FACILITIES

DECEMBER 31, 1968

WBTF-O-1175-LL

nor the heavy air-conditioning loads common in other areas in the West. Therefore, the spread between winter and summer loads in the basin is substantial; load requirements in 1964 ranged from a minimum of 1,679 megawatts in July to a peak of 2,792 megawatts in December.

The basin's peak demands are dominated by domestic and light industry requirements rather than by heavy industry. For other than the (above described) seasonal fluctuations, the peak requirements of the basin are relatively stable.

Load factor--the average energy requirement divided by the peak demand in the same period--is an indicator of load characteristics used throughout the power industry. Willamette Basin load factor in the peak month of December 1964 was 63 percent, whereas the load factor for the year was approximately 52 percent. The yearly load factor for the Pacific Northwest as a whole is about 65 percent.

POWER SOURCES

Total installed generating capacity in the Willamette Basin is about 938,000 kilowatts. The 35 existing hydroelectric generating projects in the Willamette Basin have a total nameplate rating of about 718,000 kilowatts. Authorized additions to the existing Cougar hydroelectric project would increase the total nameplate rating by 39,500 kilowatts. Additionally, the basin has 23 thermal power plants, with a total installed capacity of about 220,000 kilowatts.

Over half of the basin's hydroelectric generating capacity, 408,000 kilowatts, is installed at eight Corps of Engineers multipurpose projects. Public agencies built five hydroelectric projects with about 112,000 kilowatts of installed capacity; the City of Eugene operates four of these. A minor amount of the basin's hydroelectric power is generated at industrial firms for plant use. The 22 remaining hydroelectric projects in the basin, with an installed capacity of 198,000 kilowatts, are owned and operated by private entities. Hydroelectric projects in the basin range in size from Burnice Grewell's three-kilowatt plant located on Dobbins Creek in the South Santiam basin to the Corps of Engineers 120,000-kilowatt Lookout Point Powerplant on the Middle Fork Willamette River. Hydroelectric and thermal power plants in the basin are presented in Tables II-2 and II-3, respectively, and are shown on Map II-2.

For many years, power generation from other areas of the Pacific Northwest has been used to make up the difference between Willamette Basin power needs and generation within the basin. As mentioned before, over three-fourths of the basin's power supply was imported in fiscal year 1969. This power was imported by Bonneville Power Administration, Pacific Power and Light Company, and Portland General Electric Company.

Although generating facilities within the basin are under diverse ownerships, their operation is coordinated hydraulically and electrically with other utilities of the area to obtain the most effective utilization of water resources and electric power facilities.

Table II-2

Developed Waterpower Plants

December 31, 1968

Plant	Class	Location: Stream	Location: Stream Mile (Above Mouth)	Sec.	T.	R.	Mechanical Power Plants hp	Hydroelectric Plants: Installed Capacity KW	Peaking Capability KW	Usable Storage Acre-feet	Pool Elevation Feet	Gross Head feet
Upper Willamette Subarea												
Hills Creek	Fed.	M. Fk. Willamette	232.5	35	21S	3E	0	30,000	34,500	243,600	1541.0	318.0
Lookout Point	Fed.	M. Fk. Willamette	206.9	13	1[illegible]	1W	0	120,000	138,000	336,500	926.0	231.0
Dexter	Fed.	M. Fk. Willamette	203.8	9	19S	1W	0	15,000	17,250	4,800	695.0	57.0
Ray Nelson	Pri.	Glenwood Cr.	NA	NA			0	7*	7*	NA	NA	206.0
Carmen	Pub.	McKenzie	83.0	1	15S	6E	0	80,000	101,600	12,000	2605.0	513.0
Trail Bridge	Pub.	McKenzie	81.9	11	15S	6E	0	10,000	11,000	2,113	2092.0	78.0
Cougar	Fed.	S. Fk. McKenzie	4.5	31	16S	5E	0	25,000	28,750	154,000	1690.0	434.5
Leaburg	Pub.	McKenzie	33.3	9	17S	1E	0	13,500	14,820	0	734.0	90.0
Walterville	Pub.	McKenzie	24.5	29	17S	1W	0	8,000	9,500	345	598.0	56.0
Monroe Feed	Pri.	Long Tom	6.7*	33	14S	5W	20	0	0	0	NA	7.0
NW Mining & Milling	Pri.	Puddin Rock Cr.	1.5*	20	23S	1E	0	25*	25*	NA	NA	217.0
Subtotal							20	301,532	355,452	753,358		
Middle Willamette Subarea												
Thompson Mill	Pri.	Calapooia	23.5	8	13S	3W	205	0	0	0	NA	10.0
Scott Young	Pri.	Minto Cr.	0.1	15	11S	7E	0	59	59	0	NA	100.0
Mineral Springs	Pri.	Breitenbush	10.5*	20	9S	7E	0	35	35	0	NA	18.0
Breitenbush Hot Springs	Pri.	Breitenbush	10.3*	20	9S	7E	0	12	12	0	NA	7.0
Detroit	Fed.	North Santiam	60.9	7	10S	5E	0	100,000	115,000	323,000	1563.5	357.5
Big Cliff	Fed.	North Santiam	58.1	35	9S	4E	0	18,000	20,700	2,430	1206.0	97.0
Marion Investment	Pri.	North Santiam	28.8	11	9S	1W	0	900	900	0	NA	14.0
Stayton	Pri.	North Santiam Canal	21.0	10	9S	1W	0	600	700	0	465.0	15.0
Burnice Grewell	Pri.	Dobbins Cr.	0.5*	32	13S	3E	0	3	3	NA	NA	52.4
Green Peter	Fed.	Middle Santiam	5.7	10	13S	2E	0	80,000	92,000	333,000	1010.0	300.0
Foster	Fed.	South Santiam	37.7	27	13S	1E	0	20,000	23,000	33,600	640.0	113.0
John Wills	Pri.	Wiley Cr.	0.6	27	13S	1E	0	36	36	NA	NA	30.5
Lebanon	Pri.	S. Santiam Canal	16.0*	11	12S	2W	0	144	100	0	363.0*	10.0
Crown Zellerbach	Pri.	S. Santiam Canal	15.0*	11	12S	2W	614	0	0	0	NA	9.0
Willamette Paper	Pri.	S. Santiam Canal	14.5*	2	12S	2W	0	192	192	0	NA	10.0
Albany	Pri.	S. Santiam Canal	1.5	6	11S	3W	0	800	500	0	NA	36.0
Rolla Shelton	Pri.	Thomas Cr.	18.0	8	10S	1E	0	15	15	NA	NA	25.0
Aumsville Mill	Pri.	Mill Cr.	17.0*	31	8S	1W	76	0	0	0	NA	11.0
Mill Creek	Pri.	Mill Cr.	0.2*	22	7S	3W	15	0	0	0	NA	6.0
Columbia Paper	Pri.	Mill Cr.	0.1*	22	7S	3W	825	0	0	0	NA	18.2
Coffee Lake	Pri.	Coffee Lake Cr.	1.0*	23	4S	3W	0	12	12	Pondage	NA	20.0
Norma Holman	Pri.	Molalla	18.3	2	5S	2E	17	0	0	0	NA	5.0
Subtotal							1,752	220,808	253,264	692,030		
Lower Willamette Subarea												
Gladys Dallas	Pri.	Parrot & Beaver Crs.	1.0*	23	3S	1E	25	0	0	0	NA	25.0
Sullivan	Pri.	Willamette	26.6	31	2S	2E	0	15,400	15,000	0	54.0	40.0
West Linn	Pri.	Willamette	26.6	31	2S	2E	18,640	13,900	13,900	0	54.0	40.0
Oregon City	Pri.	Willamette	26.6	31	2S	2E	16,000	1,500	1,800	0	54.0	40.0
Timothy Meadows**	Pri.	Oak Grove Fk.	15.8	26	5S	8E	0	0	0	61,740	3190.0	95.0
Oak Grove	Pri.	Clackamas	47.6	22	5S	6E	0	51,000	49,000	546	1988.0	879.0
North Fork	Pri.	Clackamas	30.1	11	4S	4E	0	38,400	54,000	5,994	665.0	134.8
Faraday	Pri.	Clackamas	26.2	33	3S	4E	0	34,450	44,000	550	520.0	133.0
River Mill	Pri.	Clackamas	23.3	20	3S	4E	0	19,050	23,000	770	388.8	82.0
Lake Oswego	Pri.	Oswego Cr.	0.6*	10	2S	1E	0	522	522	Pondage	100.0	90.0
Machinery Sales	Pri.	Bridal Veil Cr.	0.3*	22	1N	5E	157	0	0	0	NA	865.6
Eclus Pollock	Pri.	Bowman Cr.	0.1*	5	2S	5E	0	6	6	0	NA	50.0
Bull Run	Pri.	Bull Run	1.5	6	2S	5E	0	21,000	22,000	970	657.0	326.0
Subtotal							34,822	195,228	223,228	70,570		
TOTAL							36,594	717,568	831,944	1,515,958		

* Approximate.
** Power storage used through all Clackamas River plants.
NA Not Available.

Table II-3
Developed Thermal Power Plants
December 31, 1968

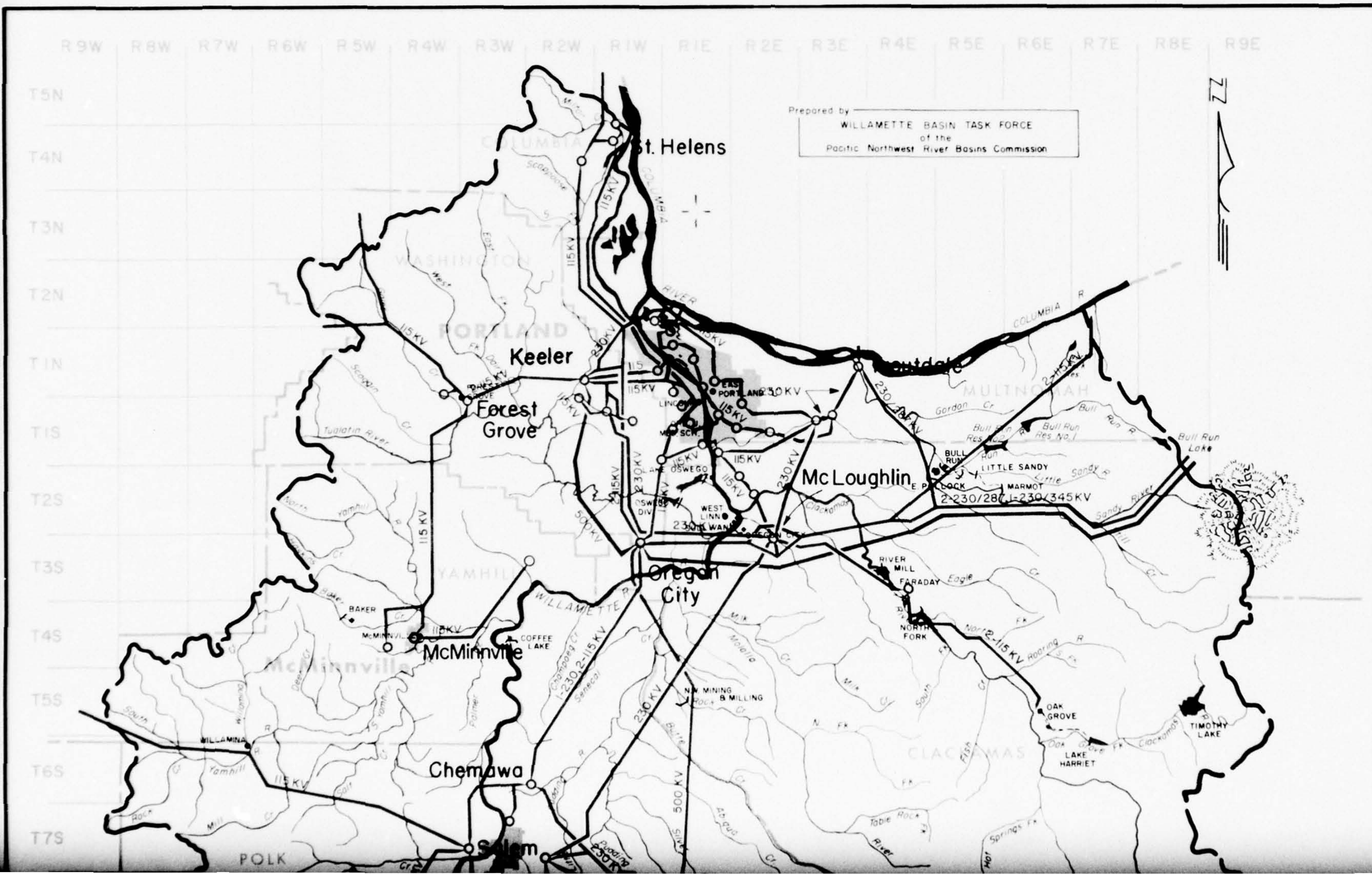
Plant	Ownership	Location* Stream Basin	Stream Mile	Sec.	T.	R.	Installed Capacity (KW)	Peaking Capability (KW)	Type**
Upper Willamette Subarea									
Oakridge	Pope & Talbot	M.Fk.Willamette	229.3	15	21S	3E	4,500	4,500	S
Cottage Grove	Weyerhaeuser	Coast Fk.Willamette	22.2	28	20S	3W	6,500	6,500	S
Springfield	Rosboro Lbr.	M.Fk.Willamette	185.0	35	17S	3W	1,500	1,500	S
Springfield	Weyerhaeuser	M.Fk.Willamette	185.0	35	17S	3W	25,000	25,000	S
Springfield	Springfield Plywd.	M.Fk.Willamette	185.0	35	17S	3W	2,250	2,250	S
Springfield	Pacific Pwr.& Light	M.Fk.Willamette	185.0	35	17S	3W	5,000	5,000	S
Eugene	Giustina Bros.	M.Fk.Willamette	182.0	32	17S	3W	2,000	2,000	S
Oregon University		M.Fk.Willamette	182.0	32	17S	3W	5,500	5,500	S
Eugene	City of Eugene	M.Fk.Willamette	182.0	32	17S	3W	26,875	26,875	S
Vaughn	Long Bell Lbr.	Noti Cr.	4.2	8	18S	6W	3,000	3,000	S
Subtotal							(10)82,125	(10)82,125	
Middle Willamette Subarea									
Albany	Simpson Lumber Co.	Willamette	119.0	5	11S	3W	3,500	3,500	S
Foster	Columbia Forest Prod.	Wiley Cr.	1.0	27	13S	1E	4,000	4,000	S
Sweet Home	Columbia Forest Prod.	South Santiam	33.5	31	13S	1E	3,000	3,000	S
Lebanon	Cascade Plywood	South Santiam	19.0	11	12S	2W	2,000	2,000	S
Lebanon	Cascade Plywood	South Santiam	19.0	11	12S	2W	1,500	1,500	IC
Dallas	Columbia Forest Prod.	Rickreall	13.7	33	7S	5W	5,250	5,250	S
Willamina	U.S. Plywood	South Yamhill	42.7	6	6S	6W	2,000	2,000	S
McMinnville	City of McMinnville	South Yamhill	5.6	28	4S	4W	2,740	2,740	IC
Subtotal							(8) 23,990	(8) 23,990	
Lower Willamette Subarea									
Forest Grove	Stimson Lbr.	Gales Cr.	2.4	6	1S	3W	1,600	1,600	S
West Linn	Crown Zellerbach	Willamette	26.6	31	2S	2E	1,225	1,225	S
Oregon University	Medical School	Willamette	14.0	4	1S	1E	440	440	S-IC
Lincoln	Pacific Pw.&Light	Willamette	13.4	3	1S	1E	35,500	47,000	S
Portland "L"	Portland Gen. Elec.	Willamette	13.3	3	1S	1E	75,500	72,300	S
Subtotal							(5) 114,265	(5) 122,565	
Willamette Basin Total							(23) 220,380	(23)228,680	

*Approximate ** S - Steam; IC - Internal Combustion

TRANSMISSION OF POWER

A number of electric utilities, both private and public, distribute power in the Willamette Basin. Six cities are served by municipal systems: Forest Grove, Canby, McMinnville, Monmouth, Eugene, and Springfield. Salem is served by Portland General Electric Company and a cooperative, Salem Electric. Portland is served jointly by two private utilities, Portland General Electric Company and Pacific Power and Light Company. Portland General Electric also serves most of the rest of the Lower Subarea of the basin. Pacific Power and Light serves much of the more intensively developed portions of the Upper and Middle Subareas. Lane County and Blachly-Lane County Cooperatives serve rural areas in the upper basin. Consumers Power Company, a cooperative, serves rural areas in the Middle Subarea. In addition, West Oregon Electric Co-op serves a small area on the western edge of the lower basin.

The Willamette Basin transmission system is an integral part of the Pacific Northwest interconnected regional transmission grid. The degree of integration is illustrated on Map IV-3, which shows the high voltage grid as of January 1970 in green and a projected system for possible development by 1990 in red. Generating facilities in the Willamette Basin are interconnected with those throughout the Pacific Northwest by this regional transmission grid. This vast network permits PGE to import power from its plants in the Deschutes River Basin. Pacific Power and Light is able to import power from its Lewis River generating complex to the north of Willamette Basin and its Umpqua River generating plants to the south. Major BPA lines traversing the basin transmit power from powerplants throughout the Pacific Northwest to the Portland, Salem, and Eugene load centers. The exchange of power through these transmission facilities also permits the use of Willamette Basin power anywhere in the Pacific Northwest. However, power requirements in the basin normally preclude the use of basin resources to serve out-of-basin power markets. Major Willamette Basin transmission facilities as of December 31, 1968, are shown on Map II-3.


Prepared by
WILLAMETTE BASIN TASK FORCE
of the
Pacific Northwest River Basins Commission
St. Helens
Keeler
Forest Grove
McLoughlin
Oregon City
McMinnville
Chemawa
Salem
PORTLAND
WASHINGTON
COLUMBIA
MULTNOMAH
CLACKAMAS
YAMHILL
POLK
2-230/287,1-230/345KV
1-230,2-115KV
2-115KV
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McMinnville
Chemawa
Salem
Albany
Fry
Santiam
Detroit
Diamond Hill
J.P. Alvey
Cottage Grove
YAMHILL
CLACKAMAS
MARION
POLK
LINN
BENTON
LANE
RIVER MILL
FARADAY
NORTH FORK
OAK GROVE
LAKE HARRIET
TIMOTHY LAKE
BAKER
COFFEE LAKE
NW MINING & MILLING
WILLAMINA
DALLES
STAYTON
MARION INVESTMENT
ROLLY SHELTON
BIG CLIFF
DETROIT
MINERAL SPRINGS
BREITENBUSH HOT SPRINGS
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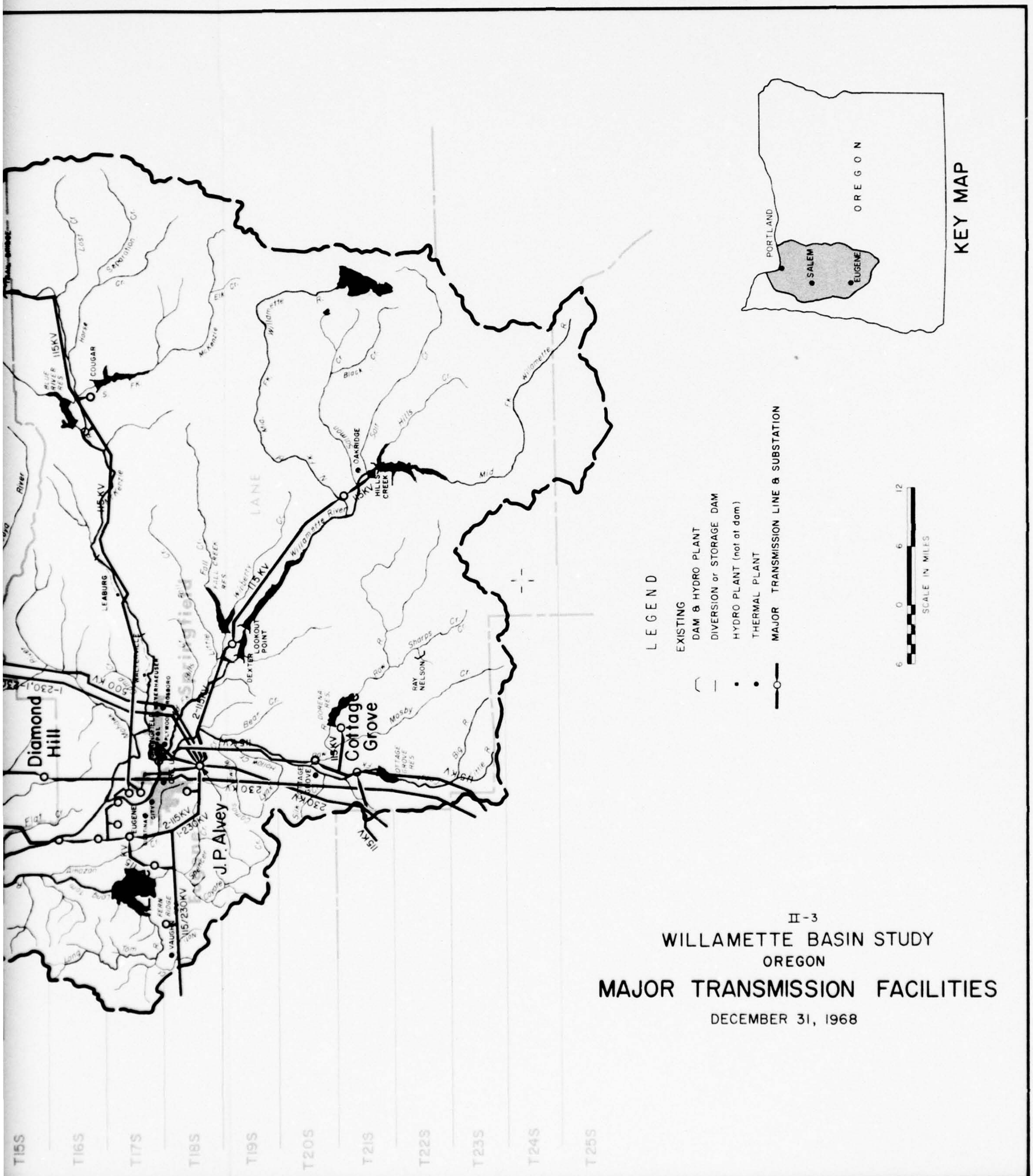
EUGENE
WEYERHAEUSER
ROSBORO
FERN RIDGE
VAUGHN
DEXTER
LOOKOUT POINT
FALL CREEK RES.
DORENA RES.
OAKRIDGE
HILLS CREEK
WILLAMETTE
500 KV
230 KV
115 KV
2-230/287 KV
1-230,1-230/287 KV
1-230,2-115 KV
2-115 KV
115/230 KV
230 KV CONST.
115 KV OPER.



II-3
WILLAMETTE BASIN STUDY
OREGON
MAJOR TRANSMISSION FACILITIES
DECEMBER 31, 1968

WBTF – 0 – 1176 – LL

3

P R O B L E M S

The largest portion of electric power used in the Willamette Basin is imported from the generating complex of the Pacific Northwest via the area electric power transmission grid. Present power requirements of the basin are being met adequately. Rights-of-way for transmission lines to bring the necessary amounts of electric power into the basin are becoming crowded. Planners for new lines seek routes to avoid wilderness areas, recognize restrictions for recreation and other competing land uses and consider alternatives to new rights-of-way through highly developed areas where the most power is actually used.

The principal problems in hydroelectric power generation result from conflicting requirements on reservoir storage for non-power purposes. Increasing demands for recreational areas have developed conflicts with prior planned conservation releases from multipurpose reservoirs. At the present, reservoir releases for flood control, irrigation, fisheries, and water quality usually can be effectively used for power generation but conflict with recreational uses of the reservoir. However, during the winter when storage levels must be held down to provide flood control space, power generation is reduced due to the lower head. One of the major needs of the area is for the development of additional multipurpose storage and the equitable allocation of its uses to the various needs. Each function should bear project costs proportionate to benefits derived.

Photo II-2. Recreation on a Storage Reservoir (USBPA Photo).

SPECIAL RESERVOIR RELEASES

Water quality--or more specifically, dissolved-oxygen content--in the Portland Harbor reach of the Willamette River has become critical on several occasions. In this reach, where water pollution is severe even under normal conditions, the problem becomes intensified during periods of low flow and higher-than-normal temperatures. Since 1965, when the problem became most acute, a number of measures have been taken which have lessened the severity of the water pollution problem.

In 1965, special releases from storage reservoirs were made by the Corps of Engineers for streamflow augmentation at the request of water pollution control officials. Also, water releases were made by Portland General Electric Company from their upstream storage. Energy losses as a result of the Company's storage releases were replaced by BPA. This shows the vulnerability of power storage in emergency situations. When power storage is also critical, any decision to use the stored water for pollution abatement instead would be even more difficult than in the 1965 situation.

Since that time aeration devices have been installed by Portland General Electric in seven draft tubes at the T. W. Sullivan plant at Willamette Falls. Also, Crown Zellerbach Corporation and Publishers Paper Company installed aeration devices in their powerplants at Willamette Falls in 1968.

