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Assessment of the Effects of Climate Change on Federal Hydropower

An Assessment Prepared in Response to Section 9505(c) of the SECURE Water Act of 2009

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Environmental Sciences Division

ASSESSMENT OF THE EFFECTS OF CLIMATE CHANGE ON FEDERAL HYDROPOWER

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ABSTRACT

As directed by Congress in Section 9505 of the SECURE Water Act of 2009 (Public Law 111-11), the US Department of Energy (DOE), in consultation with the federal Power Marketing Administrations (PMAs) and other federal agencies, including federal dam owners, has prepared a comprehensive assessment examining the effects of climate change on water available for hydropower at federal facilities and on the marketing of power from these federal facilities. This Oak Ridge National Laboratory TM report, referred to as the "9505 Assessment," describes the technical basis for the report to Congress that was called for in the SECURE Water Act. The 9505 Assessment included (1) a historical analysis of the sensitivity of federal hydropower operations to climate variables, (2) a climate modeling analysis that projected climate conditions and impacts to hydropower into the future, and (3) a literature review of other related climate studies for comparison to the 9505 modeling results. The assessment used consistent methods across all PMA regions, to enable nationwide policy analysis.

Federal hydropower is an important part of the national renewable energy portfolio, because it accounts for approximately half of the United States' installed conventional hydropower capacity. The 132 federal hydropower projects that were studied have produced an annual average of 120.6 billion kWh over the period from 1971 to 2008. For the first time, the 9505 Assessment quantified how this federal power responds to water availability, as measured by runoff aggregated over upstream watersheds. A series of climate simulation models were then used to make projections of regional climate conditions for 30 years into the future in 18 assessment areas and 4 regions across the country, 1 region for each of the PMAs. Assessment variables included annual and seasonal estimates of air temperature, precipitation, runoff, frequency of occurrence of water year types, and an index of drought severity. Results show how global climate changes will affect runoff and power generation, but the patterns of these changes are both spatially and temporally complex. Aggregated to a national level, the median change in federal hydropower is between 1 and 2 billion kWh/year, with a model uncertainty range of ± 9 billion kWh/year. Although those estimates are similar to the recently observed range of generation from federal hydropower and may appear to be manageable, extreme water years, both wet and dry, will pose significantly greater challenges to water managers.

The 9505 Assessment gives federal hydropower administrators the opportunity to plan their operational or contracting responses to these changes in order to minimize any negative impacts on future hydropower generation, water quality, and water availability for other uses. This effort will promote better understanding of the sensitivity of federal power plants to water availability and will provide a basis for planning future actions that will enable adaptation to climate variability and change. Future assessments of climate impacts are anticipated under Section 9505—these can be improved by incorporating improved climate models and data that will become available soon, by closer examination of extreme events and longer-term change, and by addressing the interactions among hydropower and other water uses at a more project-specific level.

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This assessment report was completed in September 2011 and was the basis for the DOE Report to Congress on *Effects of Climate Change on Federal Hydropower*. Minor editorial changes have been made in specific sections since September 2011, but the main substance remains unchanged. Public release was delayed until Congress had received its report.

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ABBREVIATIONS, ACRONYMS, AND INITIALISMS

20C3M	20th Century Control Run
ACF	Apalachicola-Chattahoochee-Flint
ACT	Alabama-Coosa-Tallapoosa
AOGCM	atmosphere-ocean general circulation model
AOP	Annual Operating Plan
BCSD	bias corrected and spatial downscaled
BDCP	Bay Delta Conservation Plan
Bonneville	Bonneville Power Administration
BPA	Bonneville Power Administration
CBCCSP	Columbia Basin Climate Change Scenarios Project
CCAWWG	Climate Change and Water Working Group
CCSM3	Community Climate System Model, Version 3
CCSP	US Climate Change Science Program
CI	confidence interval
CMIP3	Coupled Model Intercomparison Project, Phase 3
CRBWSDST	Colorado River Basin Water Supply and Demand Study
CRC	cost recovery charge
CRCM	Canadian Regional Climate Model
CRITFC	Columbia River Inter-Tribal Fish Commission
CRSP	Colorado River Storage Project
CRT	Columbia River Treaty
CVP	Central Valley Project
CVPIA	Central Valley Project Improvement Act
DAAC	Distributed Active Archive Center
DOE	Department of Energy
DOI	US Department of Interior
DSI	direct service industrial
EIA	US Energy Information Administration
EPA	US Environmental Protection Agency
FCRPS	Federal Columbia River Power System
FERC	Federal Energy Regulatory Commission
FES	firm electric service
FPS	firm power products and services rates
ft amsl	feet above mean sea level
G	hydropower generation