The Corps of Engineers has agreed upon request to release water stored in their Willamette Basin reservoirs when emergency conditions dictate. The Corps of Engineers has, however, emphasized that there is no legal authority to meet stream pollution abatement needs at the expense of authorized project functions. They have also emphasized that streamflow augmentation should not be considered a substitute for adequate water treatment, and that such releases are subject to agreement by affected Federal agencies, in this case, Bonneville Power Administration.

POWER LINE RIGHTS-OF-WAY

It is necessary to use some land for powerline occupancy. About 20,000 acres of agricultural and forest lands in the basin are now used for powerline rights-of-way. However, this land is shared by agricultural, recreational, and wildlife uses.

The agricultural use of much of the land is continued even after a transmission corridor is put through. Row crops can still be grown, and cattle can be grazed on the rights-of-way unused by structures. On the other hand, forest areas must usually be removed from timber-growing uses, because trees would interfere with the lines; Christmas tree plantings are in exception to this, although they probably do not occupy a sizable portion of the total right-of-way. Fire control is frequently enhanced by access roads and the corridor serving as a fire break.

To determine the highest use of forest land, its utility for transporting electrical energy must be weighed against its use for other purposes.

Transmission lines may traverse and adversely affect areas of recreational value. Their visual impact must be considered in land use planning. Location of the rights-of-way when coordinated with recreation values gives an optimum balance in land use. The need for powerline rights-of-way continues to remove land from commercial forest. While it is necessary to use forest lands for this purpose, transmission planners should avoid the most productive sites whenever possible by coordination with forest land managers.

Major transmission line rights-of-way are customarily seeded to provide forage for wildlife or domestic animals if not used for agriculture or other purposes.

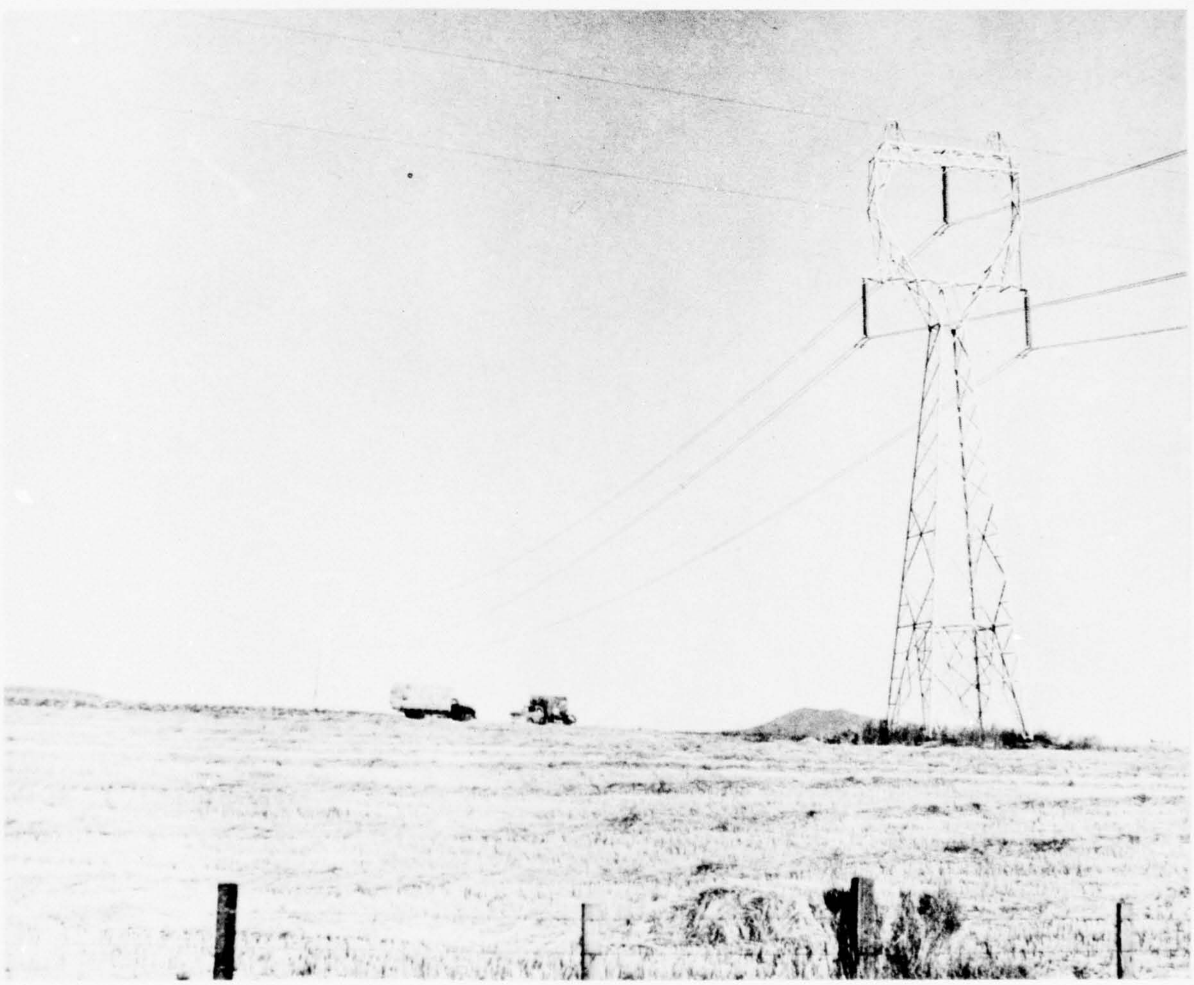


Photo II-3. Farming Under 500-KV Transmission Line (USBPA Photo).

FUTURE DEMANDS

Photo III-1. Sprinkler Irrigation (USBPA Photo).

ELECTRIC POWER REQUIREMENTS

Electric power requirements of Willamette Basin are expected to continue the rapid growth of the past. The combination of mild climate, abundant water, and plentiful agricultural and forest resources should encourage continued commercial and industrial expansion and support concurrent increases in population. The area supports a high standard of living. Use of power per customer ranks among the highest in the nation. Under such circumstances, a steady increase in the need for electric power can be expected.

SHORT-RANGE PROJECTIONS

Electric energy sales in the Willamette Basin increased by 39 percent during the 1960-65 period. This growth reflects both increases in number of customers and increased consumption per customer. These upward trends are expected to continue to 1975. Table III-1 summarizes actual energy sales in 1960 and 1965 and forecasts requirements for 1970 and 1975 by class of customer; detailed forecasts beyond the ten-year period were not considered sufficiently valid to be included in this tabulation. The factors which have and will influence energy sales are summarized later by customer groups.

Table III-1
Electric Energy Sales for 1960 and 1965, and Estimated Requirements for 1970 and 1975, Willamette Basin

	Actual		Estimated	
	1960	1965	1970	1975
Population	1,168,899	1,338,900	1,450,500	1,648,800
No. persons per:				
Domestic Customer	3.32	3.30	3.00	2.95
Commercial Customer	25.7	25.5	22.5	21.5
No. Customers				
Domestic	352,207	405,091	483,500	558,920
Commercial	45,571	52,395	64,470	76,690
Average KWH/Customer				
Domestic	10,107	11,852	14,000	16,500
Commercial	35,130	45,514	55,000	65,000
Energy Sales (Millions of KWH)				
Domestic	3,563	4,801	6,769	9,222
Irrigation	20	54	85	120
Commercial	1,601	2,385	3,546	4,985
Industrial	3,636	5,040	7,969	11,282
Miscellaneous	161	219	297	387
Total	8,981	12,499	18,666	25,996
% Losses	9.6	8.2	8.0	8.0
Energy Requirements (Millions of KWH)	9,934	13,618	20,289	28,256
December Peak (MW)	1,817	2,655	3,952	5,670

The values shown in Table III-1 for 1970 and 1975 are based on projections made by utilities serving the area and reflect their assessment of potential growth.

DOMESTIC

The number of domestic electric customers (farms, homes, and seasonal cabins) has increased more rapidly than the population. Factors contributing to this growth have been the wave of World War II babies reaching marriageable age, smaller families, and the establishment of second homes by a larger number of more affluent families. These factors will probably continue to increase the number of domestic customers at a more rapid rate than population growth.

Average use per domestic customer, adjusted for exceptional weather conditions, increased about 400 kwh per year from 1960 to 1965. During that period, electric space heating in the Willamette Basin increased from about 12 percent of the homes to almost 23 percent, accounting for three-fourths of the total increase. Further increases in domestic use of about 400 kwh per year can be expected through 1970. Slightly higher increases are forecast from 1970 through 1975, based on the growing demand for all-year air conditioning.

IRRIGATION

Energy sales for irrigation by 1975 will be more than double the 1965 level. Sprinklers are used on about 95 percent of the land now under irrigation. Future growth will rely primarily on the use of sprinklers. By the year 1975 over 360,000 acres will be under irrigation compared to 244,000 acres in 1966.

COMMERCIAL

Commercial electric energy sales have increased as air conditioning, lighting, and electric-heating loads increased. Many shopping centers, office buildings, and small factories have been constructed in recent years to serve the expanding economy. These trends are expected to continue in the foreseeable future.

INDUSTRIAL

The Bonneville Power Administration serves four electro-process industries in the Willamette Basin: Reynolds Metals Company at Troutdale, and Pacific Carbide & Alloys Company, Pennwalt Corporation, and Union Carbide Corporation in Portland. Some of the major industrial plants served by other utilities in the basin are: Wah Chang Corporation and Oregon Metallurgical Corporation located at Albany, Weyerhaeuser Company at Springfield and Cottage Grove, Boise Cascade Corporation at St. Helens, Crown Zellerbach Corporation at West Linn, Publishers Paper Company at Oregon City and Newberg, and Oregon Steel Mills at Portland. Expansion of these and other industrial plants in the basin is expected to occur at a rate of about 8 percent per year over the next 10 years.

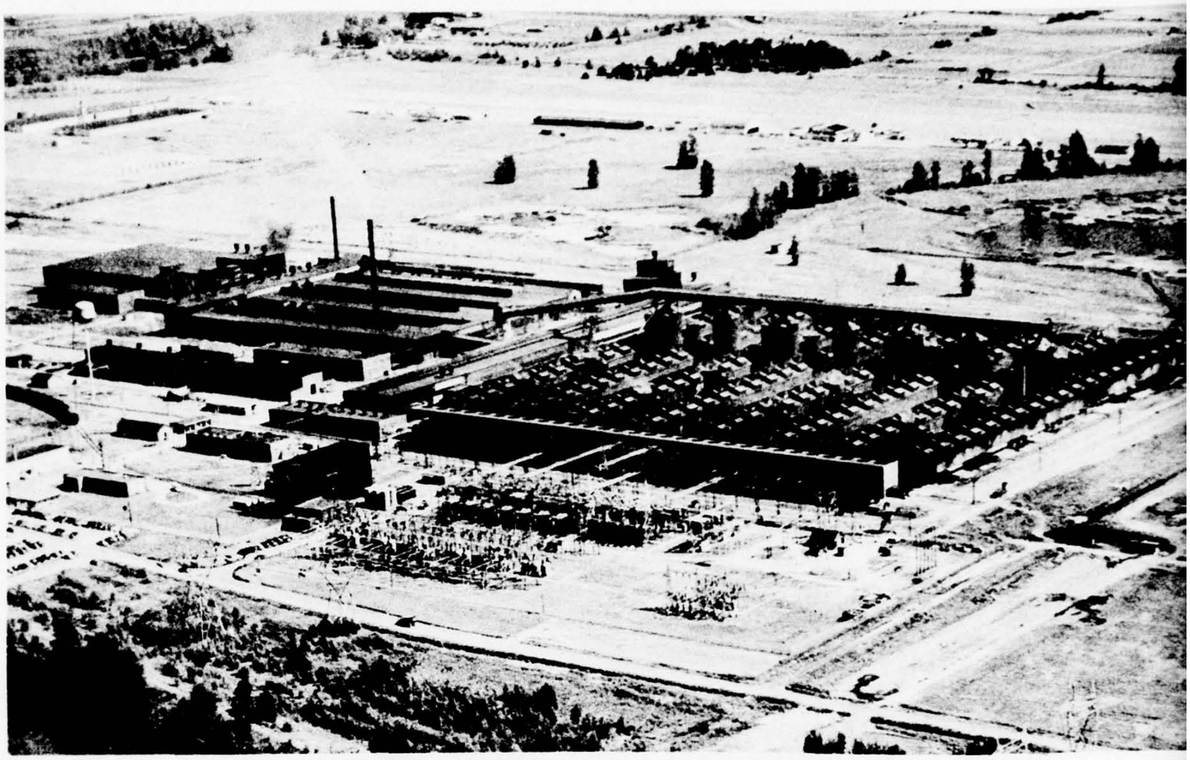


Photo III-2. Reynolds Metals Co. Plant, Troutdale (BPA Photo).

MISCELLANEOUS

Sales which do not fall under domestic, commercial, irrigation, or industrial headings are classified as miscellaneous. Sales to Federal agencies or public authorities are classed under this heading, for example. Growth in this group is expected to parallel that of other types of use.

LONG-RANGE PROJECTIONS

The long-range (1975-2020) trend in electric power demands in the basin will likely continue upward at about the same rate experienced in years past. This estimate is based largely on confidence in future expansion of the economy, and hence the need for electric power. The basin's growth is expected to advance at a somewhat higher rate than for the region as a whole. Regional wholesale electric power costs will continue at lower than national average costs providing an inducement to further load growth. Future power requirements, in part, will be supplied from higher cost thermal generation compelling a gradual increase in power rates. However, the blending of hydroelectric power generation with thermal generation will result in a continuing lower local average wholesale power cost as compared with the national average. This will be reflected in lower resale rates in the region compared with the nation as has been the historic trend. Load forecasts are based on the accumulation of utility loads and potential large electro-process industrial power requirements in the basin. Table III-2 shows energy requirements, peak demands, and annual load factors estimated for each fifth year of the period 1975-2020.

Table III-2
Estimated Electric Power Loads, Willamette Basin

Year	Energy (Millions of KWH)	Demand (1,000 KW)	Annual Load Factor-%
1975	28,256	5,670	56.8
1980	38,400	7,730	56.7
1985	52,900	10,600	57.0
1990	72,700	14,600	56.8
1995	99,700	20,000	56.8
2000	136,000	27,300	56.8
2005	185,000	37,200	56.8
2010	250,000	50,200	56.8
2015	338,000	67,900	56.8
2020	457,000	91,800	56.8

Figure III-1 shows actual and forecast peak loads, the existing resources, and capacity required from other sources.

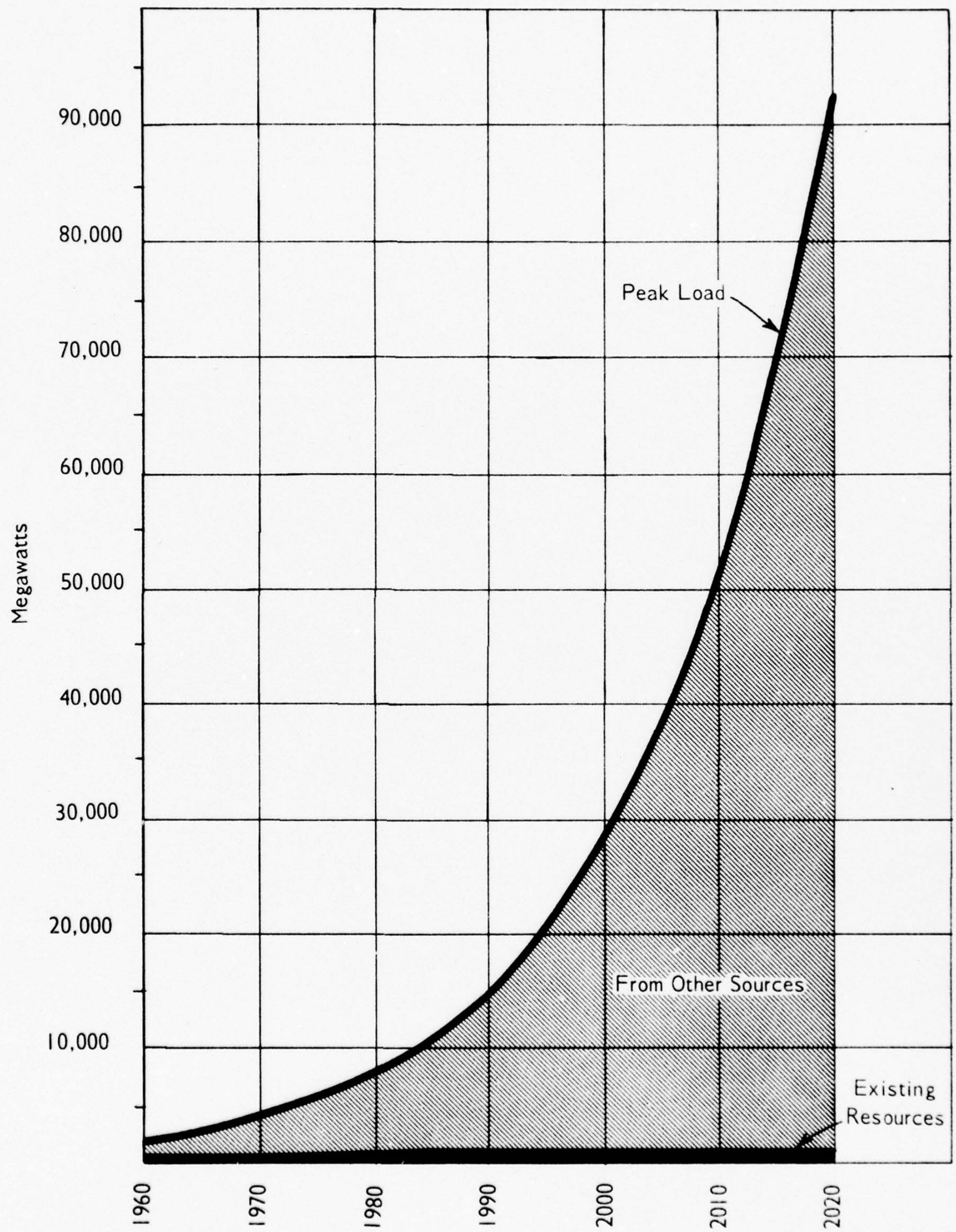


Figure III-1 - *Peak Load and Peak Generating Capacity*

ALTERNATIVE MEANS TO SATISFY DEMANDS

The dramatic increase in electric power requirements projected in Part III - Future Demands requires immediate attention from all planners. A pivotal point has been reached in the power industry of the Pacific Northwest. Most of the economic hydroelectric energy will soon be developed. The few large undeveloped sites which still remain lie outside the Willamette Basin. Consequently, Northwest utilities, including those serving the basin, must look to other sources of power to supply their future needs.

To meet the peak demand by 2020, Willamette Basin will need over 90,000,000 kilowatts, about 90 times the basin's present generating capacity. The potential hydroelectric projects in the basin could not begin to satisfy the power needs. Large thermal plants will likely be built to meet energy loads in the basin. Considerable power must be provided from other sources to supply reserves for outages and additional peak needs. Some of this will be imported.

The only potential hydroelectric development in the basin which has progressed beyond the preliminary stage is the authorized expansion of the existing Cougar project. This includes adding 35,000 kilowatts at site and building the Strube reregulating dam downstream with 4,500 kilowatts of installed capacity. No work has been initiated on this project.

Photo IV-1. Cougar Dam (USCE Photo).

Hydroelectric facilities could be installed at a number of potential multipurpose dams in the basin. Preliminary studies identify 18 sites plus four alternative sites. If all 18 were developed to include hydroelectric power, these projects would add over 550,000 kilowatts to the area power supply. Also, six potential single-purpose hydroelectric power projects could be developed to add 210,000 kilowatts.

Other possible sources of additional hydroelectric capacity would be pumped-storage projects. Numerous pumped-storage sites could be developed in the Willamette Basin. Initially, the 43 largest of these installations could produce an aggregate 44,000,000 kilowatts and ultimately, about 128,000,000 kilowatts. Potential "conventional" hydroelectric sites and pumped-storage projects are shown on Map IV-1.

Increased importation of power from outside the basin will be another source of power supply. This will require the building of additional extra-high-voltage transmission lines into the basin.

The alternative means of obtaining future electric power for the basin, costs, and associated problems are presented herein.

POWER RESOURCES

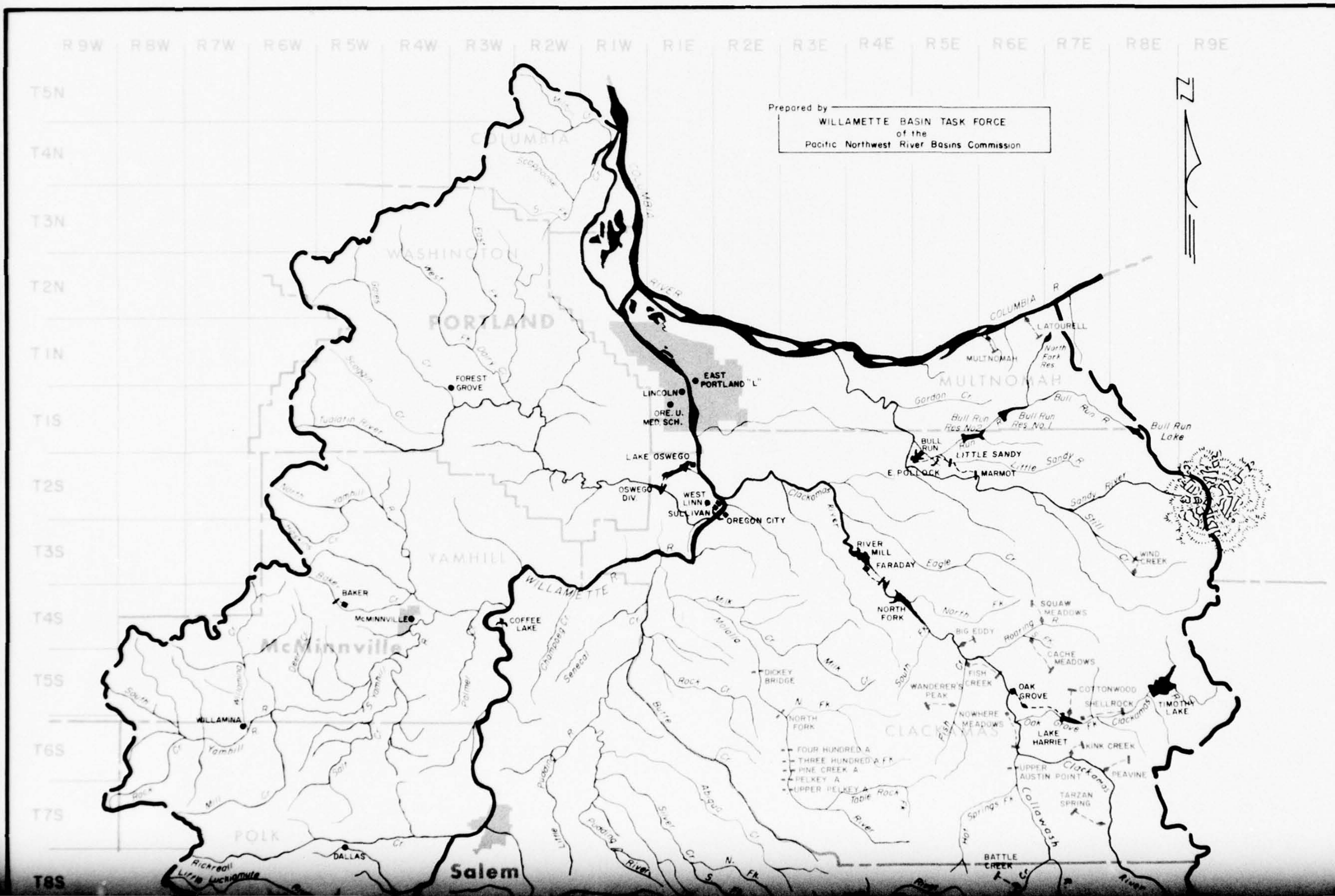
In the studies of power resources for the Willamette Basin, several methods of producing power were examined. The limited potential hydroelectric resources were found inadequate to supply all the power requirements of the basin. The possible sources of power for the basin--hydroelectric, fossil-fuel electric, nuclear-electric, and importation of power--are discussed in the sections following.

The criteria used to determine hydroelectric power values are presented in Addendum "A." These data are used to determine the comparative benefits of power produced by "conventional" hydroelectric plants.

"CONVENTIONAL" HYDROELECTRIC PLANTS

Possible sites for development of "conventional" hydroelectric resources within the Willamette Basin fall into two categories. The first includes hydroelectric power plants at potential multiple-purpose reservoir sites. The second includes only potential single-purpose hydroelectric projects. These sites are not to be confused with the potential pumped-storage plants discussed later.

Within the Willamette Basin, generation could be installed at 18 potential multiple-purpose reservoir sites, having an estimated total installation of about 550,000 kilowatts. In all, there are 22 project sites (Table IV-1) with possible economic feasibility as additions to potential multiple-purpose projects. However, several sites are mutually exclusive. Further investigation of the 22 potential sites is warranted only if the associated dams and reservoirs should be proposed for other purposes. Five sites on the Molalla River--Pine Creek, Pelkey, Upper Pelkey, Three Hundred, and Four Hundred--are in the same general location, and are alternatives to each other.