GAO	General Accounting Office
GCM	General Circulation Model
GHG	greenhouse gas
GTOPO30	global 30 arc second evaluation data
GW	gigawatt
HCDN	Hydroclimatic Data Network
HLH	heavy load hours
HMI	Hydropower Modernization Initiative
HUC	hydrologic unit code
HydroAMP	Hydropower Asset Management Partnership
IBWC	International Boundary and Water Commission
IGBP	International Geosphere-Biosphere Programme
IJC	International Joint Commission
IOUs	investor-owned utilities
IP	industrial firm power rate
IPCC	Intergovernmental Panel on Climate Change
kWh	kilowatt-hour
LAP	Loveland Area Projects
LLH	light load hours
M&I	municipal and industrial, as in water use
MODIS	Moderate Resolution Imaging Spectroradiometer
MW	megawatt
MWh	megawatt-hour
NARCCAP	North American Regional Climate Change Assessment Program
NASA	National Aeronautics and Space Administration
NCDC	National Climatic Data Center
NHAAP	National Hydropower Asset Assessment Project
NHD	National Hydrography Dataset
NOAA	National Oceanographic and Atmospheric Administration
NPPCC	Northwest Power Planning and Conservation Council
NR	new resource firm power rate
NRCS	National Resources Conservation Service
O&M	operations and maintenance
OATT	Open Access Transmission Tariff
OMB	Office of Management and Budget
ORNL	Oak Ridge National Laboratory
P	precipitation
PCMDI	Program for Climate Model Diagnosis and Intercomparison
PF	priority firm power rate

P. L.	Public Law
P-SMBP	Pick-Sloan Missouri Basin Program
PMA	Power Marketing Administration
PNW	Pacific Northwest
PRISM	Parameter-elevation Regressions on Independent Slopes Model
PRS	Power Repayment Study
R	runoff
RCM	regional climate model
Reclamation	Department of Interior's Bureau of Reclamation
RegCM3	Regional Climate Model, Version 3
RMJOC	River Management Joint Operating Committee
RRS	revenue requirement studies
SEPA	Southeastern Power Administration
SLIP	Salt Lake Integrated Projects
Southeastern	Southeastern Power Administration
Southwestern	Southwestern Power Administration
SPP	Southwest Power Pool
SRDEC	Sam Rayburn Dam Electric Cooperative
SRMPA	Sam Rayburn Municipal Power Agency
SWA	SECURE Water Act
SWPA	Southwestern Power Administration
TVA	Tennessee Valley Authority
TWh	terawatt hour, equal to one billion kWh
USACE	US Army Corps of Engineers
USGS	US Geological Survey
VIC	Variable Infiltration Capacity
WAPA	Western Area Power Administration
WBD	Watershed Boundary Dataset
WCRP	World Climate Research Program
Western	Western Area Power Administration

EXECUTIVE SUMMARY

The SECURE Water Act (SWA) of 2009 was signed into law on March 30, 2009, as part of the Omnibus Public Lands Management Act (Public Law 111-11). SWA authorized the Department of Energy (DOE) to analyze and assess the potential impacts that climate change may have on the hydrologic cycle that provides water for communities, economic growth, and protection of ecosystems in the western states and other parts of the United States. Under Section 9505(c) of the Act, DOE was directed to prepare a report to Congress presenting its assessment of the effects of climate change impacts on federal hydropower generation resources in the United States. This Oak Ridge National Laboratory (ORNL) TM report, referred to as the "9505 Assessment," is the technical basis for DOE's Report to Congress. The assessment report briefly describes and summarizes the overall study approach, methods, and results for the Section 9505 Assessment. The required Report to Congress will be a separate summary of this 9505 Assessment report and will be transmitted to Congress by DOE.

Federal hydropower projects are owned and operated by the US Army Corps of Engineers (USACE), US Bureau of Reclamation (Reclamation), International Boundary and Water Commission (IBWC), or Tennessee Valley Authority (TVA). The power produced at these projects is sold and distributed by Power Marketing Administrations (PMAs), which are part of DOE. Since TVA is not a PMA, nor is its power marketed by the Southeastern Power Administration (SEPA or Southeastern), electricity from TVA hydropower projects is not included in this assessment. Therefore, the scope of this report is limited to the hydropower projects that are operated by the USACE, Reclamation, and IBWC.

The USACE operates 75 federal hydropower plants with a total rated capacity of 21,500 MW in 16 states, from Washington to Georgia. The oldest USACE hydropower facility is at Bonneville Dam, on the lower Columbia River, which came on line in 1938. The most recent USACE facility is the RD Willis project, which came on line in 1989.

Reclamation owns and operates 82 power plants in 11 western states, but power from only 58 of those is marketed through a PMA. The oldest Reclamation facility is the Theodore Roosevelt Dam on the Salt River in Arizona, which came on line in 1909. The largest Reclamation facility is the Grand Coulee Dam on the Columbia River in Washington. Grand Coulee Dam is among the top 10 largest dams in the world and has an installed capacity in excess of 6.9 GW.

IBWC owns and operates two small hydropower projects (Amistad and Falson) on the Rio Grande River with a total capacity of 98 MW.