Prepared by
WILLAMETTE BASIN TASK FORCE
of the
Pacific Northwest River Basins Commission
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FARADAY
NORTH FORK
WIND CREEK
SQUAW MEADOWS
BIG EDDY
CACHE MEADOWS
FISH CREEK
WANDERER'S PEAK
OAK GROVE
COTTONWOOD
SHELLROCK
TIMOTHY LAKE
NOWHERE MEADOWS
LAKE HARRIET
KINK CREEK
UPPER AUSTIN POINT
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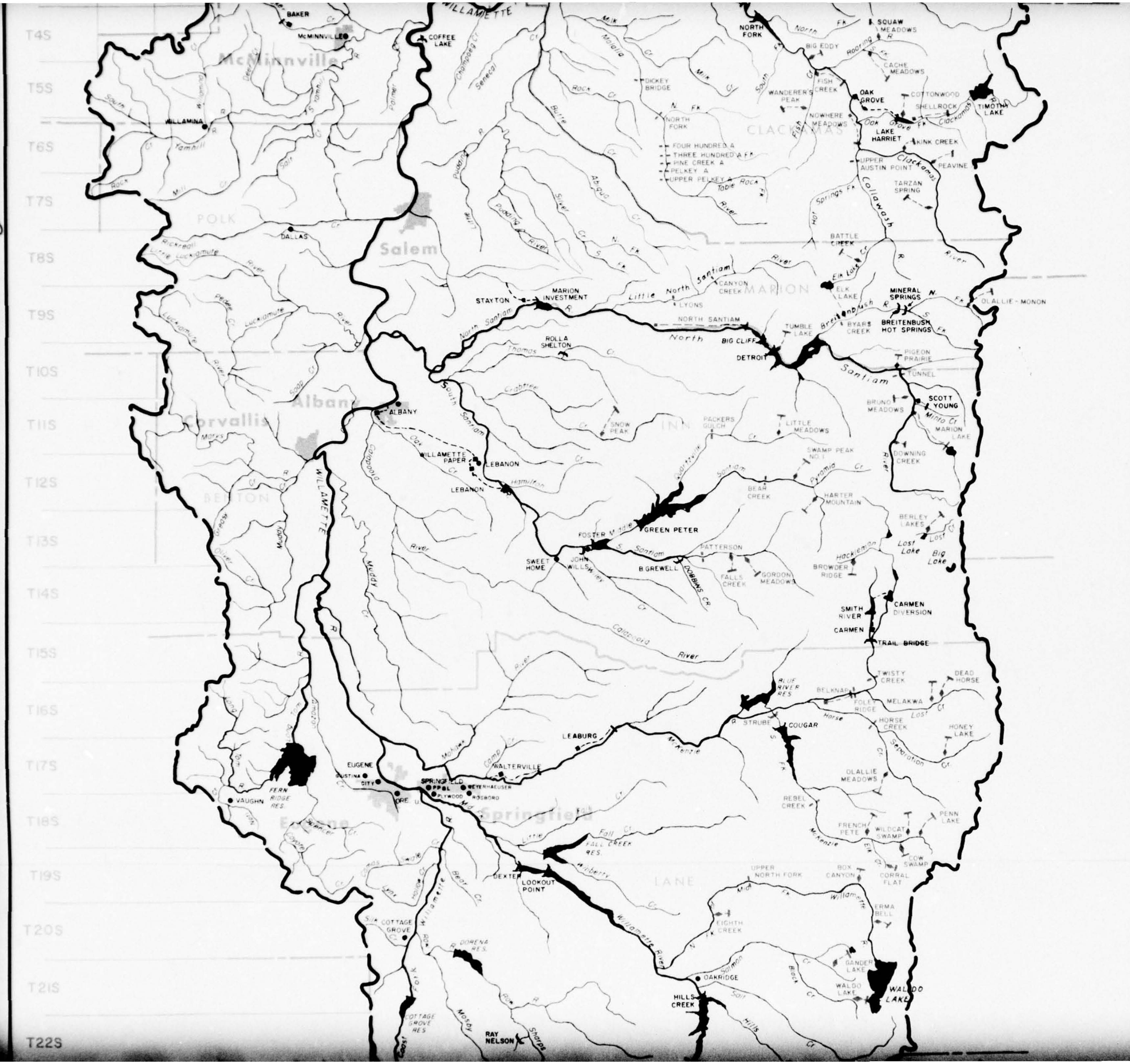
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MINERAL SPRINGS
OLALLIE - MONON
BREITENBUSH HOT SPRINGS
BYARS CREEK
TUMBLE LAKE
CANYON CREEK
LYONS
STAYTON
MARION INVESTMENT
NORTH SANTIAM
BIG CLIFF
DETROIT
PIGEON PRAIRIE
TUNNEL
SCOTT YOUNG
BRUNO MEADOWS
MARION LAKE
DOWNING CREEK
ROLLA SHELTON
SNOW PEAK
PACKERS GULCH
LITTLE MEADOWS
SWAMP PEAK NO. 1
BEAR CREEK
HARTER MOUNTAIN
ALBANY
WILLAMETTE PAPER
LEBANON
GREEN PETER
FOSTER
SWEET HOME
JOHN WILLS
PATTERSON
B GREWELL
DOBBINS CR
FALLS CREEK
GORDON MEADOWS
BERLEY LAKES
Lost Lake
Big Lake
BROWDER RIDGE
CARMEN DIVERSION
SMITH RIVER
CARMEN
TRAIL BRIDGE
TWISTY CREEK
DEAD HORSE
BLUE RIVER RES
BELKNAP
FOLEY RIDGE
MELAKWA
HORSE CREEK
HONEY LAKE
STRUBE
COUGAR
LEABURG
WALTERVILLE
EUGENE
GUSTINA
CITY
ORE
SPRINGFIELD
PPBL
WEYERHAEUSER
PLYWOOD
ROSBORO
FERN RIDGE RES.
VAUGHN
OLALLIE MEADOWS
REBEL CREEK
PENN LAKE
FRENCH PETE
WILDCAT SWAMP
COW SWAMP
FALL CREEK RES.
DEXTER
LOOKOUT POINT
UPPER NORTH FORK
BOX CANYON
CORRAL FLAT
ERMA BELL
EIGHTH CREEK
COTTAGE GROVE
DORENA RES.
COTTAGE GROVE RES
OAKRIDGE
HILLS CREEK
GANDER LAKE
WALDO LAKE
RAY NELSON
Collawash
Clackamas
Little North Santiam
North Santiam
South Santiam
Breitenbush
Calapooia River
Muddy Cr
McKenzie
Willamette River
Mohawk
Amazon
Long Tom
Luckiamute
Yamhill
Molalla
Pudding River
Abiqua
Silver Cr
Thomas
Crabtree
Hamilton
Quartzville
Wiley
Hackleman
Separation Cr
Horse
Salmon
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Hills Cr
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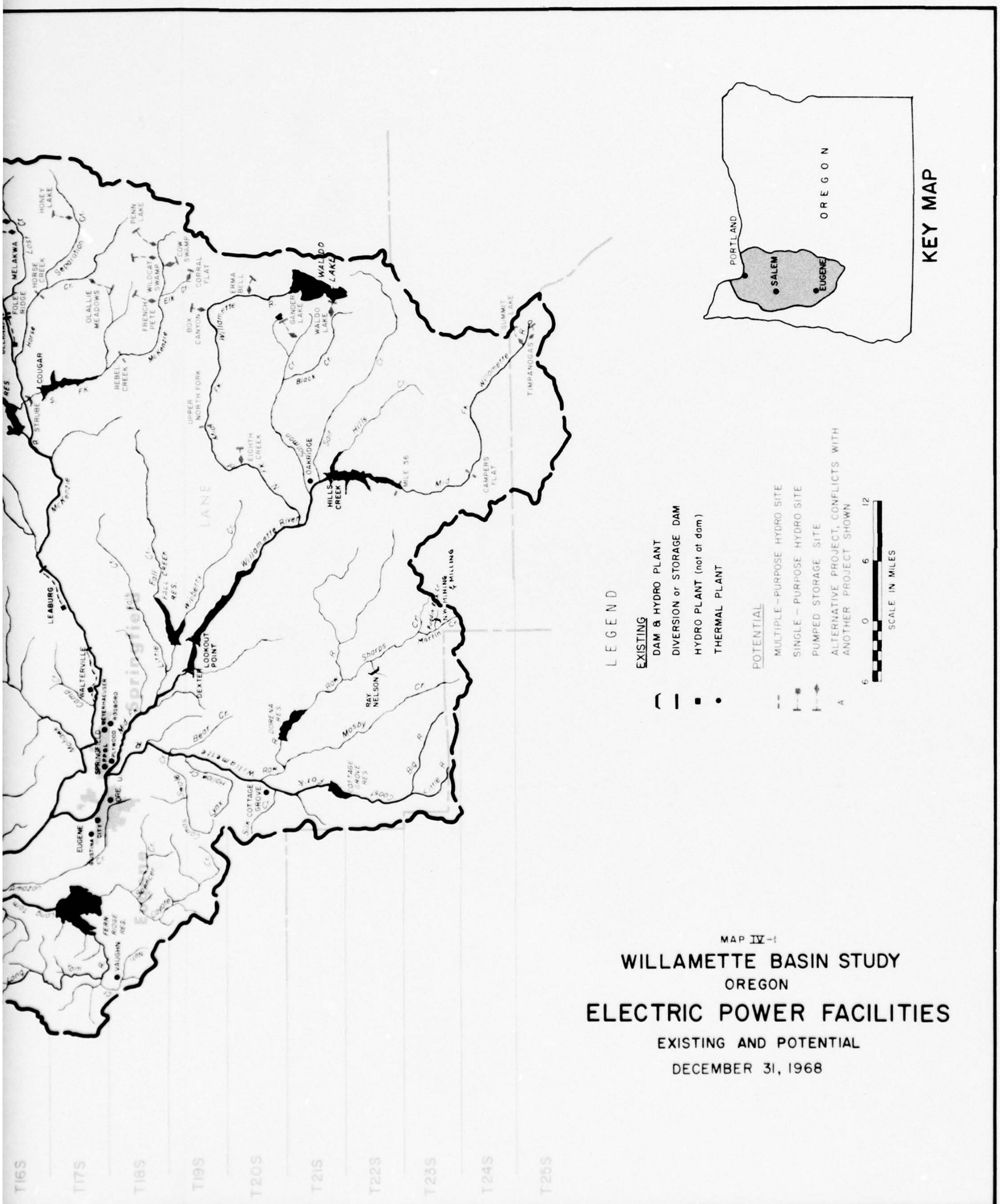
Coast Fork



MAP IV-1

WILLAMETTE BASIN STUDY

OREGON

ELECTRIC POWER FACILITIES

EXISTING AND POTENTIAL

DECEMBER 31, 1968

WBTF-0-1177-LL

The 22 potential multiple-purpose developments were selected from a list of sites being considered by Federal construction agencies. All possible developments with a potential capacity of less than 20,000 kilowatts were first eliminated from further consideration. Of those sites over 20,000 kilowatts, 22 were found to have economic feasibility.

Potential installations were evaluated by assuming an overall plant factor of 40 percent, utilizing average annual streamflow and maximum gross head with an efficiency of 83 percent. The test for economic feasibility was made for specific power facilities only (without associated dam and reservoir costs), using reconnaissance-level cost data and a dependable capacity of 80 percent of the installed capacity.

There are also six potential single-purpose hydroelectric developments in the basin, with a total installed generating capacity of 210,000 kilowatts (Table IV-2). These sites were selected from a list of potential hydroelectric developments shown in the Federal Power Commission's

Photo IV-2. Collawash River Gorge near Austin Point (USCE Photo).

Planning Status Report on the "Willamette River Basin," dated 1966, and are worthy of further investigation. The determination of economic feasibility for these potential projects is based on reconnaissance-level cost data and value-of-power criteria presented in Addendum "A."

The potential developments shown on Tables IV-1 and IV-2 have been analyzed without imposing possible restrictions for non-power uses. These restrictions should be considered in any further investigation, using refined hydrologic data and cost estimates. Also, there is a possibility that in some cases reregulation would be required. The costs and benefits in Tables IV-1 and IV-2 are developed from data prepared by the Federal Power Commission and the Corps of Engineers, North Pacific Division.

Cost estimates for potential projects are based on assumed Federal construction. The cost figures shown for "conventional" hydroelectric plants are not to be compared with those for pumped-storage projects due to differences in assumptions used. Intake costs, penstock costs, and operation and maintenance costs for the projects listed on Tables IV-1 and IV-2 were estimated from data developed by the Federal Power Commission. Powerhouse costs were determined by using curves prepared from actual costs incurred at projects in the area. This information was developed by the Corps of Engineers.

Cost estimates were based on January 1969 prices and Federal financing with interest and amortization at 4-5/8 percent over a 50-year period. The reader should recognize that prices and the interest rate to be used for a detailed feasibility analysis of any of the projects discussed in this appendix would be those pertinent to the constructing entity and financial conditions prevailing at the time. Estimates herein are intended to identify projects for possible future detailed study.

PUMPED-STORAGE PLANTS

Power resource studies indicate that in the future, a major part of the Pacific Northwest's base load will be met by nuclear powerplants. Nuclear plants supply base-load energy at a relatively low cost but they are an expensive source of peaking capacity. Therefore, more economical means for providing peaking capacity are desirable. Until about 1990, the peaking requirements of the region will probably be met by adding generating units to the existing "conventional" hydroelectric projects. When the addition of those units is completed, other sources of peaking capacity must be developed. Several alternative sources are available, including pumped-storage. Recent improvements in reversible pump-turbines have created considerable interest in pumped-storage, especially in areas where reservoir sites with high head are available, as they are in Willamette Basin.

Operation

Pumped-storage is unique among methods of hydroelectric power generation in that it depends on other electrical-power sources for its energy supply. It functions as an energy accumulator in that the

Table IV-1

Potential Multiple-Purpose Hydroelectric Projects

Site	Stream	Location Power Plant S : T : R	Maximum Gross Head (Ft)	Installed Capacity (Kw)	Avg. Annual Generation (Million Kwh)	Annual Power Benefits 1/ ($1000)	Annual Power Costs 2/ ($1000)	B/C Ratio
Middle Fork Willamette Subbasin								
Campers Flat	MF Willamette	12 24S 3E	347	24,000	85	493	424	1.16
Mile 56	MF Willamette	34 22S 3E	313	32,000	111	644	493	1.31
Upper No. Fork	NF of Middle Fk.	27 19S 4E	314	20,000	69	400	381	1.05
McKenzie River Subbasin								
Horse Creek	Horse Creek	35 16S 6E	392	31,000	107	621	490	1.27
Foley Ridge	McKenzie	9 16S 6E	290	55,000	193	1119	679	1.65
Rebel Creek	SF McKenzie	N.44°-0, W122°-10'	385	24,000	83	481	426	1.13
Twisty Creek	McKenzie	2 16S 6E	327	46,000	160	928	608	1.53
Santiam River Subbasin								
Patterson	So. Santiam	35 13S 3E	370	18,000	64	371	366	1.01
Packers Gulch	Quartzville Cr.	24 11S 3E	450	32,000	110	638	509	1.25
Lyons	Little N. Santiam	8 9S 3E	285	22,000	78	452	400	1.13
Byars Creek	Breitenbush R.	29 9S 6E	398	27,000	95	551	455	1.21
Tunnel	No. Santiam	20 10S 7E	357	32,000	111	644	499	1.29
Canyon Creek	Little N. Santiam	36 8S 3E	335	22,000	76	441	407	1.08
Bear Creek	Middle Santiam	24 12S 4E	395	25,000	86	499	436	1.14
Pudding River Subbasin								
North Fork	Molalla River	31 5S 3E	378	48,000	167	969	640	1.51
Dickey Bridge	Molalla River	14 5S 2E	229	31,000	107	621	484	1.28
Pine Creek 3/	Molalla River	31 6S 3E	374	28,000	99	574	463	1.24
Pelkey 3/	Molalla River	6 7S 3E	370	28,000	98	568	462	1.23
Upper Pelkey 3/	Molalla River	6 7S 3E	360	27,000	93	539	458	1.18
Three Hundred 3/	Molalla River	30 6S 3E	445	36,000	125	725	547	1.32
Four Hundred 3/	Molalla River	19 6S 3E	470	38,000	134	777	571	1.36
Clackamas River Subbasin								
Upper Austin Pt.	Collawash	27 6S 3E	405	38,000	132	766	552	1.39

1/ Calculated at 50 percent capacity factor and 5.8 mill value from Figure A-1.
2/ Based on 50-year project life, 4-5/8 percent interest, and only the cost of adding power to a multiple-purpose project.
3/ Conflicting locations.

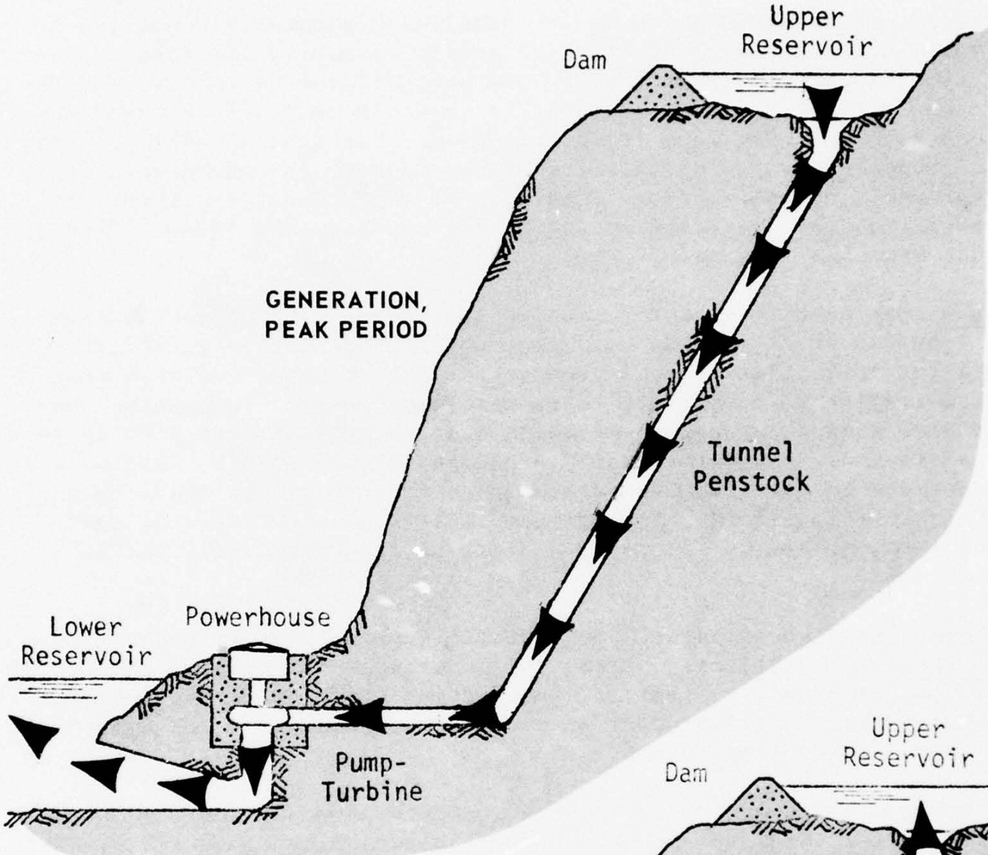
Table IV-2

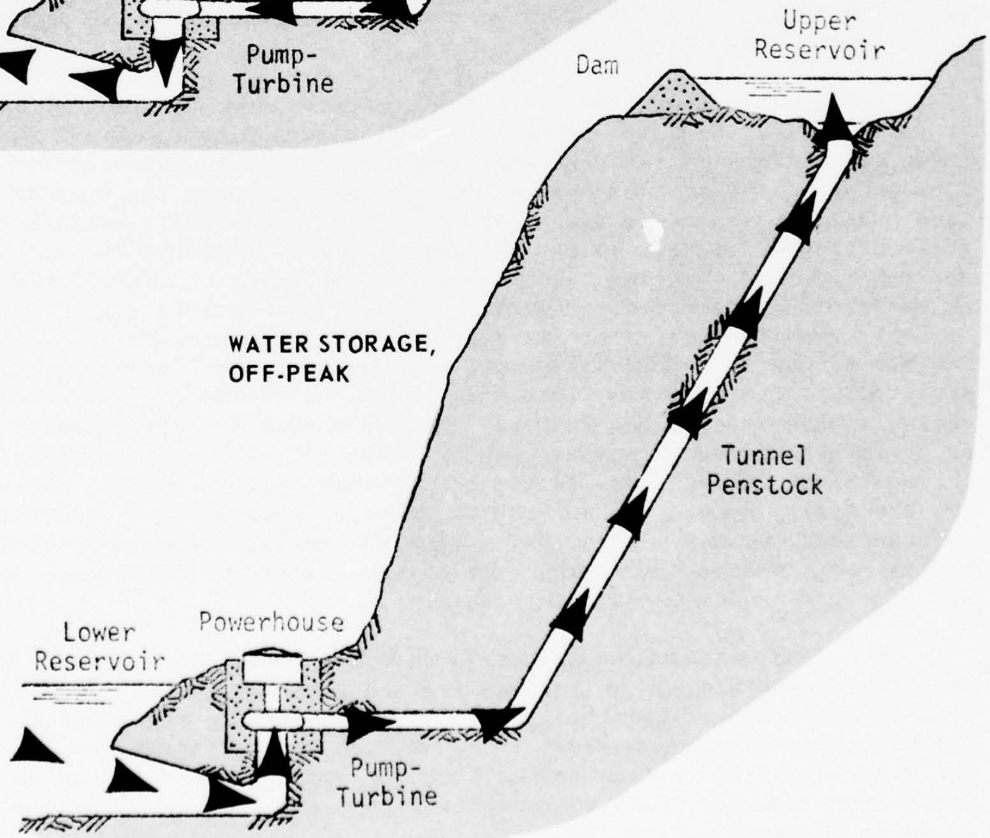
Potential Single-Purpose Hydroelectric Projects

Site	Stream	Power Plant Location S : T : R	Maximum Gross Head (Ft)	Installed Capacity (Kw)	Average Annual Generation (Million Kwh)	Annual Power Benefits 1/ ($1000)	Annual Power Costs 2/ ($1000)	B/C Ratio
McKenzie River Subbasin								
Belknap	McKenzie	13 16S 5E	385	35,000	230	1334	845	1.58
Santiam River Subbasin								
North Santiam	No. Santiam 3/	25 9S 2E	342	63,000	390	2262	1137	1.99
Marion Lake	No. Santiam	23 10S 7E	1500	22,000	154	893	460	1.94
Clackamas River Subbasin								
Fish Creek	Clackamas	1 5S 5E	240	27,000	140	812	695	1.17
Nowhere Meadows	Clackamas	34 5S 6E	240	28,000	180	1044	719	1.45
Shell Rock	Oak Grove Fk.	3 6S 7E	927	35,000	108	626	599	1.04

1/ Calculated at 50 percent capacity and 5.8 mill value from Figure A-1.
2/ Based on 50-year project life and 4-5/8 percent interest.
3/ Water supply from diversion on Marion Creek.

Figure IV-1 - Typical Pumped Storage Project





low-valued, off-peak capacity at "conventional" plants is converted to high-value capacity by using off-peak energy to pump water from a lower to a higher reservoir (Fig. IV-1). The water stored in the higher reservoir can then be returned through the turbines to generate power during peak-load periods, when it is most needed and thus has its greatest value. Pumped-storage installations offer many of the advantages of "conventional" hydroelectric plants such as rapid start-up, long life, dependability, low operating and maintenance costs, and adaptability as low-cost spinning reserve.

Low cost peaking capacity becomes increasingly important as peak loads grow and sizes of base load generating units increase, and as demands for reliability become greater. Pumped-storage can help meet this requirement at a moderate cost. As large nuclear generating complexes have sudden outages, some means must be available to pick up this lost generation. Reversible units are remarkably flexible. Not only do they generate in one direction and pump in the other, but they can be available immediately as spinning reserve if the inlet valve is open - or less than one minute if closed. Start up from standstill is within three minutes.

When operating as pumps, the reversible pump-turbines offer a double reserve capability. First, the power used for pumping can be interrupted, and second, their own generating capacity is available to meet peak loads. They also act as synchronous condensers for system power factor correction.

Pumped-storage may be designed to operate on a seasonal, weekly, or daily cycle. Seasonal pumped-storage is economical in a system where there is a period in the year when there is both surplus water and surplus energy. The surplus energy would be used to pump the surplus water into a holding reservoir to be used for generation during periods of greatest power demand. In the Willamette Basin, however, the streamflow and power-demand patterns do not appear to be favorable for seasonal pumped-storage operation. Moreover, high-head reservoir sites capable of storing sufficient water for seasonal operation are not available in the basin. Daily and weekly pumped-storage hold considerable promise, especially since thermal plants will assume an increasing share of the region's base load in the future. Thermal plants are most ideally suited to furnish off-peak pumping power. Best efficiency is obtained when thermal plant loadings are maintained at near maximum output. Generally, the energy needed for pumping is obtained from surplus generation at base-load thermal plants during low-load hours. As more thermal plants are put into operation, more off-peak energy will become available for use by pumped-storage plants.

Water can be pumped at night (and on weekends) and released during the day to generate energy for meeting the system's peak loads (Fig. IV-2). Due to inefficiencies in the operation of the pump-turbines, approximately one and one-half times as much energy is required to pump the water "uphill" as is obtained from the falling water in the generating phase. However, this increased energy use is justified by the high value of the peak generation.

Selection of Pumped-Storage Sites

In the pumped-storage studies, most of the effort was placed on locating sites suitable for large peaking plants capable of operating on a daily or weekly cycle using off-peak thermal energy. These are the sites discussed in subsequent paragraphs of this section. Some consideration was also given to seasonal storage projects capable of

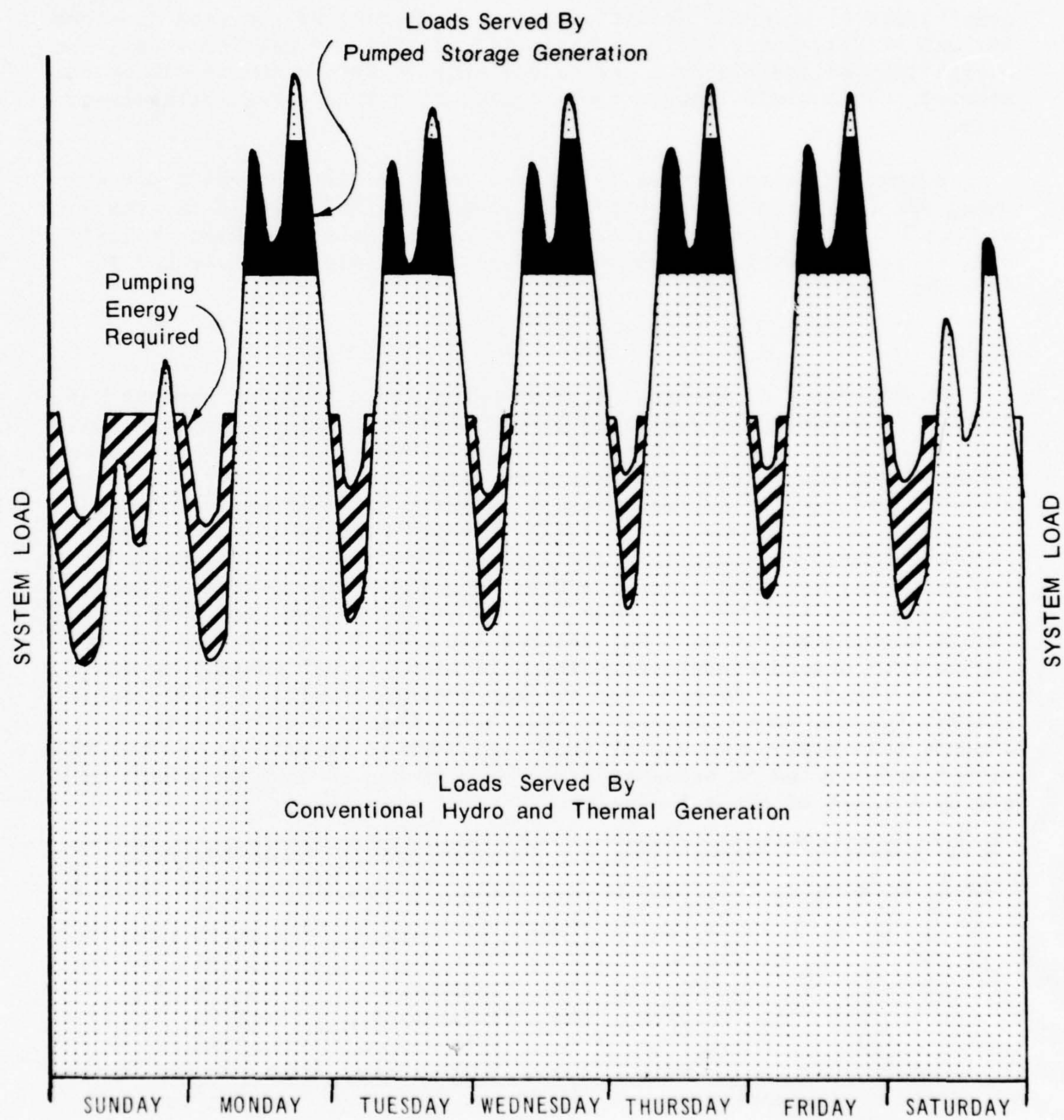


Figure IV-2 - Typical Weekly System Load Curve storing water for late-summer release for water quality enhancement as well as power generation. An example is the New Era site, which is located off-stream, a few miles above Oregon City. However, the power benefits from such a project would be incidental, and therefore similar projects would be best considered on the basis of other benefits such as pollution abatement. The possibility of installing reversible units at the existing Willamette Basin plants such as Detroit, Lookout Point, Green Peter and Cougar (projects with existing or potential reregulating reservoirs) was evaluated, and none except Cougar appeared to have any possibility of economic feasibility. At such time as the need develops for use of Willamette Basin hydroelectric plants for peaking power, the possibility of installing a reversible unit at Cougar dam should be considered. This would require construction of Strube reregulating reservoir.

Potential sites with an investment cost of less than $150 per kilowatt, and their characteristics, are summarized on Table IV-3. The locations of these sites are shown on Map IV-1. Site-selection criteria used in the evaluation of pumped-storage potentials are presented in Addendum "B."

Costs

On the basis of the cost data shown on Table IV-3, it appears that it will be possible to construct pumped-storage in the Willamette Basin having an annual cost of about $6.50 per kilowatt based on 4-5/8 percent Federal financing. Federal Power Commission studies indicate that the annual fixed cost of nuclear thermal capacity at 4-5/8 percent Federal financing is $14.26 and the variable (energy) cost is 1.27 mills per kilowatt-hour. Assuming that the peaking capacity will be required for 876 hours per year (10 percent annual capacity factor), that off-peak pumping energy will be available at 1.27 mills per KWH, and that 1-1/2 KWH of pumping energy will be required for each KWH of peaking energy, the cost of pumped-storage capacity will be $8.17 per KW-year as compared to $15.37 per KW-year for nuclear thermal capacity. Again using current Federal Power Commission cost data, the tabulation below indicates that pumped-storage at $6.50 per KW-year is more economical than either gas turbine or steam-electric peaking plants down to annual capacity factors of about 2 percent.

Annual Capacity Factor, Percent	Pumped-Storage $/KW-Year 1/	Gas Turbines $/KW-Year 2/	Steam-Electric Peaking, $/KW-Year 2/
25	10.67	-	17.14
20	9.84	-	15.20
15	9.00	-	13.21
10	8.17	17.73	11.06
5	7.34	11.24	8.75
2-1/2	6.92	7.99	7.45
1	6.67	5.96	-

1/ Based upon capacity cost of $6.50 per KW-Year and energy cost of 1.9 mills/Kwh.

2/ Based on financing comparable to that used in computing pumped-storage costs (4-5/8% over 50 years).

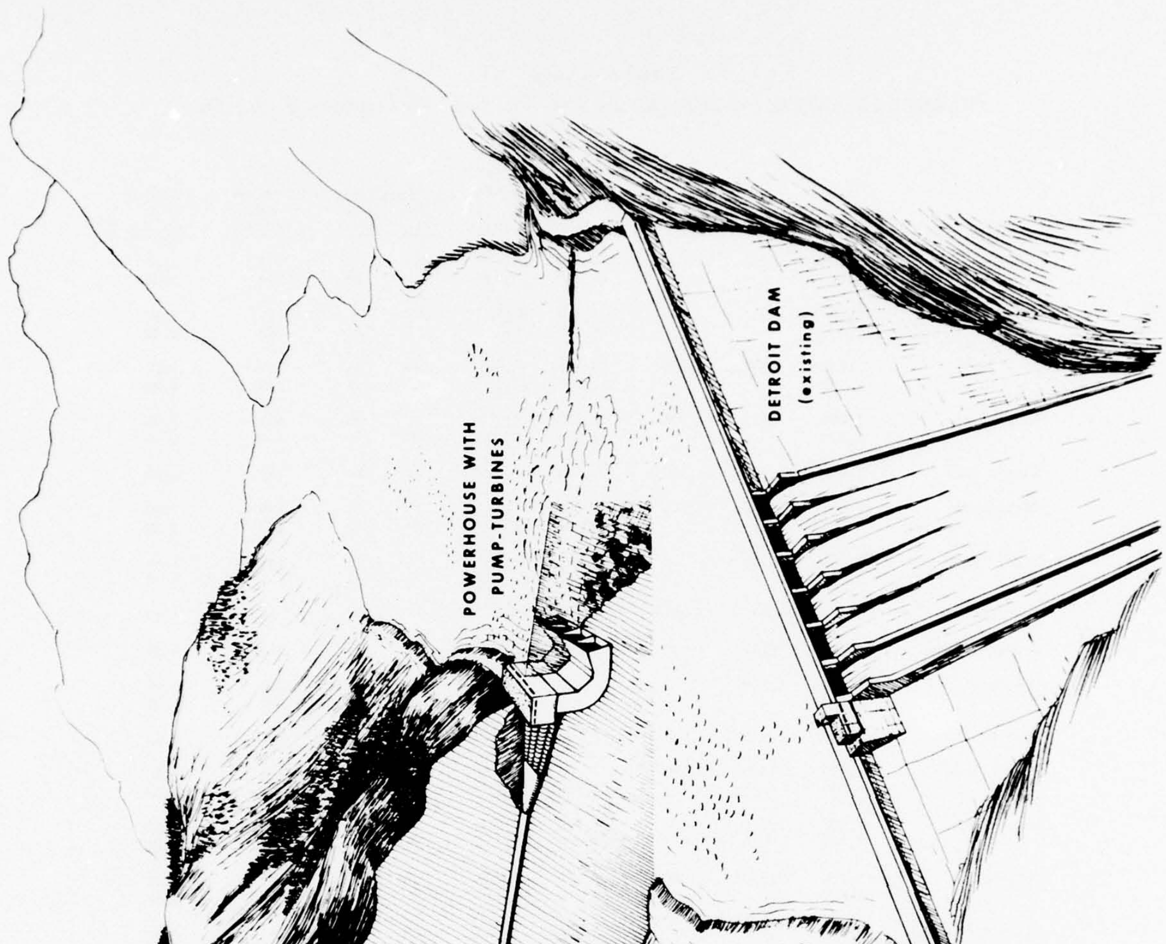


Figure IV-3. Sketch of Tumble Lake Pumped-Storage Site

Table IV-3
Potential Pumped-Storage Sites in the Willamette Basin

Site	Plant Capacity 1,000 KW 1/	Head Ft.	Length Penstock Ft.	Daily Storage AF	Total Turbine Capacity cfs	Drawdown Upper Ft.	Drawdown Lower Ft.	Investment Cost $/KW	Capacity Cost $/KW Yr. 2/
Box Canyon	1,000	890	6,500	10,000	15,400	88	27	139	7.60
	2,000			20,000	29,900	134	48	128	7.00
Eighth Creek	1,000	1,340	7,400	7,300	10,200	42	48	127	6.90
	3,000			21,900	30,700	87	107	109	5.90
Erma Bell	1,000	1,590	4,200	6,000	8,600	89	16	107	5.90
	4,000			24,000	33,150	192	59	89	4.80
Gander Lake	1,000	1,700	15,000	6,000	8,100	46	82	134	7.30
	2,000			12,000	16,100	80	134	114	6.20
Summit Lake	1,000	1,790	12,500	5,300	7,600	7	21	113	6.20
Timpanogas	1,000	1,560	13,200	6,000	8,800	59	21	129	7.00
	2,000			12,000	17,350	100	55	108	5.80
Waldo Lake	1,000	2,190	21,000	4,600	6,200	1	16	144	7.80
	3,000			13,800	19,000	3	45	107	5.80
Beaver Marsh	1,000	1,270	12,700	7,800	10,800	44	87	145	7.80
Corral Flat	1,000	1,210	3,500	9,000	11,300	58	71	120	6.60
Cow Swamp	1,000	1,510	7,000	6,400	9,050	33	80	110	6.00
	2,000			12,800	18,300	57	120	88	4.80
Dead Horse	1,000	1,190	11,600	7,900	11,500	14	50	135	7.40
French Pete	1,000	1,630	10,500	5,800	8,400	92	20	125	6.80
	4,000			23,200	33,650	166	67	98	5.30
Honey Lake	1,000	2,000	11,000	4,800	6,900	53	22	111	6.10
	4,000			19,200	26,800	154	75	88	4.80
Melakwa	1,000	1,380	9,000	6,900	9,900	49	44	114	6.22
	2,000			13,800	20,000	82	84	102	5.50
Olallie Meadows	1,000	1,790	13,800	6,000	7,600	40	70	143	7.70
	3,000			18,000	23,250	88	142	113	6.10
Penn Lake	1,000	1,400	13,500	6,800	9,800	71	70	142	7.70
	2,000			13,600	19,700	114	124	121	6.50
Wildcat Swamp	1,000	1,450	8,500	6,700	9,450	29	59	125	6.80
Berley Lakes	1,000	1,290	10,600	7,600	10,600	36	23	126	6.90
Browder Ridge	1,000	1,620	7,600	6,000	8,500	133	34	116	6.30
	2,000			12,000	16,700	217	68	101	5.50
Bruno Meadows	1,000	1,700	11,000	5,500	8,000	43	10	129	7.00
	2,000			11,000	15,850	68	20	104	5.60
Downing Creek	1,000	970	2,300	9,700	14,100	54	37	137	7.40
	2,000			19,400	27,350	82	96	119	6.50
Elk Lake	1,000	1,910	19,000	5,300	7,200	19	27	134	7.30
	10,000			53,000	72,400	138	87	101	5.40
Falls Creek	1,000	2,440	8,800	3,800	5,600	44	13	126	6.90
	3,000			11,400	16,000	126	48	94	5.10

Effect of Pumped-Storage Plant Operation on Streamflow

Most of the sites located in this survey would be developed as hydraulically independent projects; the reservoirs would be comparatively small and would be used exclusively for pumped-storage operations. The large, irregular flows associated with peaking operation would occur only between the upper and lower reservoirs. Once filled, only a comparatively small amount of inflow would be required to make up leakage and evaporation losses. For the most part inflows would be passed and the operation of the project would have very little effect on the flows downstream.

Table IV-3 (Continued)

Site	Plant Capacity 1,000 KW 1/	Head Ft.	Length Penstock Ft.	Daily Storage AF	Total Turbine Capacity cfs	Drawdown Upper Ft.	Drawdown Lower Ft.	Investment Cost $/KW	Capacity Cost $/KW Yr. 2/
Gordon Meadows	1,000	2,730	11,000	3,500	5,000	31	25	132	7.10
	4,000			14,000	20,000	85	63	94	5.10
Harter Mountain	1,000	2,040	12,000	4,800	6,700	36	59	147	8.00
Little Meadows	1,000	1,660	9,000	5,800	8,200	77	74	123	6.70
Olallie-Monon	1,000	1,980	18,000	5,300	6,900	7	31	133	7.20
	10,000			53,000	75,500	54	183	96	5.20
Pigeon Prairie	1,000	1,390	7,000	7,500	9,850	27	17	117	6.40
	2,000			15,000	19,600	47	32	105	5.70
Snow Peak	2,000	2,210	22,000	8,400	12,400	114	38	129	7.00
	4,000			16,800	24,250	152	53	112	6.10
Swamp Peak #1	1,000	2,000	14,000	4,800	6,900	69	48	119	6.50
	2,000			9,600	13,700	125	58	100	5.40
Tumble Lake	1,000	2,270	10,500	4,300	6,400	39	2	112	6.10
	6,000			25,800	36,050	204	14	94	5.10
Battle Creek	1,000	1,080	11,000	8,400	12,600	71	27	144	7.90
	6,000			50,400	70,100	248	116	118	6.40
Big Eddy	1,000	1,560	3,200	6,300	8,800	42	20	101	5.60
	3,000			18,900	25,800	71	78	79	4.40
Cache Meadow	2,000	2,560	25,000	7,400	10,800	81	95	133	7.10
	4,000			14,800	21,700	127	158	116	6.20
Cottonwood	1,000	1,990	10,000	4,700	6,900	58	39	121	6.60
	6,000			28,200	40,300	194	208	85	4.60
Kink Creek	1,000	1,350	6,500	7,000	10,100	50	57	120	6.50
	2,000			14,000	20,200	74	80	91	5.00
Peavine	2,000	1,220	14,000	15,000	22,500	85	26	120	6.50
	6,000			45,000	65,800	151	62	118	6.40
Squaw Meadow	1,000	1,770	11,000	5,700	7,750	55	64	116	6.30
	2,000			11,400	15,600	88	112	95	5.20
Tarzan Spring	1,000	1,540	15,000	6,000	8,900	90	28	133	7.20
	3,000			18,000	26,050	160	63	115	6.20
Wanderer's Peak	1,000	1,840	12,000	5,000	7,400	103	62	121	6.60
	4,000			20,000	29,150	221	141	96	5.20
Latourell	2,000	3,040	22,000	6,000	8,950	59	Negl	121	6.50
Multnomah	1,000	1,730	3,000	5,700	7,900	48	Negl	95	5.20
Wind Creek	1,000	1,480	6,000	6,300	9,300	87	130	118	6.40

1/ Indicated minimum and maximum capacity.
2/ Based on 50-year project life and 4-5/8% interest.

Recreational Use

Almost every body of water is viewed by the public as a potential site for water-based recreation. While it is possible that a few of the pumped-storage reservoirs could be used for some recreation, not all of them could be fully used for both power and recreation due to conflicting needs for pool operation. In most cases, reservoir drawdown for power would be great; therefore, public access to pumped-storage project areas would have to be restricted.

Best Sites

Of the 43 sites listed in Table IV-3, 24 could be developed to provide an ultimate installed capacity of up to 2,000,000 kilowatts each; 13 could accommodate installations between 2,000,000 and 4,000,000 kilowatts; four sites could be developed with up to 6,000,000 kilowatts each; and two sites have potential for 10,000,000 kilowatt installation each. While all these sites show favorable investment costs, other factors may render them infeasible. Some sites are located in Wilderness Areas or other prime recreation areas, some would conflict with other existing land and water uses, and others might be impractical from a geological standpoint.

Of the 43 sites listed, a total of nine appear to be the most favorable and should be given first consideration for more detailed investigation. These sites are as follows:

Site Name	Tentative Maximum Installation (1,000 kilowatts)
Elk Lake	10,000
Little Meadows	1,000
Snow Peak	4,000
Tumble Lake	6,000
Battle Creek	6,000
Cache Meadows	4,000
Cottonwood	6,000
Squaw Meadow	2,000
Tarzan Springs	3,000

It should be emphasized that while this list is considered to include the most promising of the sites reviewed, this should not preclude consideration of the other sites in future studies.

It appears from this survey that there is considerable pumped-storage potential in the Willamette Basin--potential that could be developed in conjunction with base-load thermal plants. Considering only the nine most favorable sites, as listed above, there is a potential generating capacity of up to 42,000,000 kilowatts. Most of this capacity could be installed for less than $125 per kilowatt. More study will be required to see when and how pumped storage could best fit into the region's future load pattern, but it is evident that pumped storage offers considerable promise as a source of future peaking capacity.

FOSSIL-FUELED PLANTS

Studies of future electric power loads and resources show needs for additional generating capacity not only to supply the bulk of the energy requirements (base loads) but also to be used for only a few hours a day to meet peak demands. Most of the remaining sites in the area which can be economically harnessed for base-load generation are already being developed, or plans for their use are well under way. Thus, nearly all future energy requirements must necessarily be met by constructing large thermal generating plants.

New capacity to supply peak demands can be obtained by adding generating units at some of the existing hydroelectric plants and by constructing pumped-storage projects and fossil-fuel electric generating plants. Nuclear-fuel plants would not be developed for low plant-factor peaking operations largely because of their high capital cost.

The types of fossil fuel utilized in electric power generation are coal, oil, and natural gas. Steam-electric plants may use any of these types of fuel. There are no known deposits of coal, oil, or gas in the Willamette Basin capable of supporting large base-load, steam-electric plants. Transportation costs for moving such fuels to the basin are quite high. These circumstances inhibit the construction of such plants in the basin.

Gas turbines can be designed to operate by burning either natural gas or distillate oil. Gas-turbine generators possess many features which make them desirable for certain types of power-system duty. They have a low installed cost, quick start-up, require few auxiliaries, can be made semi-automatic in starting and stopping, and adapt readily to remote control, reducing the need for at-site attention by operating personnel. They can be located with considerable freedom, since their cooling water requirements are nil and they are not dependent on any single fuel source. Maintenance costs are low because of simple, compact construction with all parts readily accessible. Gas-turbine electric generators are ideal for use for peaking service.

Diesel-engine-driven generators offer the same advantages as gas turbines relative to installed costs, operation, and maintenance. They are superior to gas turbines when used for serving small general loads.

Steam-electric units designed for peaking capacity are different from base-load units. Steam peaking units operate at lower pressures and temperatures and use a simplified water-heating cycle. Oil- or gas-fired boilers permit rapid startup and shutdown, with minimum attention from a small number of operators. Maintenance requirements are also minimized by use of these fuels. All steam-cycle generating plants require cooling water in quantity and at low temperature to dispose of unused heat if their installed costs are to be low. Steam-electric peaking plants permit greater capacity in a single generating unit than either gas turbines or diesel units.

Each type of peaking unit referred to above has a range of application in which it is superior to the other two types. For strictly peaking duty--with usage of up to 200 to 400 hours per year at rating--any of the three types are superior to conventional base-load, steam-electric units. For spinning reserve operation, gas turbine and diesel-engine units are superior in small capacities and the steam peaking unit is superior in the medium and large capacities.

The variable cost of fuel for any generating plant is an important compontent of the total cost of production of energy from that plant. The other major cost component is the fixed charge resulting from the original investment in land and facilities. At base-load plants, variable fuel costs are much more important than at peaking plants. Conversely, at peaking plants low fixed charges are more important than the level of variable fuel costs.

NUCLEAR-FUELED PLANTS

In less than 30 years, the application of nuclear energy to generate electric power has evolved from the laboratory into commercial use. Emerging into a well-established field of keen competition in electric power generation, nuclear electric energy generating plants now under construction are expected to compare favorably in terms of power costs with other base-load power plants. This competition has contributed to major reductions in the price of coal and coal transport and has stimulated improvement in other alternative power-generating sources.

The demonstration that nuclear power is practicable, safe, reliable, and economically feasible is sufficient to assure its utilization. In the Willamette Valley, nuclear power can probably provide base-load electric energy at a cost lower than most other potential sources.

Historically, nuclear plants have cost more to construct than conventional steam-electric, base-load plants. Until recently, capital costs of nuclear plants had been declining rapidly on a per-unit capacity basis as the size increased. It is unlikely that capital costs of a nuclear plant will ever fall to the current level of fossil-fueled plants. However, the variable cost of nuclear fuel, if it is low enough, can offset the higher capital cost of a base loaded nuclear plant and make it economically competitive with a fossil-fueled plant. A more specialized operating staff is required for a nuclear plant than for "conventional" power plants.

Like ordinary fossil-fuel-fired, steam-electric plants, nuclear power plants use heat to produce steam to drive turbine generators. The major difference is that fossil-fuel-fired plants use heat produced by combustion of fossil fuel in a furnace, while nuclear plants use heat produced by fission of nuclear fuels in a reactor. Basically, a nuclear steam-supply system is substituted for the fossil fuel furnace and boiler. Shielding must be provided to contain hazardous radiation, and special containment facilities and other safety features must be incorporated to prevent the escape of radio-active material in the unlikely event of a reactor accident.

At present, large light-water nuclear plants waste about two-thirds of the total heat generated, due to low thermal efficiencies. High-temperature, gas-cooled reactors will operate at efficiencies of 40 percent or better. Fast Breeder Reactors presently under development are also expected to have cycle efficiencies of 40 percent or better; these FBR's are expected to become commercially competitive by the late 1980's.

Photo IV-3. Typical Natural-draft Cooling Towers (Tennessee Valley Authority Photo).

The problem of condensing the steam discharged from the turbines is common to both conventional fossil-fuel steam plants and nuclear steam plants. Water, the usual coolant pumped through the condenser, absorbs unusable heat given up by the condensing steam.

Present turbine-generators in thermal power plants operate most efficiently with a condensing temperature of 90-95 degrees Fahrenheit. This relatively low-temperature heat has no present market and is, therefore, wasted.

Heat-Dissipation Systems

The heat-dissipation systems applicable to either large nuclear or fossil-fueled power stations are: once-through cooling, evaporative, and dry exchange.

Once-through Cooling Systems

Power plants using once-through cooling systems need an adequate water supply; therefore, they must be located along rivers, lakes, and tidewaters. Water is pumped through condensers, absorbs heat, and is returned to the source. Once-through cooling systems are usually the simplest and least expensive when sufficient cooling water is available. The heat-dissipation rate from a 1,000,000-kilowatt nuclear power plant of 7 billion British Thermal Units per hour require about 1,600 cubic feet per second (720,000 gallons per minute) of water to limit the coolant temperature rise to not more than 20 degrees F. The cost of a fresh-water, once-through system will normally be 4 or 5 percent of the direct construction costs for the plant as a whole. Salt-water systems cost more due to the expense of noncorrosive materials, water treatment, and other facilities.