PMAs are federally owned nonprofit organizations with the mission of marketing power produced at federal multipurpose dams. According to the Flood Control Act of 1944, PMAs are to provide electricity "at the lowest possible rates consistent with sound business practices." PMAs receive some appropriations from the US Treasury, which they use to help fulfill their missions. PMA rates are cost-based (selling primarily at the wholesale level) and are generally lower than the profit-based rates charged by investor-owned utilities.

There are four PMAs: Bonneville Power Administration (BPA or Bonneville), Western Area Power Administration (WAPA or Western), Southwestern Power Administration (SWPA or Southwestern), and SEPA. In terms of marketed hydroelectric capacity and annual generation, Bonneville is the largest PMA; however, in terms of total area served, Western is the largest. Each PMA region is discussed below.

The 9505 Assessment approach for this report was designed to provide a consistent and quantitative analysis of potential climate change effects across all four PMA regions, enabling inter-regional comparisons at a national level. The 9505 Assessment required the integration of a large number of different types of data that have not been used together previously (see Table ES-1). The data included hydropower project characteristics, generation records, observed hydrology and meteorology data, watershed and land surface data, and model data from a series of different simulation models.

Table ES-1. Data sources used in the 9505 Assessment

Subject	Data source	Reference
Hydropower project characteristics	National Hydropower Asset Assessment Program, ORNL	Hadjerioua et al., 2011
	Form 860 Database, EIA	
	National Inventory of Dams, USACE	
	Hydropower Asset Management Partnership, Reclamation/Hydro-Québec/ USACE/Bonneville	
Hydropower generation	From 906, 920, and 923 database, EIA	
	Bureau of Reclamation	
	USACE	
	DOE Power Marketing Administrations	
Observed runoff and streamflow	WaterWatch Program, USGS	Brakebill et al., 2011
	HYDAT database, Environment Canada	
Observed temperature and precipitation	PRISM Climate Group, Oregon State University	Daly et al., 2002; Willmott and Matsuura, 1995
	University of Delaware Air Temperature and Precipitation	
Watershed boundary	Watershed Boundary Dataset, NRCS	USGS and USDA-NRCS (2009)
	National Hydrography Dataset, USGS/EPA	
Topography	Global 30 arc second elevation data (GTOPO30), USGS	
Land cover	Moderate Resolution Imaging Spectroradiometer (MODIS), NASA	
General circulation model (GCM)	Community Climate System Model version 3 (CCSM3)	Collins et al., 2006
Regional climate model (RCM)	Abdues Salam Institute for Theoretical Physics Regional Climate Model version 3 (RegCM3)	Pal et al., 2007
Hydrologic model	Variability Infiltration Capacity model	Maurer et al., 2002

USACE = US Army Corps of Engineers; EIA = Energy Information Administration; USGS = US Geological Survey; NRCS = National Resources Conservation Service; USDA = US Department of Agriculture; NASA = National Aeronautics and Space Administration

ASSESSMENT APPROACH

This assessment does not report on individual power plants and watersheds; instead, hydropower projects are aggregated into larger areas corresponding to power systems and river basins. Four analysis areas are distinguished for Bonneville, Southwestern, and Southeastern, and six areas are distinguished for Western (Figure ES-1).

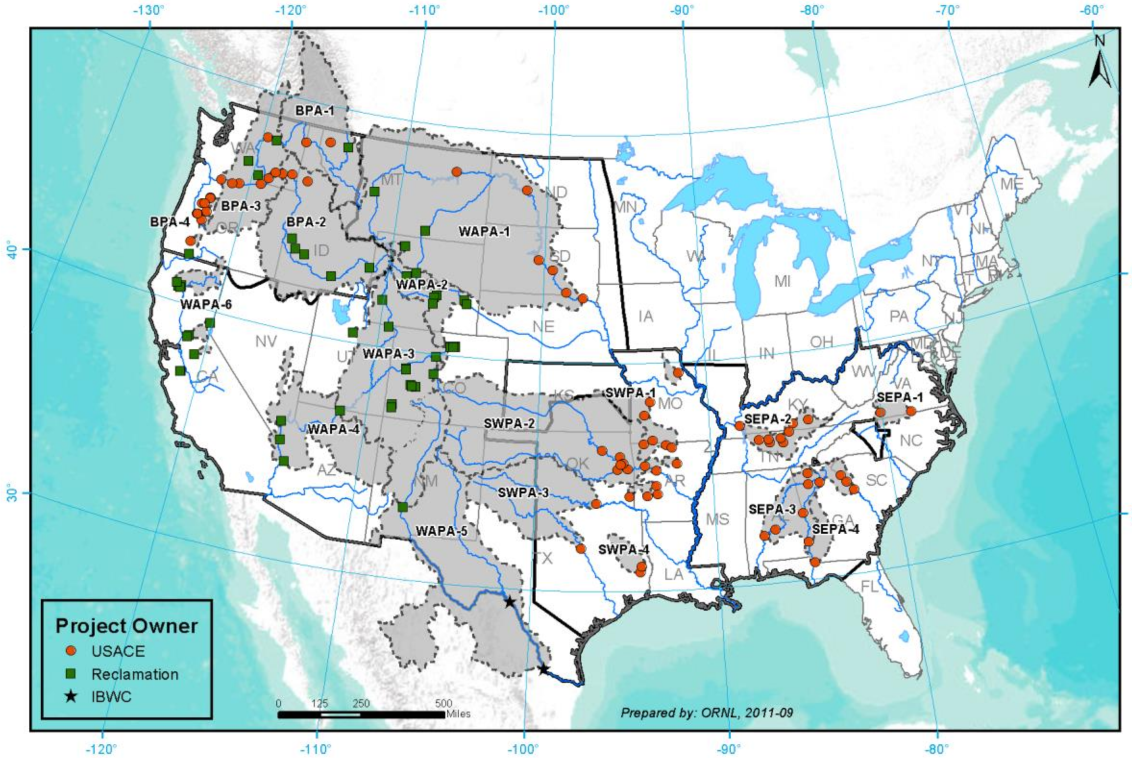


Figure ES-1. Federal hydropower projects, regions, and assessment areas evaluated in the 9505 Assessment.

The 9505 Assessment combined (1) a historical analysis of the sensitivity of observed hydropower generation to climate variables with (2) a series of hydroclimate simulation models that projected climate conditions and impacts to hydropower into the future. The historical analysis indicated that annual generation (G) at federal hydropower projects is highly correlated with annual runoff (R) in upstream watersheds. These "R v G" relationships were constructed from the most recent 20 year period of generation data, so they are representative of current operating policies and procedures and current hydropower equipment. In some river basins, multi-year totals of runoff produced the best correlations with annual generation, reflecting the importance of surface water storage in reservoirs to compensate for low-water years.

The climate simulation models used to project future conditions included one general circulation model, one regional climate model for dynamical downscaling, quantile-based bias correction techniques to align modeled results with observed data, and a macro-scale hydrologic model to integrate the multivariate effects of future temperature and precipitation into runoff estimates. Estimates of future annual runoff were not routed down through river networks to individual projects, but rather were spatially aggregated across the full watersheds contributing water to areas of analysis (i.e., groups of hydropower projects) in a form comparable to the runoff used in empirical R v G relationships. Only one emission scenario was used to drive future climate projections. A five-member ensemble of simulation results was used to estimate the range of model uncertainty, and the median ensemble member was used to represent the central tendencies for future conditions. Impacts to federal hydropower were estimated with the empirical R v G regressions.

Future climate conditions and impacts to federal hydropower were modeled for two time periods: a near-term period of 2010–2024 and a mid-term period of 2025–2039. The 9505 Assessment did not attempt to project climate change impacts to hydropower beyond 30 years into the future, because there are too many other nonclimate issues that will interact with climate effects and that depend on policy decisions yet to be made. Three of these nonclimate factors are (1) the type and efficiency of hydropower equipment as it is replaced and upgraded over time, (2) the reallocation of water storage in federal reservoirs to nonpower uses, and (3) changing water management requirements for environmental protection and restoration.

The 9505 Assessment estimated potential changes to the following climate variables for 30 years into the future: air temperature, precipitation, annual and seasonal runoff, frequency of different water year types (dry=lower 20th percentile, normal=middle 60th percentile, and wet=upper 20th percentile), and intensity of low-flow periods relative to current conditions. The following summary statements are the results of the 9505 Assessment in the river basins that provide water for federal hydropower projects.

Significant increases in temperature were projected in all regions and time periods, in the range of +2 to +4°F between now and 2039, relative to current conditions. In all regions, the projected temperature change is greater for the mid-term period (2025–2039) than for the near-term (2010–2024). Much more variable trends were projected for precipitation and runoff, both spatially and temporally. Examples of the projected spatial variability in runoff, the primary measure of water availability, are shown in Figure ES-2.