Evaporative Cooling Systems

Some plant locations may not have an adequate water supply for once-through cooling. Imposed temperature limitations, excessive costs for pumping, or other restrictions may also rule out the use of a once-through system.

Normally, an evaporative cooling system uses natural- or mechanical-draft cooling towers, cooling ponds, or spray ponds. These systems cool the recirculating water primarily by evaporation, augmented by convective transfer of heat to the atmosphere and, in some cases, by radiation of heat. Evaporative cooling systems require much less water than once-through systems. The water make-up requirements for a 1,000,000-kilowatt nuclear power plant may range from 25 to 100 cfs. These systems eject virtually the entire heat load to the atmosphere rather than to bodies of water, thus avoiding thermal effects on water quality or aquatic life.

Compared to once-through cooling systems, the evaporative systems have several disadvantages. They require greater capital expenditures and pumping power costs. They usually have higher condenser temperatures, which lower the capacity and efficiency of the turbines, resulting in higher generating costs. Furthermore, they use water consumptively; the plant, therefore, competes for water supply with irrigation, municipal, industrial, and other uses.

The operation of a cooling tower or pond might introduce unwelcome atmospheric conditions, such as fogging or "drizzle" downwind of the plant under some conditions. Disposing of "blowdown" flows from the system is also a problem. This blowdown flow, 1 to 4 cubic feet per second, consists of water heavily burdened with dissolved solids, both the naturally occurring substances in highly concentrated form and chemicals added for required treatment of the water system.

Natural-Draft Cooling Towers - Natural-draft systems utilize the density difference between the heated, essentially saturated air within the tower and the atmospheric air surrounding the tower, to establish and maintain circulation of air through the structure. The major structural feature of a natural-draft tower is a tall, hollow hyperbolic shell which acts as a chimney and creates a draft for air circulation. Cooling actually takes place in the lower part of the tower. These towers are quite large, on the order of 400 to 500 feet high and about 300 to 350 feet in base diameter.

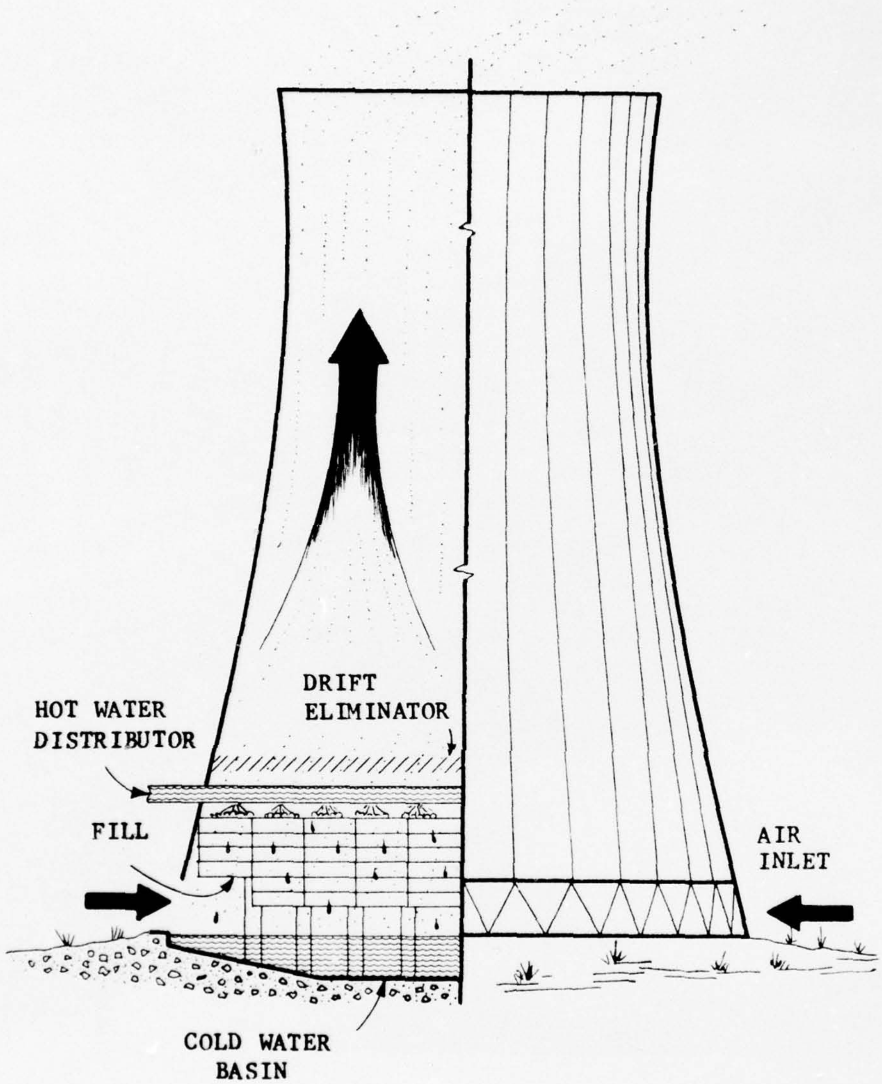


Figure IV-4. Natural-Draft Tower. Wet type (evaporative) counterflow.

Some 1,000,000-kilowatt nuclear plants would use two towers, each having a design flow of about 300,000 gallons per minute and a heat load of 3,600,000,000 Btu/hr. The average annual evaporation rate would be about 32 cfs. If such a plant were continuously operated at full capacity (100 percent plant factor), the total water consumption due to evaporation would be about 23,000 acre-feet per year. The capital costs of natural-draft tower systems for a 1,000,000-kilowatt installation are $8 to $9 million more than for comparable once-through cooling systems.

A single natural-draft tower currently being designed for the Trojan 1,100,000-kilowatt nuclear plant would use 352,000 gallons of cooling water per minute with a heat load of 7,900,000,000 Btu/hr. This will be the heaviest heat load handled by a single tower. The estimated capital cost is about $5 million more than a once-through cooling system. Figure IV-4 shows a natural-draft tower.

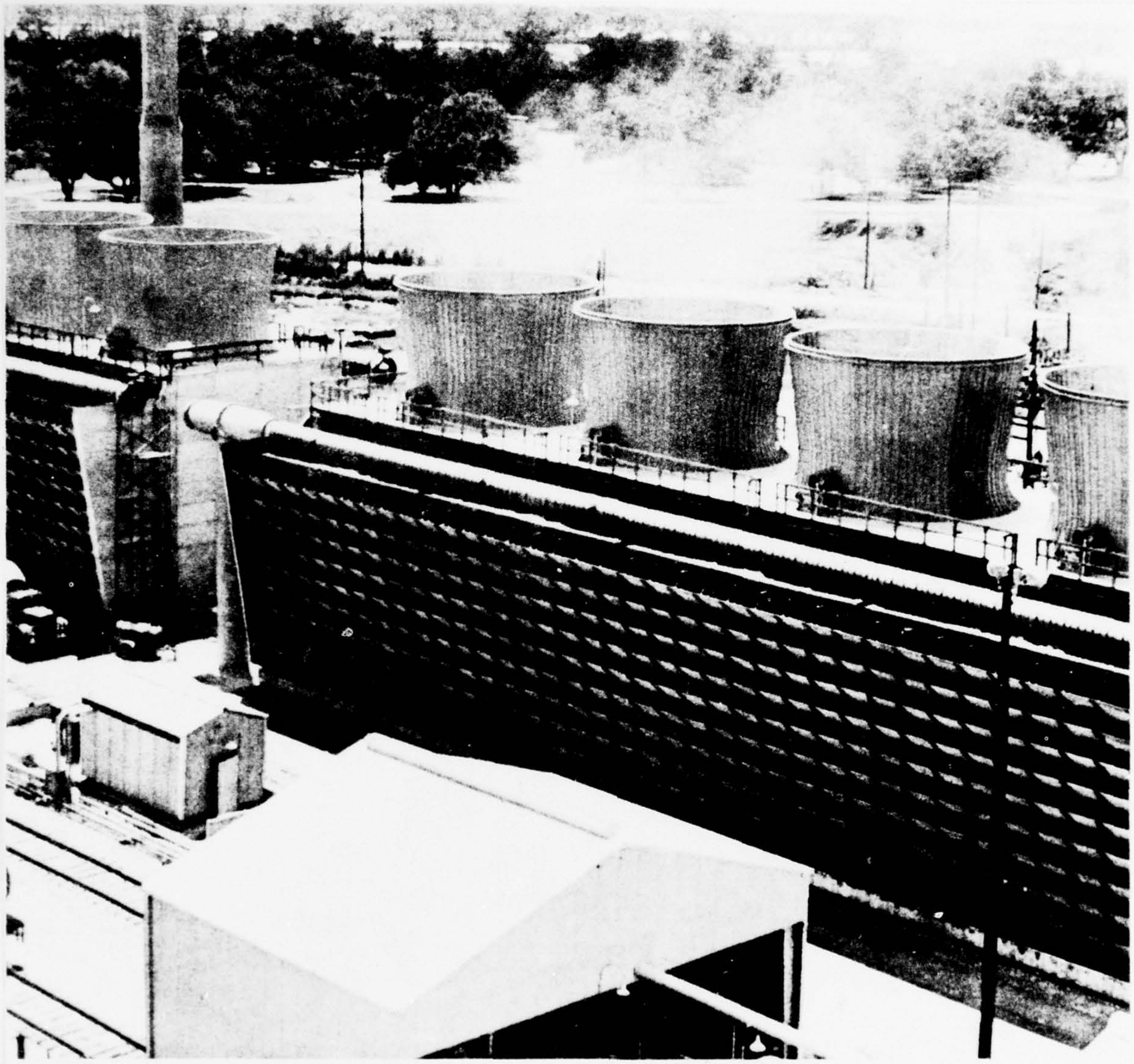


Photo IV-4. Two Mechanical Draft Cooling Towers, Cross Flow, Wet Type (Marley Photo).

Mechanical-Draft Cooling Towers - Systems with mechanical-draft cooling towers perform the same function as natural-draft systems, but in a different manner. The towers house the packing and water-distribution systems; a large propeller-type fan in the top of a tower cell draws air in through the packing and exhausts it above the tower cell. The available capacity of a single fan limits the cell size to about 35 to 40 feet on a side and from 20 to 60 feet high. A 1,000,000-kilowatt nuclear power plant might require 32 to 36 cells, widely spaced to minimize air recirculation, covering a ground area some 320 by 1,200 feet (about 9 acres). A plant of this size would require about 4,800 horsepower for fan operation.

The installation costs for a mechanical-draft system are considerably less than for a natural-draft system. Direct construction cost is about $4 million for a 1,000,000-kilowatt plant. However, operating and maintenance costs are considerably higher. These towers are also more apt to cause ground fogging and "drizzle" in the vicinity of the plant than the natural-draft towers. Photo IV-4 shows the wet-type mechanical draft cooling tower in operation.

Cooling Ponds - At sites with available land and favorable terrain, the cooling-pond method may be considered. With suitably flat land, a pond can be constructed merely by enclosing it with earth dikes; also, an existing lake, or river flood plain, may be utilized as a cooling pond. A pond capable of serving a 1,000,000-kilowatt nuclear power plant would require about 2,000 acres of surface area with a depth of from 15 to 20 feet. The exact amount of surface area would depend upon climatic conditions, local winds, and humidity.

A cooling pond must be sized to dissipate not only the heat removed from the condensers, but also the heat of sunlight incident to the pond. For a pond large enough to serve a 1,000,000-kilowatt plant, the solar thermal load may equal or exceed that imposed by the plant. Seepage may also cause a loss of water. Both of these effects add to the consumptive use of water by a cooling pond. The solar effect will, in warm summer weather, approximately double the evaporation rate of water as compared to a cooling tower.

Spray Ponds - This type of cooling considerably reduces the amount of surface area needed in a pond, since the hot water is sprayed into the pond through a system of nozzles. The cooling occurs while the water falls through the air. In operation, a spray pond is actually intermediate between a cooling pond and cooling tower. This type of cooling is subject to a high windage loss of water. Although a spray pond is an attractive cooling device for smaller heat loads, this type of cooling system for a large nuclear power plant would be more expensive than a quiescent pond or a cooling tower.

Hybrid Cooling Systems

When river flows are marginal for once-through cooling, or thermal restrictions are imposed on plant effluents so that once-through cooling would be operable for only part of the year, a hybrid system which combines two types may be necessary. In such cases, it might be desirable to install an evaporative system sized to full plant capacity for operation only when once-through cooling could not be used. The capital cost of the hybrid system would be equal to or greater than a full-scale evaporative system.

Dry-Exchange Cooling Systems

Dry-exchange cooling systems have certain advantages in that the circulating water system need not be separated from the condensate system and the water is pumped directly to the tower. All the heat is dissipated by convective exchange. Natural-draft or forced-draft towers may be used. With condensate-quality water used throughout the system, problems of scaling, corrosion and fouling of watersill heat-exchange

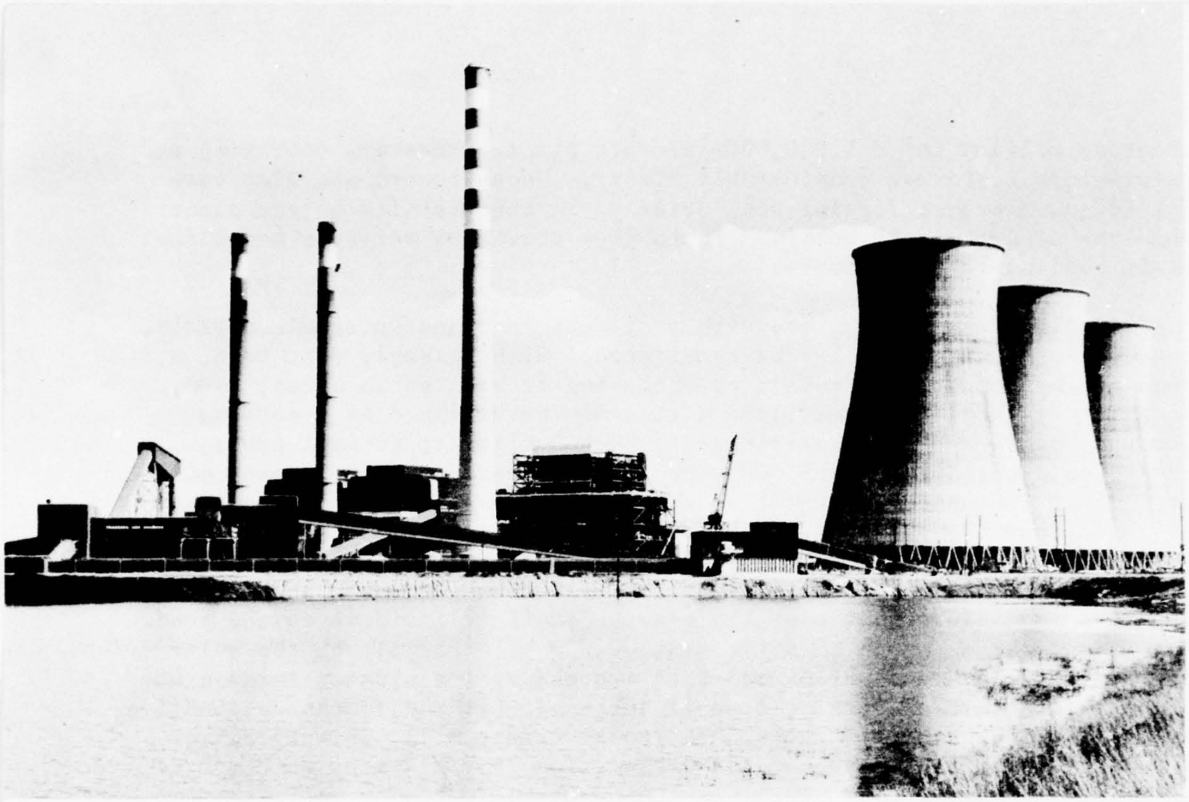


Photo IV-5. A Thermal Plant Using a Hybrid Cooling System (TVA Photo).

surfaces are minimized. This type of system consumes very little water, often a vital consideration in water-short areas.

However, the cost of the extensive tower piping and extended surface construction (such as finned tubing) required for dry-exchange systems may be four to five times that of an evaporative system. For a 1,000,000-kilowatt nuclear power plant, the cost of such a system would be prohibitive for any normal situation. Such a system would be considered only when sufficient water is not available for operation of other types of cooling systems.

Land Area Requirements and Uses

The decision of where to locate a large thermal generating station presents one of the most challenging problems an electric utility faces when planning to add capacity to obtain a power supply at the lowest cost. Factors considered include distribution of load, load growth, existing and prospective patterns of loading of the transmission system, interconnections with other systems, availability of land, foundation conditions, and availability of cooling water. There is also a growing concern that thermal discharges might harm the environment (atmosphere fogging, icing, and temperature rises in streams, lakes, and ocean water due to cooling-water discharge).

Federal regulations and other considerations establish the minimum required site area for nuclear plants. A 1,000,000-kilowatt light-water moderated nuclear plant site will need a minimum exclusion area having a radius of 3,000 feet. The term "exclusion area" is defined as an area immediately surrounding a nuclear reactor where human habitation is prohibited to assure safety in the event of accident. The exclusion area required for this size of nuclear plant site would contain about 650 acres, plus easements and access rights-of-way. For waterfront sites, the required land area will approximate a semicircle of some 325 to 350 acres. A site on a peninsula may require a much smaller area. The exclusion area may vary in shape from site to site depending upon local terrain, prior subdivisions, and the inclinations of the owners. This area including both land and water must be controlled by the plant owner.

Federal regulations specifically permit traversing the exclusion area of a nuclear power plant by highways, railroads, or waterways. Activities unrelated to operation of the reactor may be permitted in an exclusion area under appropriate limitations, provided that no significant hazards to public health and safety will result. The owner may, with Federal approval, allow agriculture, compatible industries, hunting and fishing, and even picnicking in the exclusion area providing there are no overnight facilities. Arrangements must be made for radiation monitoring, evacuation, and other safety precautions.

The number of good sites available for large thermal generation stations is decreasing because of competing demands for land and water required to service the growing population and fulfill its recreational needs. The interests of the electric utilities and their customers can best be served by constructing the largest economically justified generating complex on each site selected. Experts in reactor design predict that by 1980, single units of 1,500,000-kilowatts capacity will be in use in multi-unit plants, which will have a total installed capacity of more than 6 million kilowatts.

The handicap of restrictive site requirements in some localities could be overcome, at least partially, by including several reactor units on a single site. This would require that the isolation and safety provisions at the individual reactors are such that an accident at one reactor would not endanger the nuclear complex. In this case, an exclusion area not much larger than that provided for a single reactor probably would suffice. Unit costs could also be reduced by use of a reactor-fuel handling and maintenance facility common to all units, and by the use of other common facilities.

By fully exploiting the advantages of multi-unit nuclear stations, lower power costs as well as other benefits could be realized. The capital-cost outlay could be shared by several utility systems and result in establishment of a nuclear generation center. While such a development would reduce the number of nuclear plant sites, conserve valuable land, and provide economies of construction and operation, the cost of transmitting power from such a single large source throughout a large market area would have to be compared to the cost of transmitting from several strategically located and dispersed smaller sources and the disadvantage to national defense from a large concentration of capacity. However, a large-capacity transmission grid covering broad areas of the country would tend to minimize unit transmission costs and would result in additional potential savings in customer power costs.

Power Generation and Costs of Nuclear Plants

Nuclear plants to be built in the next decade in the Willamette Valley and those to be constructed in the distant future can be expected to operate at relatively high capacity factors (80 to 90 percent), because this manner of operation takes the greatest advantage of the plant's low energy costs. However, experience with existing plants operating elsewhere in the United States has shown that nuclear plants can follow load variations, i.e., be operated at low capacity factors of 40 to 60 percent if necessary.

The capital and operating costs of nuclear plants determine whether or not such plants are economically competitive with other types of thermal power plants. With nuclear plants, perhaps even more than with fossil-fuel thermal plants, installations with larger units tend to cost less per kilowatt to construct and to produce energy at lower unit costs.

Maximum Nuclear Power Requirements for Willamette Basin

As stated previously, nuclear power plants will be operated primarily to supply base-load energy requirements in the Pacific Northwest and Willamette Basin. Hydroelectric generation, both from within and outside the basin, will supply most of the peaking generation required, especially during the early years.

Most of the information available on land and water requirements for nuclear power plants is for the 1,000,000-kilowatt, single-unit size. If all the basin's energy requirements in 2020 are to be supplied by nuclear power plants within the basin, the equivalent of fifty-nine 1,000,000-kilowatt plants would be required. The capacity associated with the base load energy would be supplemented by importation of hydro peaking or by generation at pumped-storage plants or other peaking plants located within the basin. The following table shows the maximum land and water requirements in the basin if all the capacity was assumed to be built in fifty-nine 1,000,000-kilowatt nuclear plants with a single type of cooling system:

Table IV-4
Potential Land and Water Requirements for 59 Nuclear Plants

Cooling System	Site Area (Acres)	Cooling Pond Area (Acres)	Cooling Water (CFS)	Water Consumed (CFS)
Once-through	20,650	-	94,400	71
Evaporative*	38,350	-	-	2,124
Ponds	17,700	88,500	-	3,540

*For either natural draft or induced draft cooling towers.

The figures presented here are for maximum requirements. Actually, various types of cooling systems will probably be used. Also, many of the plants may be located outside the Willamette Basin, on the coast, or on large lakes.

Possible Nuclear Power Development in Willamette Basin

The Bonneville Power Administration research report, "Nuclear Power Plant Siting in the Pacific Northwest," by Battelle Northwest, presents two example sites for nuclear power plants in the Willamette Basin. Both of these 1,000,000-kilowatt nuclear power plant sites would require evaporative cooling systems. One site in the middle part of the Willamette Basin is on the Santiam River. The other site is in the southern part of the basin on the Willamette River.

The Eugene Water and Electric Board has under consideration a 1,000,000-kilowatt nuclear power plant. In July 1967, the Board voted to seek out an engineering firm to make preliminary design and site studies. A bond issue for financing the plant was authorized on November 5, 1968, by the electorate. Site selection studies are well underway. EWEB plans for operation of the plant to begin about the end of 1976.

Portland General Electric Company is building the Trojan nuclear generating plant on the Oregon side of the Columbia River 4.5 miles south of Ranier. The site is only a few miles outside the northern boundary of the Willamette Basin. The 600-plus-acre site is near large electrical loads (Portland is 42 miles southeast of the site). The plant, which includes a large cooling tower, has been granted a waste discharge permit by the Oregon State Environmental Commission. The Trojan plant will generate more than a million kilowatts of electricity from the atom when completed in 1974. It is expected to cost $206 million.

Pacific Power and Light Company has considered a prospective site for a large thermal-electric plant east of Lebanon, Oregon. However, development on this site has been delayed.

FUTURE TRANSMISSION FACILITIES

Providing sufficient rights-of-way for the increasing number of transmission lines presents one of the utilities' biggest problems. This will be particularly true for the movement of power from the main sources of generation east of the Cascade Range to the population and industrial load centers to the west. The Pacific Northwest load is estimated to increase from about 13 gigawatts (13,000,000 kilowatts) in 1965 to approximately 91 gigawatts in 2000 and 229 gigawatts by 2020.

The Willamette Basin will experience load growth from 2.65 gigawatts in 1965 to 27.3 gigawatts at the turn of the century and 91.8 gigawatts by 2020. Local thermal generation will be installed to meet much of the increase in energy loads. However, some large-block, extra-high-voltage power transmission from areas outside of the basin will likely be necessary to meet peak demands.

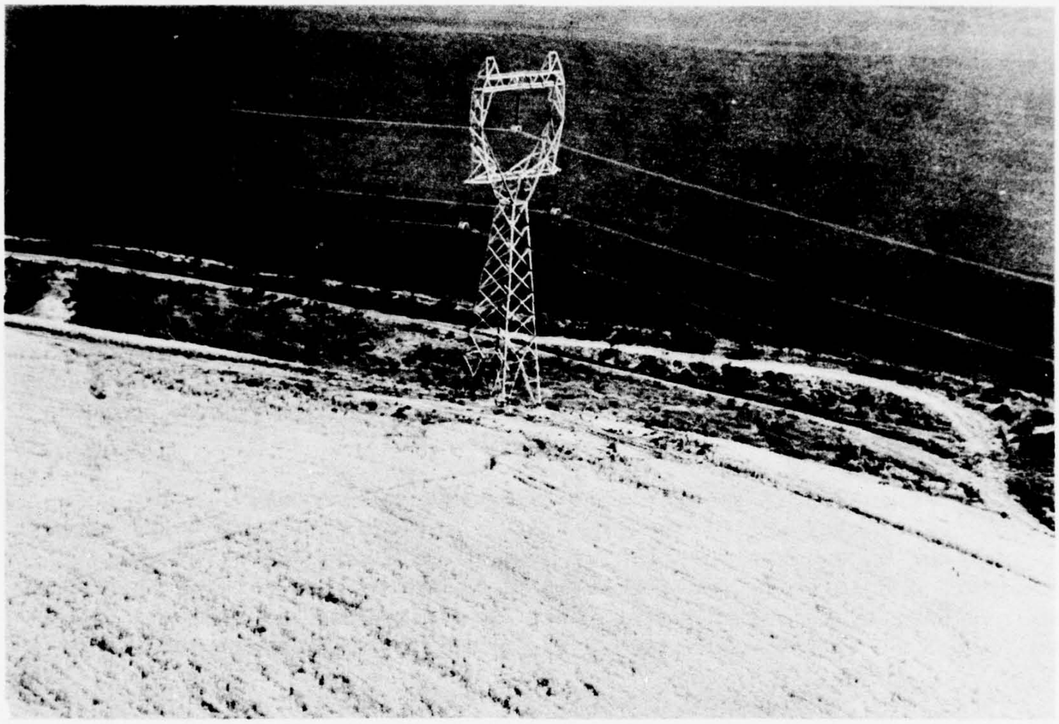


Photo IV-6. 500-kv Transmission Line (USBPA Photo).