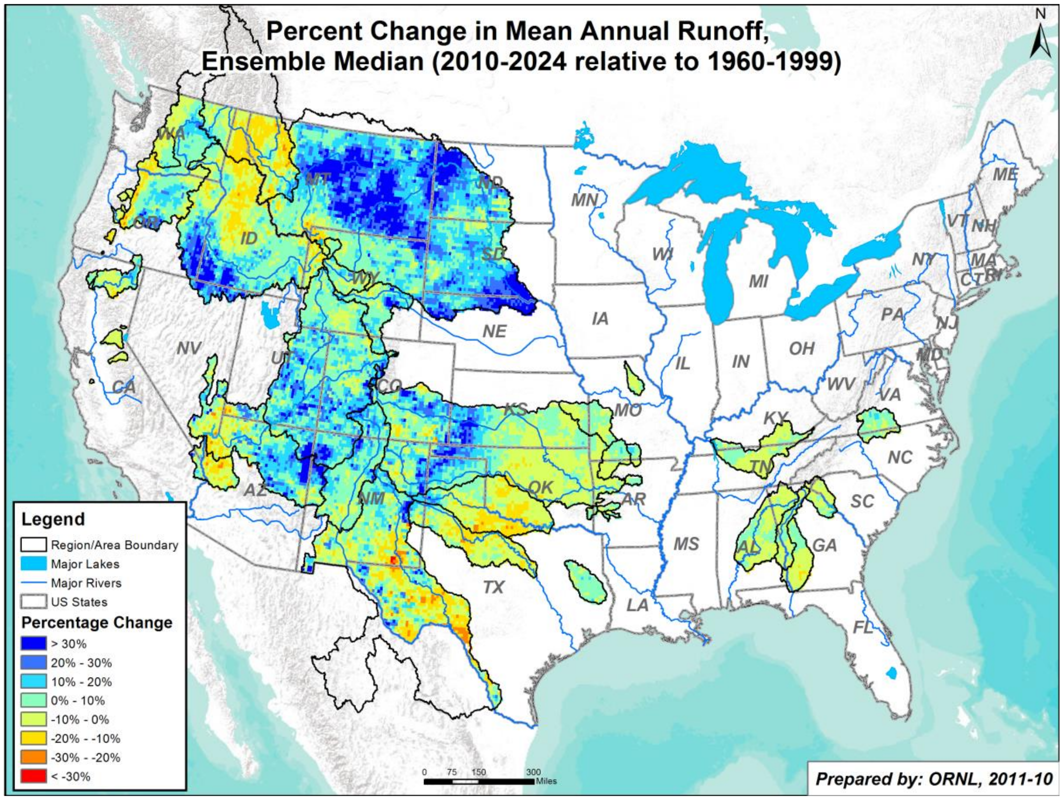
FEDERAL HYDROPOWER SYSTEMS

There are more than 95 gigawatts (GW) of hydropower projects operating in the United States today, including conventional and pumped-storage hydropower. Of this installed capacity, approximately 77 GW are conventional hydropower. In 2009, the hydropower industry (federal and nonfederal) generated more than 270 billion kilowatt-hours (kWh) of electricity, accounting for 65% of total renewable electricity generation. Approximately half of the installed capacity of conventional hydropower in the United States is located at federal facilities. There are significantly more non-federal projects than federal projects, but the average federal project is much larger in size.

The USACE owns and operates 75 hydropower plants with a total rated capacity of 21.5 GW in 16 states, from Washington to Georgia (Figure ES-1). In addition to those federally owned hydropower plants, there are another 90 nonfederal hydropower plants located at USACE dams that have an additional 2.3 GW of capacity. These are not considered in the 9505 Assessment because the power from those projects is not marketed by PMAs. Nonfederal power plants at federal dams are regulated by the Federal Energy Regulatory Commission (FERC).

Reclamation owns and operates 58 federal hydropower plants that generate power for either Bonneville or Western, with a total capacity of 15.1 GW in 11 western states (Figure ES-1). Reclamation's mission is to develop and conserve the nation's water resources in the western United States, and its highest priority is water supply for agriculture. The primary use of the power from Reclamation projects is for delivering water to meet the other authorized purposes of the projects. Power in excess of that used in water delivery is sold to preferred customers through PMAs.

IBWC owns and operates two small hydropower projects on the Rio Grande River with a total installed capacity of 100 MW.



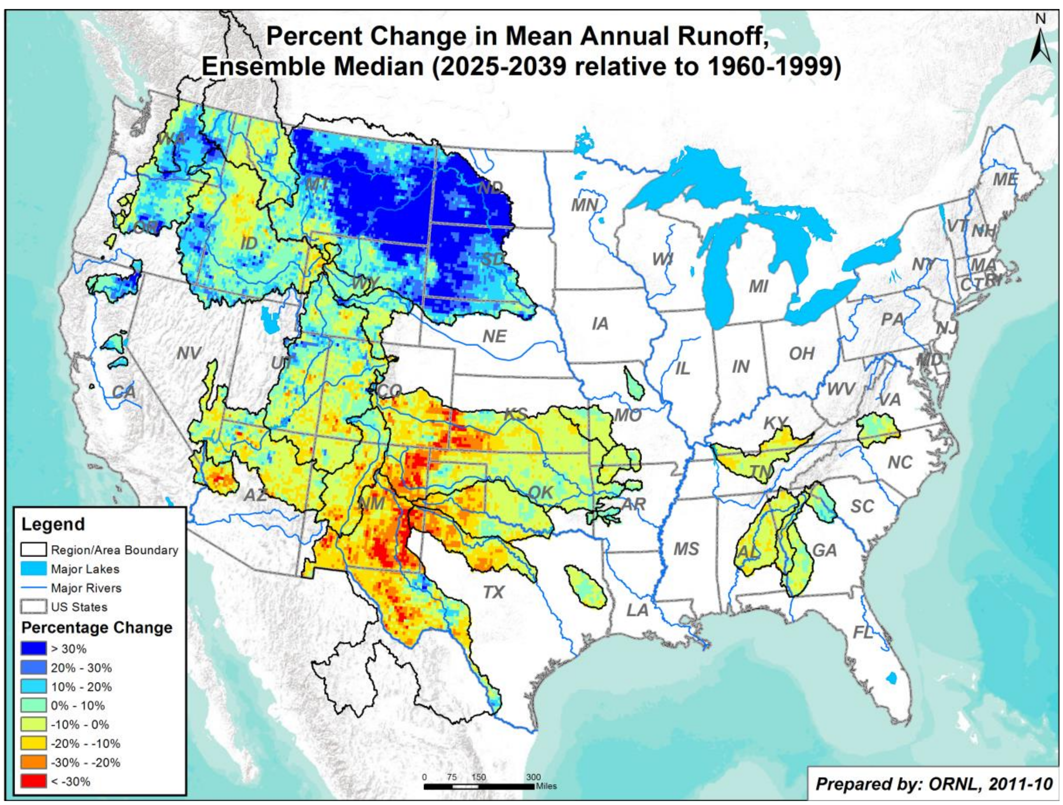


Figure ES-2. Spatial patterns of projected changes in future annual runoff.

Although federal hydropower projects are owned and operated by federal water development agencies, electricity produced at federal hydropower projects is marketed and distributed by the PMAs, which are currently part of DOE. The federal power marketing program began in the early 1900s, when excess hydropower produced at federal projects was sold to repay the government's investment in the projects. PMAs market power from federal projects at the lowest possible rates to consumers that are consistent with sound business principles, so as to encourage the most widespread use of federal assets. If excess power is available beyond the needs of preference customers, the PMAs may sell surpluses to non-preference entities. In practice, the cost-based rates charged by PMAs to their customers are generally lower than the profit-based rates charged by investor-owned utilities.

There are a number of important differences among the PMAs that account for both operational variations and differences in the effects and risks of climate change (Table ES-2). The most important differences are originating legislation and statutory authorities, especially with respect to financing; the relative size of their contribution to meeting regional electricity demand; role in electricity transmission; and number and size of power systems. Each of the four PMAs is a distinct, self-contained entity within DOE, much like a wholly owned subsidiary of a corporation.

Table ES-2. Comparison of federal hydropower among the power marketing regions

Region	Hydropower plants	Installed capacity (GW)	Number of wholesale customers	Average annual generation (billion kWh)	Percent of electricity sales	Average annual revenue (million)
Bonneville	31	20.5	276	77.3	35	$2,306
Western	55	10.2	682	29.7	4	$973
Southwestern	24	2.2	102	5.8	1.4	$164
Southeastern	22	4.1	489	7.8	1.0	$242
TOTAL	**132**	**37.0**	**1,549**	**120.6**	**n/a**	**$3,685**

Bonneville is the largest of the PMAs in terms of total hydroelectric capacity and annual generation, with more than 20 GW of installed capacity managed as the Federal Columbia River Power System (FCRPS), one integrated power system. Federal power sales from the FCRPS account for approximately 35% of the total electricity demand in Bonneville's region. Currently, Bonneville is the only PMA that has the authority to directly finance the operations and maintenance (O&M) costs at federal projects and to develop or acquire new power resources to support customer load growth. Western is the largest PMA in terms of total area (Figure ES-1), but its hydropower projects are dispersed into ten different power systems and federal power sales only account for 5% of total electricity demand. Western has similar financing authority to Bonneville's at some of its Reclamation-authorized hydropower projects but not at all of its projects. Western does not have the authority to acquire new power resources to meet load growth in the future. Southwestern and Southeastern power sales account for approximately 7% and 4% of regional electricity demand, respectively. Efforts are under way to provide direct-financing arrangements for USACE-authorized hydropower facilities in all of Southeastern's and Southwestern's regions and in those parts of Western's region that do not already have it.

WATER AVAILABILITY AND HYDROPOWER

Hydropower generation at federal facilities varies from year to year for a number of reasons, including variations in weather and runoff, changing conditions of hydropower equipment, competing water demands from nonpower uses, and environmental requirements such as fish passage. The data assembled for the 9505 Assessment showed how sensitive federal hydropower projects are to available water, as represented by runoff. With the exceptions of the Rio Grande and lower Apalachicola rivers, the annual generation in assessment areas was highly correlated with observed runoff values (observed data from USGS). In 16 of the 18 assessment areas, runoff explained from 66 to 98% of the variation in annual generation. In four of the areas in Western's region, generation was more related to multi-year runoff than single-year runoff; the reason is the presence of very large surface water reservoirs that carry over water from one year to another. These empirical relationships between generation and runoff were key tools in the 9505 Assessment because they enabled projected changes in future runoff to be translated into projected changes in annual generation.