By 1990, when virtually all of the feasible hydro sites in the Northwest will have been developed, loads are expected to more than triple 1970 levels. This will require transmission additions almost double the capacity previously built. (See Map II-3).

At present, with an essentially all-hydro system, three-fourths of the load requirements for the Willamette Basin are imported from hydroelectric generation sources east of the Cascades. As the transition to a thermal-generation base progresses, such plants within or adjacent to the basin will be needed to meet more and more of the area's load requirements. However, these will be primarily base-load plants, with peaking requirements largely supplied by hydroelectric plants east of the Cascades. This means construction of new transmission lines into the Basin with attendant increases in rights-of-way. Some additional north-south lines will also be needed to provide integration and bulk-load power transfers within the basin and with adjacent load areas.

By the fall of 1970, three 500-kilovolt lines into the Willamette Basin will be needed in addition to the existing 230-kilovolt system. By 1980, the equivalent of seven 500-kilovolt lines into the area will be needed; and by 1990, the transmission equivalent of ten 500-kilovolt lines will be necessary. Competing needs for land use will, no doubt, preclude the construction of this many transmountain lines. This total even exceeds the estimated capacity of the available mountain-pass routes. Clearly, other measures for providing the necessary transmission capacity are required, such as increasing the capacity per circuit or developing new methods of electric power transmission. Possible transmission development for the basin by 1990 is shown on Map IV-2. The regional transmission grid, including lines in the Willamette, is shown on Map IV-3. Present plans call for the construction of several of these lines at voltage levels in excess of 500 kilovolts.

LAND REQUIREMENTS

The land required for electric power transmission has been a problem not only in areas of concentrated population, but through urban, rural, forested, recreation, and other areas as well. However, as transmission voltages increase, the land required per kilowatt for transmission right-of-way decreases. Future transmission lines must have markedly greater power transmission capacities per right-of-way to reduce their impact on land use and remain within the limits of available rights-of-way. Increasing transmission voltage levels provide one method of accomplishing this, since line capacity increases approximately as the square of the voltage. For example, one 500-kilovolt line carries four times as much power as a 230-kilovolt line; yet, its 150-foot right-of-way is only 25 feet wider than that of a 230-kilovolt line.

By 1980, there will be in operation, planned, or under construction some 510 circuit-miles of 500-kilovolt or higher capacity lines in the Willamette Basin. The land requirements for these lines would approximate 9,800 acres if new rights-of-way were required for all. However, portions of the new lines will be routed over existing rights-of-way now occupied by lower-voltage lines which will be retired. This will increase the transmission capacity per right-of-way and reduce the need for new rights-of-way.

Additional 230-kilovolt transmission lines in the Willamette Basin will also be required. These lines will serve as integrating lines within the area and as sub-transmission for customer service.

Whatever future land requirements may develop, the need for careful location of transmission corridors with respect to other land uses will continue. Where possible, planners will route transmission lines through areas having the least conflict with other uses.

RESEARCH AND DEVELOPMENT

One transmission alternative under serious study is that of going to voltage levels in excess of 500 kilovolts. Several 700-kilovolt class lines are in operation or under construction in this and other countries. Since a 700-kilovolt line has approximately twice the capacity of a 500-kilovolt line, use of this voltage level as an overlay to the extensive 500-kilovolt grid being developed would reduce the circuits required and the impact on land use.

Studies are also progressing on 1,000-kilovolt transmission facilities. A 1,000-kilovolt line has approximately four times the capacity of a 500-kilovolt line. This voltage level could reduce the total number of lines still further. However, to maintain reliability and continuity of service, an orderly strengthening of the system is needed (at 500 kilovolts) before going to the higher voltage. The higher the line capacity, the greater the impact on the system when that line is lost due to a short circuit or some other contingency. Further studies are necessary to determine the optimum level of voltage for the circuits comprising the next grid overlay, both from a technical and an economic standpoint.

The laying of underground cable on existing rights-of-way is another method of increasing the transmission capacity of each right-of-way. Today, this method would cost 10 - 25 times as much per kilowatt as overhead lines. Research continues because in certain areas, such as large metropolitan centers, underground transmission is the only acceptable method. In this case, transmission distances are short and the increased costs have much less impact on system power costs than for a transmission distance of 100 - 300 miles.

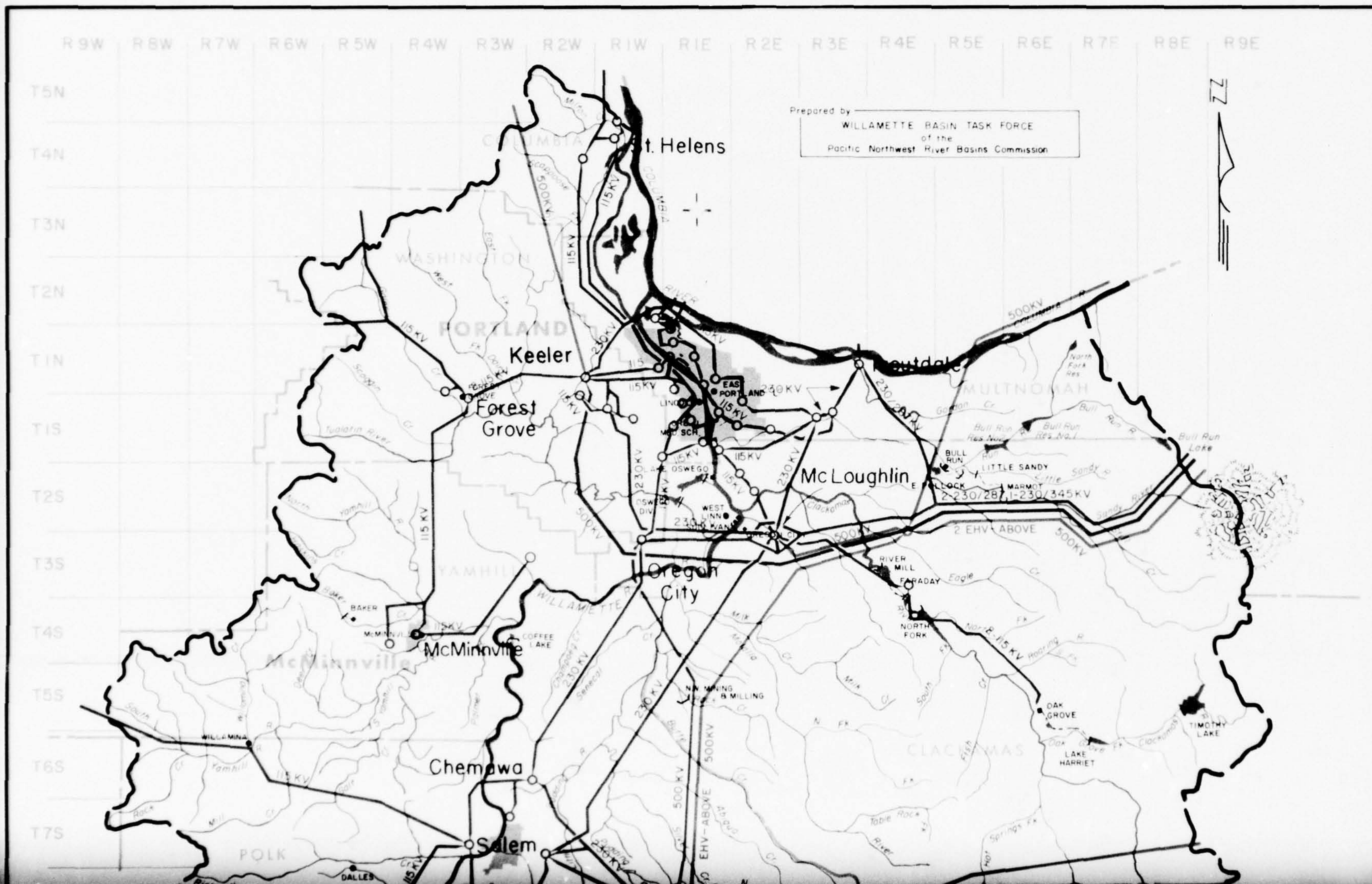
Direct-current transmission may be employed for large-block power transfers in future years. At the present time, direct current can compete economically with alternating-current transmission only when distances are greater than approximately 500 miles for overhead lines and 30 - 60 miles for underground cables. Direct-current terminals are more complex and costly than a-c substation equipment, but d-c line costs are only about two-thirds those of alternating current. Since most future transmission distances in the Northwest will be less than 300 miles, direct current will provide no economic benefit unless terminal costs can be markedly reduced. Some practical advantages of d-c are: (1) the more sophisticated controls help damp oscillations and undesirable power surges from the a-c system with which it is interconnected and (2) the ability to add major power infeeds to a system without increasing short circuit duties on existing equipment. If other factors require going underground, direct-current cables could become very attractive.

The cryogenic (low temperature) field may accelerate the use of d-c transmission with the development of superconducting cables having many times the capacity of conventional lines or cables. By refrigerating the conductors to temperatures near absolute zero, a system can attain transmission of power essentially without losses thus allowing very high power flows per circuit. Even though the cost per circuit would be high, the unit cost per kilowatt transmitted could be quite low.

Research is progressing on superconductors, but thus far no significant breakthroughs have resulted. Successful development of an ambient-temperature superconductor would revolutionize the whole field of power transmission.

EFFECTS OF THERMAL PLANT LOCATION

Thermal plants will in general be located adjacent to or near the major load centers to minimize transmission costs, both in facilities required and in transmission losses. Of course, a number of other



Prepared by
WILLAMETTE BASIN TASK FORCE
of the
Pacific Northwest River Basins Commission
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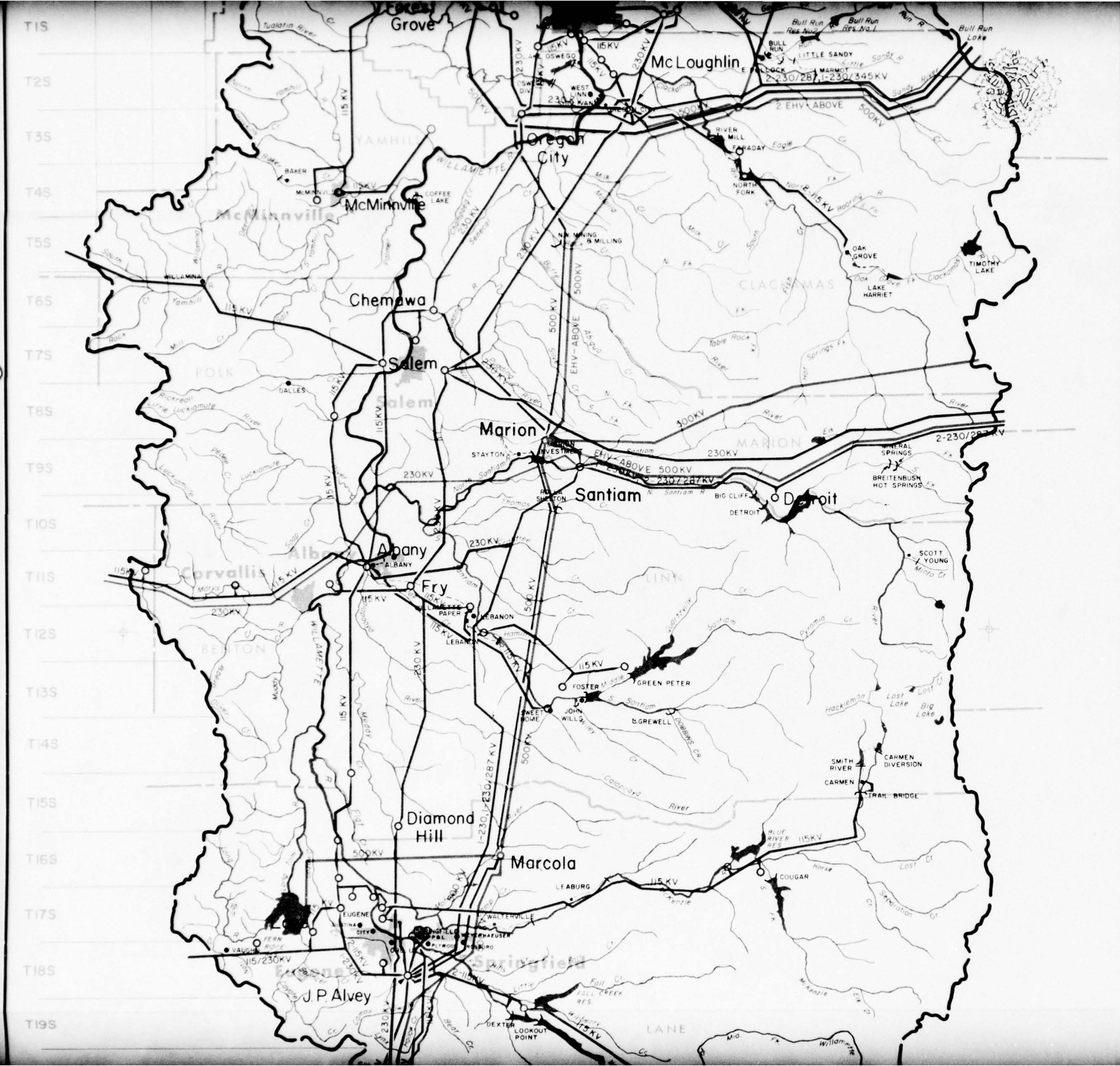
COLUMBIA
WASHINGTON
PORTLAND
MULTNOMAH
YAMHILL
CLACKAMAS
POLK
500KV
230KV
115KV
2 EHV ABOVE
2-230/287,1-230/345KV
EHV-ABOVE
BULL RUN
LITTLE SANDY
MARMOT
RIVER MILL
FARADAY
NORTH FORK
OAK GROVE
LAKE HARRIET
TIMOTHY LAKE
Bull Run Lake
COFFEE LAKE
BAKER
WILLAMINA
DALLES
WEST LINN
LAKE OSWEGO
NW MINING & MILLING



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Grove
McLoughlin
2-230/287, 1-230/345KV
2 EHV-ABOVE
500KV
Oregon City
McMinnville
Chemawa
Salem
Marion
Santiam
Detroit
Albany
Fry
Diamond Hill
Marcola
J.P. Alvey
Springfield
Eugene
Corvallis
YAMHILL
POLK
CLACKAMAS
MARION
LINN
BENTON
LANE
WILLAMETTE
115KV
230KV
300KV
EHV-ABOVE 500KV
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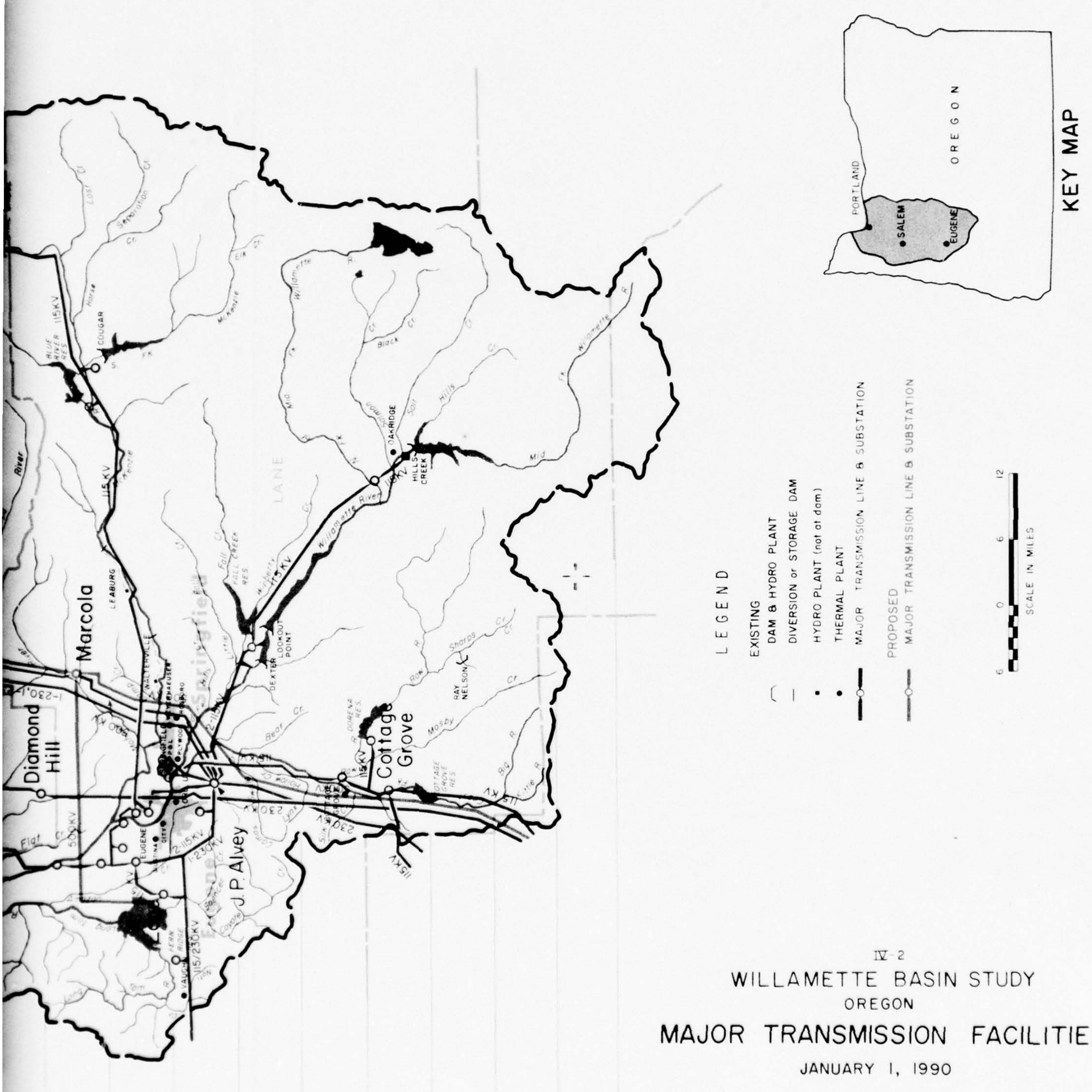
115/230KV
BULL RUN
LITTLE SANDY
MARMOT
RIVER MILL
FARADAY
NORTH FORK
OAK GROVE
LAKE HARRIET
TIMOTHY LAKE
WEST LINN
LAKE OSWEGO
BAKER
COFFEE LAKE
WILLAMINA
DALLES
STAYTON
BIG CLIFF
DETROIT
MINERAL SPRINGS
BREITENBUSH HOT SPRINGS
SCOTT YOUNG
LEBANON
FOSTER
GREEN PETER
SWEET HOME
JOHN WILLS
GREWELL
DOBBINS CR.
SMITH RIVER
CARMEN
CARMEN DIVERSION
TRAIL BRIDGE
BLUE RIVER RES.
COUGAR
LEABURG
WALTERVILLE
WEYERHAEUSER
FERN RIDGE
VAUGHN
FALL CREEK RES.
DEXTER
LOOKOUT POINT



IV-2

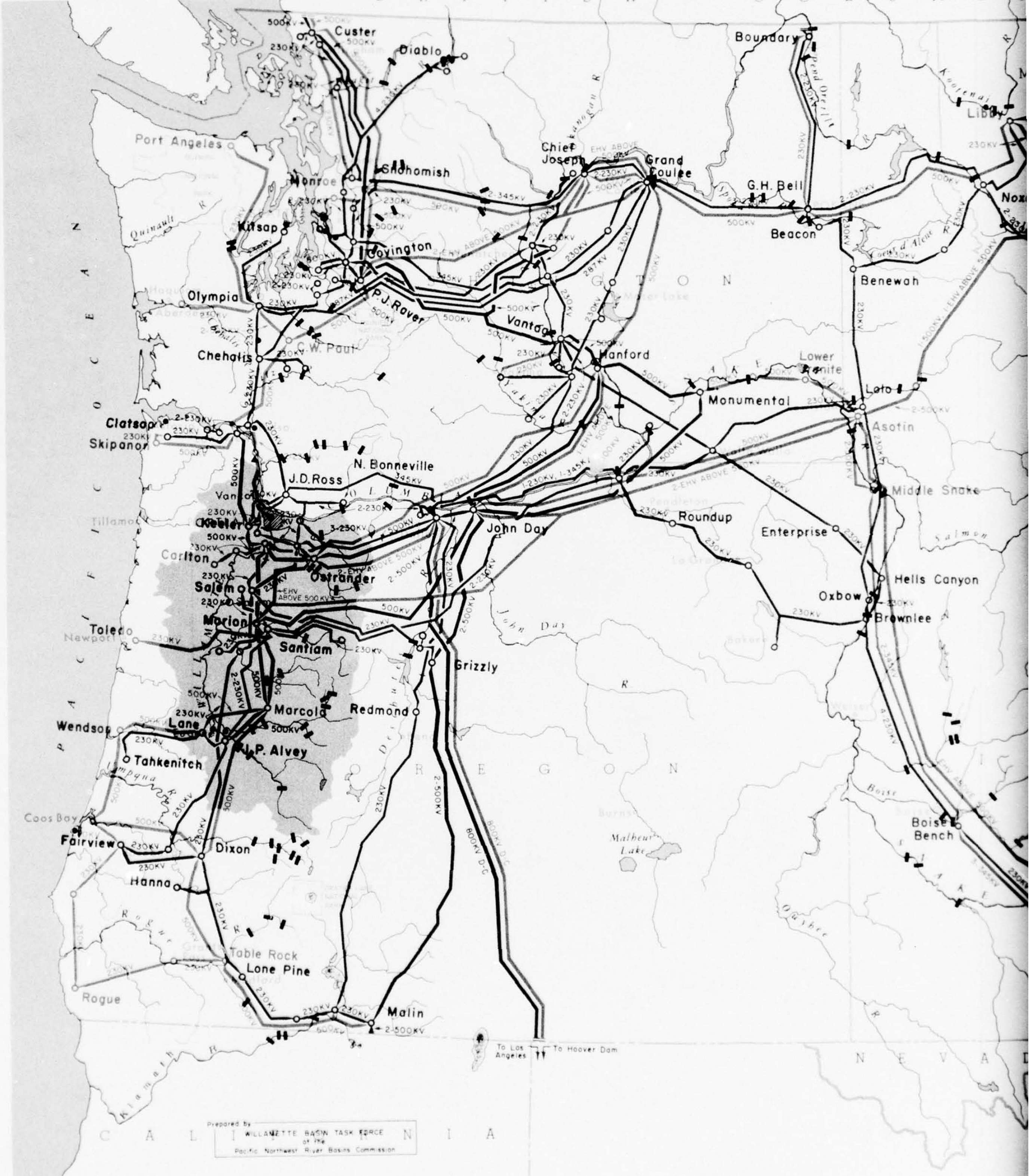
WILLAMETTE BASIN STUDY

OREGON

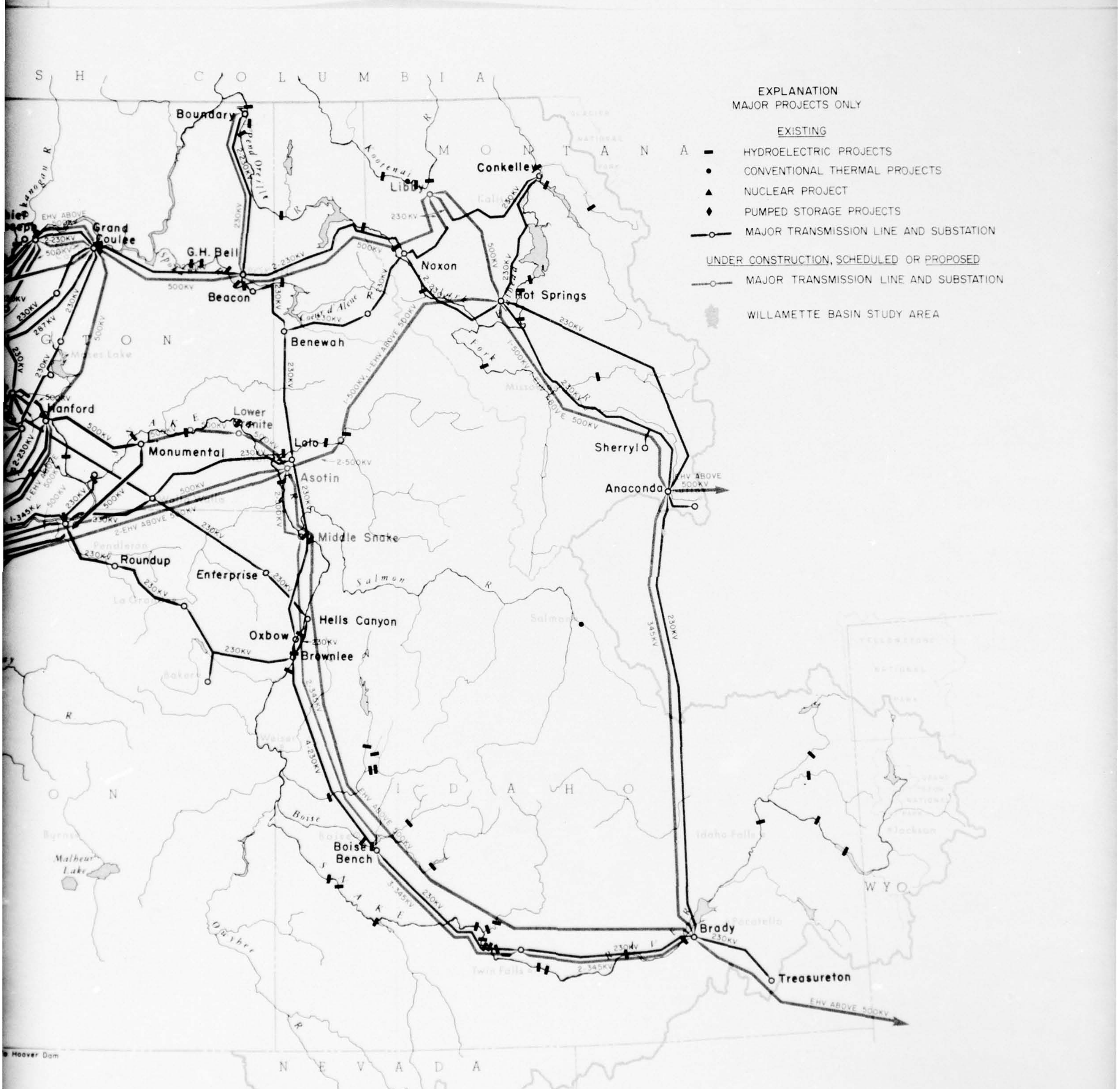
MAJOR TRANSMISSION FACILITIES

JANUARY 1, 1990

WBTF-0-1178-LL



B R I T I S H   C O L U M B I
P A C I F I C   O C E A N
O R E G O N
N E V A D
C A L I F O R N I A
Custer
Diablo
Boundary
Libby
Port Angeles
Chief Joseph
Grand Coulee
G.H. Bell
Snohomish
Monroe
Kitsap
Covington
Beacon
Benewah
Olympia
P.J. Rover
Vantage
Chehalis
C.W. Paul
Hanford
Lower Granite
Monumental
Lolo
Asotin
Clatsop
Skipanon
J.D. Ross
N. Bonneville
Middle Snake
Keeler
Roundup
John Day
Enterprise
Carlton
Ostrander
Salem
Hells Canyon
Oxbow
Brownlee
Toledo
Marion
Santiam
Grizzly
Redmond
Marcola
Wendson
Lane
J.P. Alvey
Tahkenitch
Coos Bay
Fairview
Dixon
Hanna
Boise Bench
Malheur Lake
Table Rock
Lone Pine
Rogue
Malin
To Los Angeles
To Hoover Dam
500KV
230KV
345KV
2-230KV
2-500KV
800KV D-C
EHV ABOVE 500KV
Prepared by
WILLAMETTE BASIN TASK FORCE
Pacific Northwest River Basins Commission



MAP IV-3
PACIFIC NORTHWEST

MAJOR TRANSMISSION FACILITIES

JANUARY 1, 1990

WBTF-X-1181-LL

factors will influence plant location. Among these are environmental geologic considerations and the desire of the constructing agencies t locate thermal plants within their service area.