The observed climate conditions over the past 40 years were described to provide a baseline against which to compare projections of future climate. In many locations, current climate conditions are already changing.

BONNEVILLE REGION

The four major areas of analysis for the Bonneville region are

- BPA-1: the Upper Columbia River upstream and including Grand Coulee Dam
- BPA-2: the Snake River upstream of its confluence with the Columbia
- BPA-3: the lower and mid Columbia River, from Bonneville Dam upstream to the tailwater of Grand Coulee
- BPA-4: the Cascade Mountain projects in southeastern Oregon

All of the federal hydropower projects in the Bonneville region are managed as a single system, the FCRPS. The river drainages providing water to the FCRPS cover large portions of Washington and Oregon, almost all of Idaho, small parts of Montana and Wyoming, and almost 39,000 miles^2 in Canada. The Columbia River basin is the richest region of the United States in terms of water resources and is the most heavily developed region for hydropower. The federal hydropower projects in this region have an average age of 48. This aging infrastructure and the associated rising O&M costs are serious management issues for Bonneville, as well as for the other PMAs.

Much of the water flowing through the Columbia River originates in Canadian watersheds; therefore, the basin is managed as an international resource. The Boundary Waters Treaty was established between the United States and Canada to develop principles and procedures to manage the waters in the basin. Also, an International Joint Commission was created to study and resolve issues relating to joint use of the waters and has since been responsible for coordinating the Columbia River Treaty (CRT). Provisions of the current CRT are subject to change in 2024, which may significantly affect the power benefits of the treaty (100s of millions of dollars per year in terms of flood control, hydropower, and other items). The outcome of the CRT review may change the magnitude and timing of water available for the federal hydropower system on the US side of the border, independent of any effects of climate change.

Bonneville has the third highest precipitation (25.2 in.) and the second highest runoff (12.9 in.) among the PMA regions. Given its lower temperature, evaporation is the lowest among the regions, resulting in the highest runoff-to-precipitation ratio. With the construction of several large reservoirs, Bonneville also has the most abundant hydrologic resources for water supply and hydropower generation. Significant warming has been observed in the Bonneville region over the last century.

In the Bonneville region, annual precipitation was projected to be comparable to the recent historical record in all of the assessment areas, but seasonal patterns were estimated to change. Summer precipitation was projected to decrease, whereas spring and fall precipitation were projected to increase everywhere except in the Cascade area. In the Cascade area, summer precipitation was projected to decrease and only fall precipitation to increase. Winter precipitation is not projected to change significantly in any of the Bonneville areas, indicating that most of the precipitation changes will be changes in timing of rainfall rather than in annual totals: generally drier summers and wetter spring and fall seasons.

Projected changes in runoff in the Bonneville region are different from precipitation patterns because of the influence of the increasing air temperatures on the timing of snowmelt and the amount of evaporation. The strongest change projected for this region was for summer runoff, which was projected to decrease by 20% or more in all areas. Reductions in summer runoff were projected to be greater in the mid-term than in the near-term. The frequency of dry water years was projected to increase from 2 to 3 dry years per decade in all areas. Compared with current conditions, the intensity of low-flow periods could increase (meaning less available water) by as much as 30 to 40% in the summer when they do occur.

The projected changes in runoff in the Bonneville region translate into potential reductions of annual hydropower generation from the FCRPS (Table ES-3). In the near-term period (2010–2024), the median change in annual generation for Bonneville was projected to be –3.9 billion kWh, or a reduction of 4.8% relative to the baseline average simulated from 1960–1999. In the mid-term period (2025–2039), the median change in annual generation for Bonneville was projected to be –44 million kWh, substantially less than in the near-term (Table ES-3). Wet and dry water years will continue to occur, producing a range of changes in annual generation between +4 to –5 billion kWh in the near-term relative to current conditions. The range of annual hydropower generation experienced at the federal projects in Bonneville's region over the past two decades was similar in magnitude to these projections of climate-related change. Nevertheless, a potential annual loss of generation, on the order of 4 billion kWh, is economically significant, especially in a region like Bonneville's that is highly dependent on hydropower.

Table ES-3. Projected near-term (2010–2024) and mid-term change (2025–2039) in average annual generation for each of the PMA regions

	1960–1999 baseline modeled average annual generation (billion kWh)	Projected change in annual generation (billion kWh)					
		Near-term (2010–2024) relative to baseline			Mid-term (2025–2039) relative to baseline		
		median	min	max	median	min	max
Bonneville	80.6	**–3.87**	–5.12	4.14	**–0.04**	–6.46	2.23
Western	29.9	**3.48**	0.55	5.02	**1.14**	–1.16	7.28
Southwestern	5.7	**–0.11**	–0.18	0.60	**0.04**	–1.30	0.17
Southeastern	7.9	**0.04**	–0.82	0.34	**–0.04**	–1.73	0.18

The primary risks to Bonneville operations and contract practices identified by the 9505 Assessment are

- Slight decrease in annual generation in the near-term period (2010–2024) projection and in the summer period in particular
- Increased stress to salmon as a result of rising temperatures and changing streamflow
- Increased risk to Cascade Basin projects' ability to maintain summer water quality and minimum flow objectives
- Expectation that energy demand and use will increase as a result of higher air temperatures
- Long-term increase in streamflow volatility resulting in reduced surplus sales, changes in seasonal pricing and eventual increase in rates for customers.