Studies based upon transmission considerations alone have been m for determining the optimum scheduling and location of these plants through 1985. Results indicate that the preponderance of the new the mal plants to be constructed by 1985 should be located west of the Ca cades and south of Puget Sound. Power normally flows to the West and South in the western portion of the Northwest grid. The Portland are is approximately 100 miles farther from the large mid-Columbia genera ing complex than the Puget Sound region. In effect, locating a plant in the Portland area rather than Puget Sound would save approximately 100 miles of transmission line plus resultant line losses. This patt would continue during the early period of thermal additions only. Wh the north-south flows on the coastal grid are reduced to low values, distribution of new thermal plants will follow the load growth patter

P R O B L E M S

Future demands to satisfy electric power requirements of the Wil mette Basin will create two general problems--competition among vario land and water uses, and disposal of thermal plant cooling water.

Fluctuations of electric power demands will normally be met by i tegrated production from thermal and hydro plants. An important valu of the hydro plants in the basin will be their ability to produce pea ing power. Peaking-power generation usually requires reregulation of power plant releases. Development of the remaining Willamette Basin conventional hydroelectric sites will require reregulation facilities if they are to be operated as high-capacity peaking plants.

Technological advances, increased competition for water, and use of surplus thermal energy to supply pumped-storage plants will aid in assuring the feasibility of thermal plants. While the basin is expec to remain a power-deficient area, large thermal plants--nuclear or fo sil-fueled--will probably become a reality in the basin and be coordi ted with hydroelectric plants to keep power imports to a minimum.

Competition among power generation, distribution, and other usua more publicized land and water uses has increased greatly in the past few years and will become critical in the future. Irrigation, fish a wildlife, recreation, power, flood control, municipal water supply, navigation, and water quality control are uses which must be consider in the management of water resources. Water scheduling practices in managing multiple-purpose reservoirs are helping to minimize competit between water uses.

High-voltage transmission lines may eventually be placed underground, thus alleviating problems involving agriculture, timber, and aesthetic interests.

The lack of large coal deposits in the basin will preclude the construction of large fossil-fuel, steam-electric plants and favor construction of nuclear plants. Another factor favoring nuclear plants is that air pollution from the alternative fuel-fired plants is avoided.

Disposal of thermal-plant cooling water is one of the economic problems facing power interests. Most of the rivers of the basin are too small or too warm to permit disposal of heated discharges from large thermal plants. The water quality standards of the State of Oregon will not permit disposal of untreated heat discharges which would elevate the temperature of the stream beyond the limits set. Nuclear plants will likely need large cooling towers or ponds, which add to the costs. A possible, but as yet untried, solution would be to make water from cooling ponds available for irrigation. Experiments are presently under way to determine the effects of using heated water for irrigation.

Cooling water requirements for the large amount of nuclear-fueled generation needed to supply the basin's energy requirements will present a serious problem. For the estimated equivalent of fifty-nine 1,000,000-kilowatt plants needed by the year 2020, the annual consumptive use of water under the alternative cooling methods would amount to over 50,000 acre-feet for once-through cooling, about 1,500,000 acre-feet with cooling towers, or up to 2,400,000 acre-feet with all plants using cooling ponds. Water storage would have to be allocated from sources in the basin to supply the water consumed during the summer and possible some for winter use. This would require the development of additional storage in the Willamette Basin by 2020 to conserve runoff for this purpose. From about 0.2 to 10 percent of the average annual runoff of Willamette Basin would be needed to supply the 2020 consumptive use if the total energy supply is developed in the basin with nuclear plants.

An alternative to building base-load power plants in the basin is to locate projects among the Oregon Coast or in other areas and import power. Two problems immediately arise, (1) transmission corridors must be made available, and (2) objections to construction along coastal areas must be overcome. These or similar problems remain to be solved regardless of what area Willamette Basin planners look to for sources of power. If such an alternative is adopted, additional back-up sources such as pumped-storage projects should be developed in the basin to provide for greater reliability of service.

Doubling the electric power production about every 10 years is necessary to keep up with power demands in this area. An early start on a good public information program is necessary, telling the people what is needed, what is planned, and why and how their community benefits. The people must be made aware of the need for more dams, for pumped-storage projects, for large thermal generating facilities, of the safety of nuclear power plants, and of the transmission system necessary to deliver power to the consumer. It is expected that improved power technology will be developed before the end of the century to resolve some of the problems foreseen for the basin and the power industry throughout the world.

PART V

CONCLUSIONS

SUMMARY

The history of electric power development in the Willamette Basin dates back to the 1880's. The first long distance power transmission line in the nation was constructed in the Willamette Basin, with the Portland city streets lighted by electric power generated at the Willamette Falls hydroelectric plant. The Pacific Northwest region's advanced technology of power production and transmission is recognized throughout the world. Here, residential power consumption is among the world's highest per capita. Private and public agencies have worked together to give the basin a dependable supply of low-cost power. The basin alone is not self-sufficient in its power supply, but its deficiency is made up by importing power from generating sources to the north and east. This power is transmitted over the region's vast network of high-voltage transmission lines. Large hydroelectric projects on the Columbia River supply much of the power used in the Basin.

The power demands of the basin are expected to climb to more than 90 million kilowatts by the year 2020 and there will continue to be a need for supply at a reasonable cost. Historically, the consumption of electric power has nearly doubled every decade. It is predicted that 70 percent of all energy used will be electrical by the turn of the century. The means of serving this need must advance correspondingly. The total installed generating capacity in the Willamette Basin is now about 938,000 kilowatts. The maximum peaking capability of all power plants in the basin was only about 27 percent of peak demand in 1968 and would be less than 1 percent of peak demand in 2020. In calendar year 1968 about 3 billion kilowatt-hours of electric energy was generated in the basin. That was some 17 percent of the year's requirements but would be only about six-tenths of 1 percent of forecast energy needs for 2020. Estimated future electric power requirements are:

Year	Peak Demand 1,000 Kilowatts	Annual Energy 1,000 Kilowatt-hours
1980	7,730	38,400,000
2000	27,300	136,000,000
2020	91,800	457,000,000

The basin's industry has experienced profitable operations under favorable business conditions. It has a productive, highly educated work force. Industry is moving into the basin at an accelerating rate, using more and more of the low-cost electric power available. The growth of an area can be directly related to its use of energy. A megalopolis is developing within the Willamette Basin. By 2020, it is expected to encompass the Eugene, Salem, and Portland areas, and extend north to Seattle. This will require a massive increase in generating plants and transmission systems.

FUTURE POWER SUPPLY

Several possible means to satisfy the projected electric power needs have been studied. The basin's potential hydroelectric sites have been inventoried with the single objective of power supply. The probable resources for the future include, along with increased power imports from outside the basin, nuclear powerplants to supply the around-the-clock base loads, pumped-storage plants to supply peaking, and possibly some small conventional hydroelectric plants supplementing both base and peak load power supplies.

Several possible nuclear powerplant sites for the basin have been mentioned but only one plant, Trojan, has advanced to the actual construction stage. By the year 2020, it is estimated that up to 49,000,000 kilowatts of nuclear capacity or alternatives will be needed to supply base-load requirements of the basin in addition to power supplied from existing and projected hydroelectric and thermal plants and from imports. While nuclear plants utilizing conventional steam turbines connected to generators are used today, research is being conducted on the use of thermionic generators, fuel cells, magneto-hydrodynamic (MHD) generators, and nuclear fusion reactors. In MHD generators, electrodes are placed in the high-temperature jet stream of gasses forced at high velocity through a magnetic field; direct current at relatively high voltage is obtained.

The basin has no significant fossil-fuel supply; therefore, any development of this type of generation would require that fuel be imported. Current estimated transportation costs for moving such fuels to the basin are quite high. These circumstances inhibit the construction of base-load fossil-fueled plants in the basin. Gas-turbine peaking plants or fossil-fuel fired steam peaking units are alternatives to conventional or pumped-storage hydroelectric peaking power.

The potential for conventional hydroelectric development is limited. The aggregate capacity which might be developed at some 24 sites identified in this study would provide about 760,000 kilowatts.

The basin has a vast potential for pumped storage. Considering only the nine most favorable sites, 42,000,000 kilowatts of capacity could be developed. About 26,000,000 kilowatts of peaking capacity will be needed in the basin to supplement other power sources. This potential peaking could be developed when sufficient base-load thermal plants have been installed and after the more economical peaking additions have been made at existing hydro plants in the Northwest. In 20 to 30 years, pumped storage will become competitive with other methods of supplying peaking power. Future thermal plants will be supplying the base-load power and off-peak energy for pumping power. Water for pumped storage may serve a dual purpose, that for generating power for peaking and as steam-plant condensing water.

Import of power from outside the basin is expected to increase, however, it is unlikely that all of the increase in power requirements could be imported. Planners have forecast that approximately 16,000,000 kilowatts will be brought into the basin to help meet demands for the years 2000 and 2020. This will require substantial additions to the region's transmission grid. Before long, the Pacific Northwest will probably be tied to other power-producing regions by giant power grids electrically integrating the eastern-western and northern-southern United States and parts of Canada. This will permit taking advantage of diversity in power requirements between the northern and southern climates, and between the eastern and western areas.

Research on improved power transmission is under way. Under investigation are wave propagation via wave guides, wireless transmission of energy, and super-conducting circuits. Cryogenic research may develop practical super-cooled conductors where resistance to flow and accompanying power loss approach zero. This will permit vast quantities of power to flow over a single circuit. Reliability of service is also a must for the transmission system developing in the basin. As the growing populace uses electricity in ever increasing quantities, an abundant and uninterrupted supply of power becomes more important.

R E C O M M E N D A T I O N S

Power has played an important role in elevating man's standard of living to its present level. The man of tomorrow will use some 20 times the energy he uses today. A plentiful supply of reliable electric power at a reasonable cost is needed to promote future growth. The greatest reliability of service is obtained from local generation using local resources, thus eliminating some hazards inherent with long-distance transmission.

Power resource development should be responsive to the whole spectrum of man's requirements--land, water, air, food, housing, light and power, communication, recreation, etc. All must be considered so that one is not developed to the exclusion of others. But man's demand for comfort and convenience in the form of electric power must be considered in the light of importance to his greatest good. Because of the competition for the use of land for purposes other than power, there is an urgent need for the proper authorities to take immediate steps to reserve desirable conventional hydro, pumped-storage, and thermal-electric power sites for future development. Also, proper investigations should be conducted to assure public acceptance of the selected sites for future power use.

While problems associated with power production and transmission throughout the basin seem formidable, management and engineers of the power industry are confident that advances through research and technology will overcome them. Research will ultimately provide methods of power production and transmission that are unknown today. Further study and planning must be continued to assure the orderly development of fossil-fueled, nuclear, conventional hydro, and pumped-storage electric generating plants to supply the future power needs of the basin. Sufficient time must be allowed for development of a project before it is

Photo V-1. 500-kv Transmission Line Crossing Farm (USBPA Photo).

actually needed. For example, the lead time necessary for planning, licensing, and constructing a nuclear power-generating plant is about 7 years.

THE COMPREHENSIVE PLAN

Analyses leading to the development of a comprehensive plan for use of the basin's water and related land resources and how these resources will contribute to meeting future power demands are presented in Appendix M - Plan Formulation.

ADDENDA

GLOSSARY

POWER AND RATE TERMS

CAPABILITY

Peaking Capability - the maximum peak load that can be supplied by a generating unit, station, or system in a stated time period. It may be the maximum instantaneous load or the maximum average load over a designated interval of time.

CAPACITY

Dependable Capacity - the load-carrying ability of a station or system under adverse conditions for the time interval and period specified when related to the characteristics of the load to be supplied. Dependable capacity of a system includes net firm power purchases.

Installed Capacity - the total of the capacities as shown by the name-plates of similar kinds of apparatus such as generating units, turbines, synchronous condensers, transformers, or other equipment in a station or system.

Peaking Capacity - generating equipment normally operated only during the hours of highest daily, weekly, or seasonal loads. Some generating equipment may be operated at certain times as peaking capacity and at other times to serve loads on a round-the-clock basis.

DEMAND - the rate at which electric energy is delivered to or by a system, part of a system, or piece of equipment, expressed in kilowatts or other suitable unit, at a given instant or averaged over any designated period of time.

DIVERSITY, LOAD - the difference between the peak of coincident and non-coincident demands of two or more individual loads.

ENERGY - that which does or is capable of doing work. It is measured in terms of the work it is capable of doing; electric energy is usually measured in kilowatt-hours.

Firm Energy - electric energy which is intended to have assured availability to the customer to meet all or any agreed upon portion of his load requirements.

Off-peak Energy - electric energy supplied during periods of relatively low system demands as specified by the supplier.

FACTOR

Load Factor - the ratio of the average load over a designated period to the peak-load occurring in that period.

Capacity Factor - the ratio of the average load on a machine or equipment for the period of time considered, to the capacity rating of the machine or equipment.

Plant Factor - the ratio of the average load on the plant for the period of time considered to the aggregate rating of all the generating equipment installed in the plant.

Power Factor - the ratio of kilowatts to kilovolt-amperes.

LOAD - the amount of electric power delivered at a given point.

Base Load - the minimum load in a stated period of time.

Peak Load - the maximum load in a stated period of time.

PLANT (STATION)

Hydroelectric Plant - an electric power plant utilizing falling water for the motive force of its prime movers.

Pumped-Storage Plant - a power plant utilizing an arrangement whereby electric energy is generated for peak load use by utilizing water pumped into a storage reservoir usually during off-peak periods. A pumped-storage plant may also be used to provide reserve generating capacity.

POWER

Firm Power - power intended to have assured availability to the customer to meet all or any agreed upon portion of his load requirements.

RESERVE

Spinning Reserve - generating capacity connected to the bus and ready to take load. It also includes capacity available in generating units which are operating at less than their capability.

THERMAL - a term used to identify a type of electric generating station or power plant, or the capacity or capability thereof, in which the source of energy for the prime mover is heat.

Addendum A

H Y D R O E L E C T R I C   P O W E R   V A L U E

The benefits of power produced by a conventional or pumped-storage hydroelectric project are equivalent to the value of the power to the users as measured by the amount they would be willing to pay for such power. Normally, the cost of power from the most likely alternative source is an appropriate measure of the value of the power produced by a project.

The value of power can be expressed in two components--capacity value and energy value. The capacity value is derived from a determination of the fixed costs of the selected alternative source of supply. The energy value is determined from those costs of the alternative which relate to and vary with its energy output. The fixed costs are those annual costs governed by the investment in generating and transmission facilities, their appropriate financing charges, and certain other operating costs which vary very little with hours of operation. The energy value is determined from the cost of fuel consumed and operation and maintenance costs which vary with energy output. The capacity and energy components are usually expressed in terms of dollars per kilowatt-year and mills per kilowatt-hour, respectively. The capacity component is related to the dependable capacity of the hydroelectric plant and the energy component of the average usuable energy output of the plant.

The value of hydroelectric power can be estimated for either or both of two locations: (1) at-market, i.e., at a load center; or (2) at-site, where power leaves the hydroelectric plant.

The alternative to a hydroelectric project is the most likely power supply source that normally would be selected for addition to the regional power supply if the project is not constructed. At the present time the most likely alternative is a modern thermal-electric generating plant. The proper type of thermal plant alternative is the one which will provide the most economical source of peaking, intermediate, or base load service in the absence of the hydroelectric plant expected to be used for any one of these types of service. No values based on a coal-fired steam-electric power plant were estimated since, under present circumstances, it does not appear that additional plants of this type will be constructed west of the Cascades, after the Centralia Plant is completed.

In estimating power value, consideration must be given to differences in dependability between the project and its alternative. Differences in operating flexibility, service availability and fast loading features which stem from plant characteristics need to be considered. These characteristics include the low speeds and temperatures of the rugged hydro plant machinery in contrast to high speed, high temperature and pressure of high efficiency thermal plants. Usually, consideration of these factors will indicate that a credit to the value of hydroelectric project plant capacity is warranted. Estimates of this credit vary from 5 to 15 percent of the at-market cost per kilowatt of alternative thermal capacity.

Power values derived herein are based on present day (January 1, 1969) price levels, and are applicable to those hydroelectric sources projected to be constructed in the three study periods--1980, 2000, and 2020.

POWER VALUES BASED ON TYPES OF ALTERNATIVE POWER PLANTS

The three types of thermal-electric plants considered appropriate as alternatives to hydroelectric projects with annual capacity factors (ratio of annual average load to the capacity rating of equipment) ranging from 1 to 90 percent are as follows:

Type of Plant	Hydro Plant Capacity Factors (Percent
Gas Turbine	1 to 10
Steam-electric peaking	2.5 to 30
Nuclear-electric	20 to 90

Although each plant has an assigned band of capacity factors, in actual practice not every one of them would be operated over the full band owing to design and operational constraints and economic considerations.

The description of these plants is given in Table A-1. The capital costs include all costs of a modern thermal-electric plant as constructed. Plant designs include features for minimizing production of pollutants and wastes which have adverse effects on the environment.

Table A-2 shows costs of thermal power at the generator bus, at-market and the at-site values of hydroelectric project power for ranges of capacity factors. Power values include a credit of 10 percent to cover the advantages of hydro capacity discussed previously. The estimates of project plant at-site power values were obtained by deducting from the at-market values a hydro plant average Pacific Northwest transmission liability of $2.25 per kilowatt-year, a 4.5 percent capacity loss, and an energy loss which varies with the annual capacity factor.

Costs and values were estimated on both private and public non-Federal construction of the alternatives. Private power costs assume that the financing will be with a money cost of 7 percent. The financing of public non-Federal alternative sources is assumed to be at an interest rate of 4.75 percent. The total annual fixed charge rates for plants, substations, and transmission lines vary not only with the type of financing but also with estimated service lives, interim replacement costs, insurance, and taxes. Values developed for both types of financing permit the evaluation of power benefits at projects which may be constructed to supply either a public or a private market. For a particular hydro project's output, the appropriate value should be the lower of the values shown for the annual capacity factor at which the hydroelectric plant is expected to operate.

In addition, composite at-market and at-site values are shown. They were developed by weighting the private and public non-Federal values on the basis of the present division in Pacific Northwest power supply which is split between public and private approximately 3 to 1. The resultant values permit power benefits to be computed for those projects which are expected to supply a mixed private and public market. Thus, one type of financing is not favored to the exclusion of the other.

Composite at-site values, i.e., with both the capacity and energy components included, are given in mills per kilowatt-hour in Table A-3 and plotted on Figure A-1. Also shown in Table A-3 is a range of capacity factors and corresponding values. The curves and the uniform values are appropriate for estimating at-site power benefits of hydroelectric projects which may supply a mixed private and public non-Federal market as in the Puget Sound, Willamette River Basin, or Columbia-North Pacific areas of the Pacific Northwest, but excluding the predominantly private system market of the middle and upper Snake River Basin. These data are used in developing the benefits shown in Tables IV-1 and IV-2 of the main text.

FEDERAL FINANCED RIVER DEVELOPMENT PROJECTS

The evaluation of power benefits at Federal river development projects is guided by Senate Document No. 97 which was prepared under the direction of the President's Water Resources Council. The Document provides that where benefits are measured by alternative costs, as is the case for power, the alternative cost will be based on the alternative means that would most likely be utilized to provide equivalent product or services. In the Pacific Northwest where no Federally financed thermal plants are planned, this most likely alternative has been considered to be a composite of private and public non-Federal thermal plants described in the preceding section.

The Document provides, however, that in formulating projects, benefits and costs shall be expressed in comparable quantitative economic terms to the fullest extent possible. Generation costs at a Federal hydroelectric project in the Pacific Northwest must therefore be less than power generated at a Federally-financed thermal plant if the project is to be proposed for construction.

Addendum A (Cont'd.)

Table A-1

Pacific Northwest
Description of Thermal-electric Plants
(Alternatives to Hydroelectric Plants
With Specific Ranges of Capacity Factors,
January 1969 Price Levels)

Item	Type of Plant: Gas-turbine Peaking	Steam electric Peaking	Nuclear-electric
Capacity Factor Range in Percent	1 - 10	2.5 - 40	20 - 90
Total Capacity, MW	640	800	2,000
Units: Number	4	2	2
Size, MW	160	400	1,000
Capital Cost, $/KW	77	82	159
Fuel: Type	Oil	Oil	Nuclear
Average Fuel Cost, $/Million Btu	0.88	0.452	0.12 1/
Average Net Heat Rate, Btu/KWH	16,500	11,078	10,500 2/

1/ Equivalent to a nuclear fuel cost of 1.23 mills/kwh (5 fuel cycle average) and a net plant heat rate of 10,500 Btu/kwh (with turbine rating at design back pressure of 1.8" - 2.0" Hg).

2/ For comparison only with conventional steam-electric plants. Nuclear plant efficiency in Btu/kwh not normally specified since it is not relevant in computations of fuel energy costs.

Source: Federal Power Commission.

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THE WILLAMETTE BASIN COMPREHENSIVE STUDY OF WATER AND RELATED L--ETC(U)
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Addendum A (Cont'd.)

Table A-2

Pacific Northwest
Values of Hydroelectric Plant Power
Based on Unit Annual Costs of Power from
Alternative Thermal Sources
(January 1969 Price Levels)

Gas-turbine Peaking Plant					
	Capacity			Composite Values	
Annual Capacity Factor (Percent)	Private Financing ($/KW-Yr)	Public Non-Federal Financing ($/KW-Yr)	Energy (Mills/KWH)	Capacity ($/KW-Year)	Energy (Mills/KWH)
Cost of Power at Thermal Plant Generator Bus					
1.0	8.71	6.08	20.88	-	-
2.5	8.78	6.14	17.49	-	-
5.0	8.86	6.19	16.10	-	-
7.5	8.94	6.25	15.65	-	-
10.0	9.01	6.30	15.42	-	-
Value of Hydroelectric Power at Market					
1.0	11.91	8.45	20.96	9.32	20.96
2.5	11.99	8.51	17.57	9.38	17.57
5.0	12.08	8.57	16.19	9.45	16.19
7.5	12.08	8.64	15.75	9.52	15.75
10.0	12.24	8.69	15.52	9.58	15.52
Value of Hydroelectric Power at Site					
1.0	8.80	5.49	20.77	6.32	20.77
2.5	8.87	5.55	17.38	6.38	17.38
5.0	8.96	5.61	15.99	6.45	15.99
7.5	9.04	5.67	15.52	6.51	15.52
10.0	9.11	5.72	15.27	6.57	15.27

Source: Federal Power Commission.

Addendum A (Cont'd.)

Table A-2

Pacific Northwest
Values of Hydroelectric Plant Power
Based on Unit Annual Costs of Power from
Alternative Thermal Sources
(January 1969 Price Levels)

Oil-fired Steam-electric Peaking Plant					
Annual Capacity Factor (Percent)	Capacity: Private Financing ($/KW-Yr)	Capacity: Public Non-Federal Financing ($/KW-Yr)	Energy (Mills/KWH)	Composite Values: Capacity ($/KW-Year)	Composite Values: Energy (Mills/KWH)
Cost of Power at Thermal Plant Generator Bus					
2.5	10.43	7.63	5.83	-	-
5.0	10.90	8.10	4.71	-	-
7.5	11.33	8.52	4.31	-	-
10.0	11.65	8.83	4.10	-	-
15.0	12.22	9.38	3.91	-	-
20.0	12.66	9.81	3.80	-	-
25.0	13.01	10.15	3.76	-	-
30.0	13.40	10.52	3.80	-	-
Value of Hydroelectric Power at Market					
2.5	14.76	10.77	5.88	11.77	5.88
5.0	15.30	11.32	4.76	12.32	4.76
7.5	15.79	11.79	4.36	12.79	4.36
10.0	16.16	12.16	4.15	13.16	4.15
15.0	16.81	12.78	3.97	13.79	3.97
20.0	17.31	13.28	3.87	14.29	3.87
25.0	17.71	13.66	3.83	14.67	3.83
30.0	18.15	14.08	3.88	15.10	3.88
Value of Hydroelectric Power at Site					
2.5	11.52	7.71	5.82	8.66	5.82
5.0	12.03	8.23	4.70	9.18	4.70
7.5	12.50	8.68	4.30	9.64	4.30
10.0	12.85	9.03	4.08	9.98	4.08
15.0	13.48	9.63	3.90	10.59	3.90
20.0	13.95	10.10	3.79	11.07	3.79
25.0	14.33	10.47	3.75	11.43	3.75
30.0	14.75	10.87	3.79	11.84	3.79

Source: Federal Power Commission.

Addendum A (Cont'd.)

Table A-2

Pacific Northwest
Values of Hydroelectric Plant Power
Based on Unit Annual Costs of Power from
Alternative Thermal Sources
(January 1969 Price Levels)

Nuclear-Electric Plant					
	Capacity			Composite Values	
Annual Capacity Factor (Percent)	Private Financing ($/KW-Yr)	Public Non-Federal Financing ($/KW-Yr)	Energy (Mills/KWH)	Capacity ($/KW-Year)	Energy (Mills/KWH)
Cost of Power at Thermal Plant Generator Bus					
20	22.86	16.75	1.44	-	-
30	22.88	16.77	1.37	-	-
40	22.93	16.82	1.34	-	-
50	22.97	16.86	1.32	-	-
60	23.05	16.94	1.31	-	-
70	23.10	16.99	1.30	-	-
80	23.20	17.09	1.29	-	-
90	23.35	17.24	1.29	-	-
Value of Hydroelectric Power at Market					
20	29.08	21.38	1.46	23.31	1.46
30	29.11	21.41	1.39	23.34	1.39
40	29.16	21.46	1.36	23.39	1.36
50	29.21	21.52	1.34	23.44	1.34
60	29.29	21.60	1.33	23.52	1.33
70	29.35	21.66	1.33	23.58	1.33
80	29.46	21.77	1.32	23.69	1.32
90	29.63	21.93	1.32	23.86	1.32
Value of Hydroelectric Power at Site					
20	25.19	17.84	1.43	19.68	1.43
30	25.22	17.87	1.36	19.71	1.36
40	25.27	17.92	1.32	19.76	1.32
50	25.32	17.97	1.30	19.81	1.30
60	25.39	18.05	1.29	19.89	1.29
70	25.45	18.11	1.28	19.94	1.28
80	25.56	18.21	1.27	20.05	1.27
90	25.72	18.36	1.27	20.20	1.27

Source: Federal Power Commission.

Addendum A (Cont'd.)

Table A-3

Pacific Northwest
Hydroelectric Plant Power Values At Site 1/
(January 1969 Price Levels)

Thermal Source (Hydro Plant Alternative)	Annual Capacity Factor (Percent)	Total Value 2/ (Mills/KWH)
Gas Turbine	1.0	92.92
	2.5	46.51
	5.0	30.72
	7.5	25.43
	10.0	22.77
Steam-electric (Peaking)	2.5	45.36
	5.0	25.66
	7.5	18.97
	10.0	15.47
	15.0	11.96
	20.0	10.11
	25.0	8.97
	30.0	8.30
Nuclear-electric	20.0	12.66
	30.0	8.86
	40.0	6.96
	50.0	5.82
	60.0	5.07
	70.0	4.53
	80.0	4.13
	90.0	3.83

Annual Capacity Factor (Percent)	Uniform Value 3/ (Mills/KWH)
1.0	92.90
2.5	45.40
5.0	25.70
7.5	19.00
10.0	15.50
15.0	12.00
20.0	10.10
25.0	9.00
30.0	8.30
40.0	7.00
50.0	5.80
70.0	4.50
90.0	3.80

1/ Appropriate for determining power benefits of hydroelectric projects which may supply a mixed private and public market.

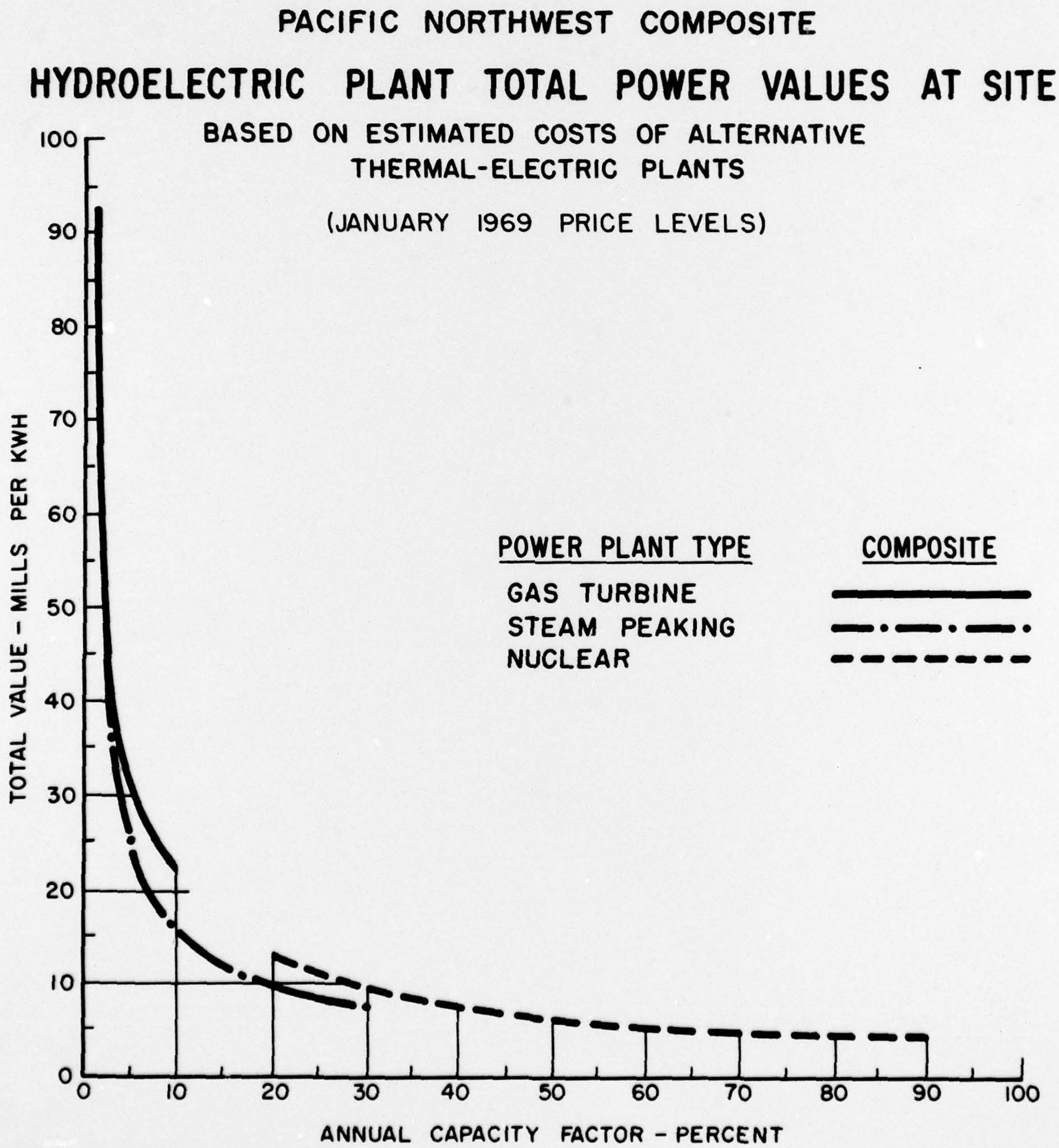
2/ Total values derived from composite at-site capacity and energy components of value given in Table A-2.

3/ Taken from curves shown on Figure A-1.

Source: Federal Power Commission.

Addendum A (Cont'd.)

Figure A-1



Addendum B

PUMPED-STORAGE SITE SELECTION CRITERIA

In selecting the sites to be included in the pumped-storage inventory, the following factors were taken into consideration: (1) Source of energy, (2) Topography, (3) Operating pattern, (4) Plant size and characteristics, (5) Reservoir size and characteristics, and (6) Penstock size and characteristics.

SOURCE OF ENERGY

It was assumed that low-cost, off-peak energy would be available from thermal plants, and that these plants would be located in or near the Willamette Basin, thus keeping transmission losses from the thermal plants to the pumped-storage plants relatively small.

TOPOGRAPHY

The physical characteristics of a site have a direct bearing on the cost of development. To minimize costs, sites were sought which had fairly high heads (600 feet or more), short penstock requirements, and small embankment requirements. With higher heads, it is possible to reduce costs of the pump-turbine, motor-generator equipment, the diameter of the penstocks, and the size of the reservoirs.

OPERATING PATTERN

The operating pattern of a pumped-storage plant is governed by three inter-related factors: (1) the system load shape, (2) the relative capabilities and economies of the other types of power plants available (which determines what part of the load each will carry), and (3) the amount of off-peak thermal energy available for pumping. These factors will change as time progresses, with the situation becoming increasingly favorable for the utilization of pumped-storage as thermal power assumes a larger part of the base load.

It is assumed that the pumped-storage plants will operate on a weekly cycle, generating during the weekday peak hours and pumping during the off-peak hours at night and on weekends (See Figure IV-2 in main text). Studies are now underway which will provide an indication of how pumped-storage will best fit into the future load pattern. Pending the results of these studies, an arbitrary decision was made on the amount of storage to be provided in developing data for project comparison purposes. Sufficient storage was provided to permit generation for 8 hours at rated capacity. An example of one loading condition is illustrated by Figure IV-2. In this example, the pumped-storage plant is required to operate at full capacity for only a short period each weekday afternoon. For most of the generating periods, the plant is operating at less than rated capacity. Thus, the plant is generating the equivalent of approximately 5 hours at rated capacity each weekday. The balance of the storage is used for carry-over of weekend storage until it is required later in the week. The night-time off-peak pumping energy, together with the storage carried over from weekend pumping, is sufficient to provide the storage required to meet the daily peak generation through the week. Additional flexibility could be attained at most sites by increasing the storage to allow more carry-over of weekend pumping. If 8 hours of generation at full capacity each weekday were required for pumped-storage power instead of the equivalent of 5 hours of generation at rated capacity each weekday as mentioned above, almost twice the reservoir storage capacity would be required. This increase in reservoir capacity would increase investment costs and possibly eliminate some of the potential sites. The amount of storage most appropriate for each plant will be determined at the time of its design. This additional capacity could be developed at most of the sites inventoried.

PLANT SIZE AND CHARACTERISTICS

All sites evaluated are suitable for plants having a capacity of at least 1,000 MW. This minimum size was selected for two reasons. First, the present trend in pumped-storage construction is toward larger plants to reduce unit costs. Secondly, this made it possible to eliminate the numerous small sites and keep the number of sites under consideration to a workable number. In evaluating the better sites, an attempt was made to derive costs for several plant sizes, up to the maximum feasible installation. The factor controlling the maximum installation was the amount of usable reservoir storage attainable at the site coupled with drawdown limitation.

The heads available at most of the sites permit the use of reversible Francis pump-turbines. Although present technology limits the design of reversible units to heads of about 1,600 feet, the indications are that reversible units with heads as great as 2,000 feet can be developed by the time these projects would be needed, sometime after 1990. There are a number of sites in the Willamette Basin having heads even higher than 2,000 feet. Based on present technology, these sites would require separate pumps and impulse turbines. The size of the units selected were the largest feasible for a given installation.

RESERVOIR SIZE AND CHARACTERISTICS

Reservoir size is governed by the usable storage requirements, the allowable drawdown, and, in the case of the lower reservoirs, the amount of pump-turbine submergence required. The usable storage requirements are a function of the plant capacity and available hydrostatic head (see Figure B-1). To keep embankment costs at a minimum, very little dead storage would normally be provided. Hence, the drawdowns necessary to obtain the required usable storage are sometimes quite large. At some sites, however, where it is anticipated that there would be public access to the reservoir, drawdowns are minimized in the interest of safety and aesthetics. To do this, it is necessary either to limit the generating capacity of the site or to increase the dead storage.

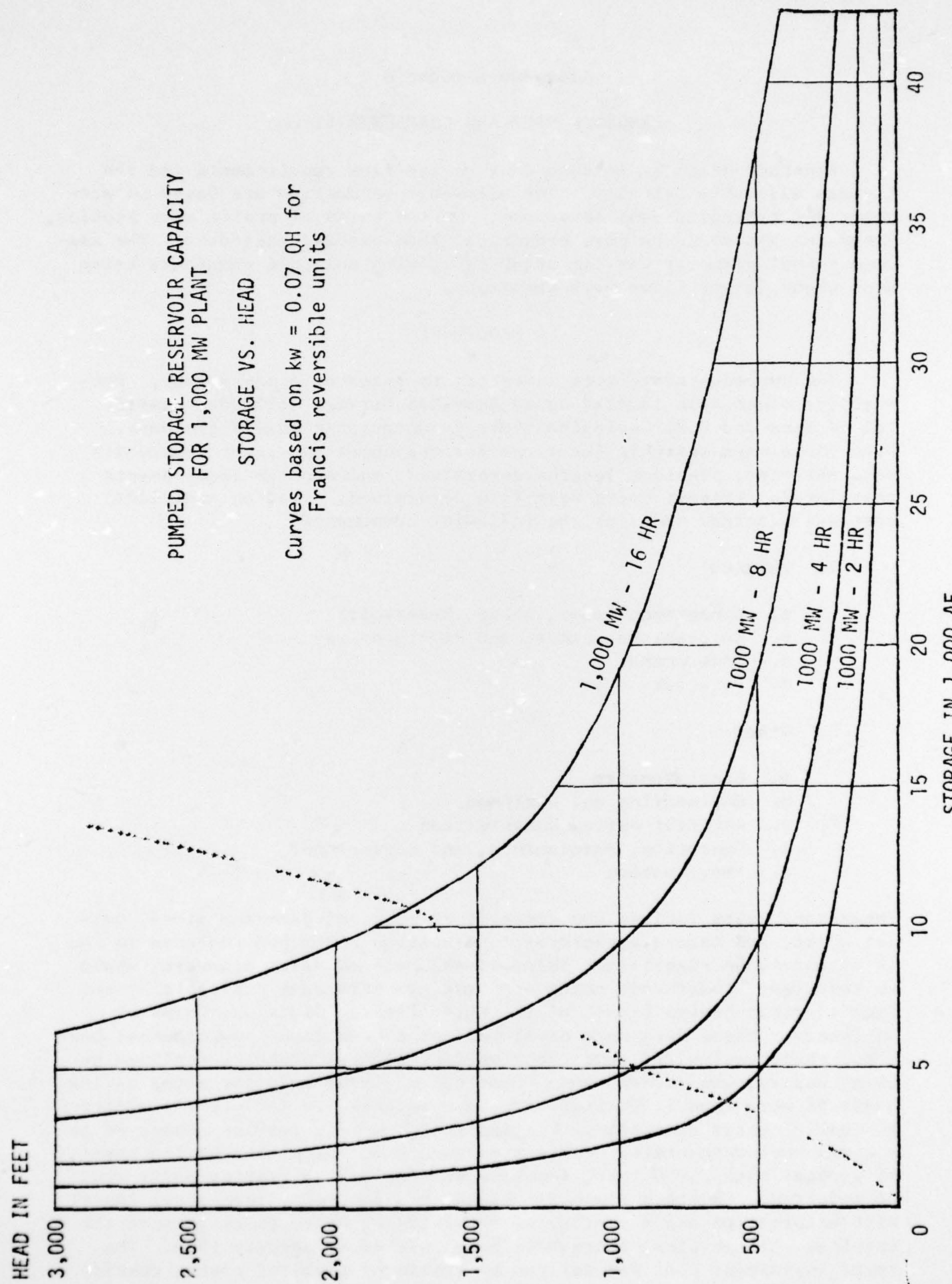


Figure B-1 - Pumped Storage Reservoir Capacity

Addendum B (Cont'd.)

PENSTOCK SIZE AND CHARACTERISTICS

Penstock diameter is dependent on the flow requirements and the maximum allowable velocity. The allowable velocities are based on economic and hydraulic considerations. On the basis of preliminary studies, lined tunnels would be more economical than exposed penstocks. The maximum tunnel diameter was set at 40 feet, with multiple penstocks being used where larger flows were required.

PROCEDURE

The pumped-storage site inventory is based on a map survey. Prospective sites were located using Army Map Service 1:250,000 plastic relief maps and U.S. Geological Survey topographic quadrangle maps. From these maps suitable locations for the upper and lower reservoirs were selected, penstock lengths determined, and storage requirements calculated. Project costs were then determined, based on individual cost calculations made for the following components:

1. Physical
   a. Embankment (Dams, Dikes, Reservoirs)
   b. Relocations, Lands, and Rights-of-way
   c. Powerhouse
   d. Penstock
2. Other
   a. Contingencies
   b. Engineering and Overhead
   c. Interest during Construction
   d. Operation, Maintenance, and Replacement
   e. Amortization

Embankment costs include the costs of earthfilled dams and dikes, outlet works, and intake structures. Relocation costs are included in the total only when significant relocations, such as major highways, would be required. Powerhouse costs are based on data made available by the Hydroelectric Design Branch of the North Pacific Division, Corps of Engineers. These data were developed for conventional powerhouses; however, where geological conditions permit, savings might be realized by using underground powerhouses. Cost calculations made for sites having heads of more than 2,000 feet have been adjusted to reflect the additional cost of units consisting of a separate pump and turbine connected to a common motor-generator. It was assumed that for plants having heads of greater than 2,000 feet, separate pumping and generating units would be required. Penstock costs are based on a concrete lined power tunnel with bifurcation and a section of steel lining prior to entry into the turbine. All physical costs have been indexed to January 1968. The total investment cost was derived by combining physical costs, contingencies of 25 percent, engineering and overhead (including contract administration, supervision, and inspection) of 12 percent, and interest during construction of 4-5/8 percent over a 4-year period. Since it was apparent that there would be many sites available which could be developed at less than $150 per kilowatt, projects having investment costs of greater than $150 per kilowatt were eliminated from further consideration.

In addition to the investment costs, annual capacity costs were computed, which include amortization of the investment costs over 50 years at 4-5/8 percent interest and estimated operation, maintenance, and replacement costs.

The resulting pumped-storage project costs, listed on Table IV-3 are pure capacity costs. They do not include the cost of pumping energy and may not be compared with alternative peaking sources without the addition of a pumping energy cost. That cost, however, is not site-related. It will be determined by the part of the peak load to be carried by the pumped-storage project and by the source of the pumping energy. Furthermore, in actual system operation, different pumped-storage plants will probably operate at different load factors and will therefore have different return energy requirements. When specific load factor and energy value data become available, the annual capacity costs listed in Table IV-3 can be used as a basis for computing total annual costs for the individual projects.

As a result of the preliminary site selection studies, certain general observations can be made with regard to the effect of the various site characteristics on capacity costs. The unit cost declines markedly as the head increases as is illustrated by Figure B-2. The cost increases significantly as the distance between the upper and lower pool increases. This increase is much more pronounced with low head plants than with high head plants as is illustrated by Figure B-3. The relationship of component costs to the total investment cost is shown by the following table.

Major Components	Percent of Investment Cost
Dams, Reservoirs, & Relocations	7
Powerhouse	38
Penstocks	20
Contingencies & Other*	35

* Includes allowances for contingencies, engineering and design, supervision and inspection, overhead, and interest during construction.

As shown in the above tabulation, the powerhouse and penstock costs constitute the majority of the project physical costs. Since the powerhouse unit costs are dependent largely on head, it is apparent that the better sites would generally be those having high heads and relatively short penstocks.

Figure B-2 - Investment Cost vs. Head for 1,000 MW Pumped Storage Plant

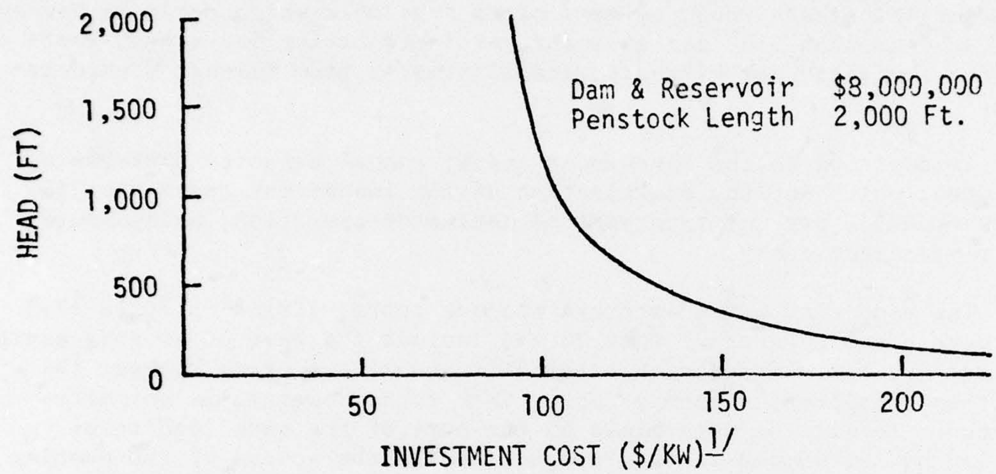
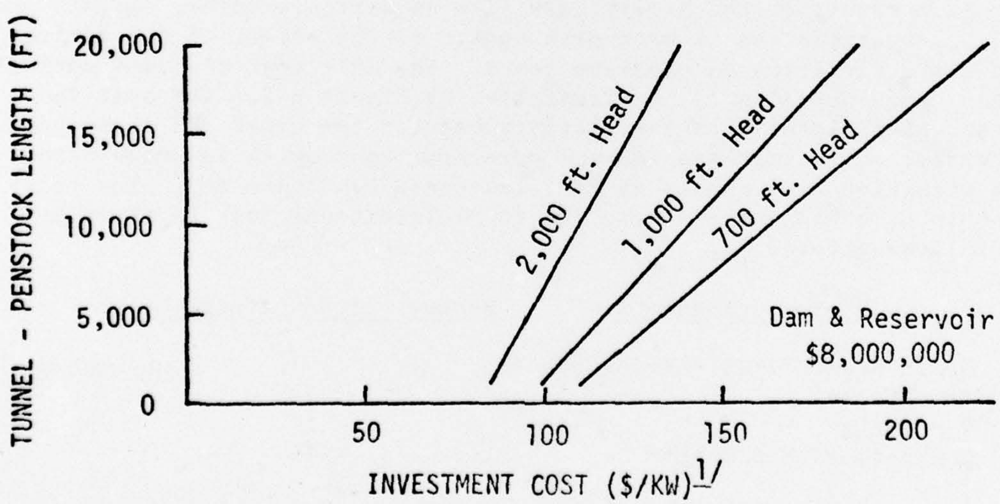


Figure B-3 - Investment Cost vs. Penstock Length for 1,000 MW Pumped Storage Plant



1/ Includes interest during construction and contingencies.