WESTERN REGION

The six assessment areas of analysis in the Western region are

- WAPA-1: the upper Missouri River and tributaries upstream of the USACE's Gavins Point project
- WAPA-2: area comprising smaller watersheds in the upper parts of the North Platte, South Platte, Bighorn, upper Arkansas, and upper Colorado Rivers
- WAPA-3: the upper Colorado and upper Rio Grande River Basins
- WAPA-4: the lower Colorado River Basin, including Reclamation's Hoover, Davis, and Parker Dams
- WAPA-5: the lower Rio Grande River, including two small projects operated by the IBWC
- WAPA-6: the Central Valley of California (Trinity, Sacramento, American, Stanislaus, and San Joaquin river systems) and Truckee and lower Carson River systems

The Western region covers parts of 11 states from California to the Great Plains and from the Mexican to the Canadian borders. The USACE, Reclamation, and IBWC own and operate hydropower projects in this region. The average age of federal hydropower projects in the Western region is 41 years. The oldest and largest Reclamation hydropower project in this region is Hoover Dam. The 1984 Hoover Power Plant Act granted Western the authority to spend the revenues from Boulder Canyon Project power sales without needing new appropriations. These proceeds are available to Reclamation to pay for O&M expenses and interest costs. Western does not have borrowing authority from the Treasury; however, it does use nonfederal financing to finance Hoover Dam refurbishments and use future power sales as collateral.

In the Western region, annual precipitation was projected to be generally comparable to current conditions except in the upper Missouri and Rio Grande areas. In the upper Missouri River area, annual and summer precipitation were projected to increase. In the Rio Grande area, drier conditions were projected to occur in the summer, fall, and winter seasons. Lower seasonal precipitation was projected throughout the Colorado River in fall and winter, as well as in the lower Colorado in the summer. In the Central Valley of California, precipitation was projected to decrease in the summer and increase in the fall.

Except for the upper Missouri River area, runoff throughout the Western region was projected to decrease to a greater extent than precipitation. In the upper Missouri River, runoff was projected to increase in all seasons. In almost all other Western areas, summer and fall runoff were projected to be lower than current conditions. The Rio Grande River was projected to have lower runoff in all seasons, especially the winter, and changes there were greater in the later time period (Figure ES-2). The northern Central Valley of California was projected to have less runoff in the spring and summer seasons, more runoff in the fall season, but relatively no change in annual or winter runoff.

In the Western region, median annual hydropower generation was projected to increase for both near-term and mid-term periods, based on the 9505 Assessment results (Table ES-3). This trend is due to projected increases in runoff mostly in the upper Missouri River, a finding that is generally consistent with other studies conducted for the SWA. The Western region also had relatively large capacities of reservoir storage, which is operated for water supply and irrigation; these reservoirs can compensate for periods of low water to some degree and mitigate changes in annual hydroelectric generation. However, the projected increase in generation may not be fully realized if the amount of runoff exceeds the current storage capacity of the system, or if changes in flood control operations reduce the volume of multi-purpose reservoir storage capacity. Increasing challenges with flood operations is likely to be a continuing problem in the northern parts of the Western region. In other parts of the Western region, projected total changes in generation were smaller and more variable than in the Missouri River area. The median projected change in annual generation for the whole Western region was 3.5 billion kWh in the near-term and 1.1 billion kWh in the mid-term (Table ES-3).

SOUTHWESTERN REGION

- The four assessment areas of analysis in the Southwestern region are
- SWPA-1: Ozark Plateau rivers in Missouri and northern Arkansas (Osage, upper White, and Salt River Basins)
- SWPA-2: the Arkansas River Basin in Oklahoma and Arkansas, plus the Broken Bow project in the Red River Basin, included for interconnected system reasons
- SWPA-3: the Red and Brazos River Basins in Oklahoma and Texas, plus smaller, upstream parts of the Ouachita River Basin draining the southern side of the Ouachita mountains in Arkansas and Oklahoma
- SWPA-4: the Neches River Basin in southeastern Texas

The Southwestern region covers rivers that run through the Ozark Plateau, southern Great Plains, and Texas coastal plains. This region has less variety in physical and climatological characteristics than the other PMAs. All of the federal hydropower projects in the Southwestern region are multi-purpose projects and are owned and operated by USACE. The average age of these facilities is 47 years and they experience the same aging-infrastructure problems as the other regions. To cover the annual O&M expenses at the facilities, annual appropriations are received from Congress. Growing demand for municipal and industrial water supply is one of the more important water resource issues in the Southwestern region.

Southwestern has the second highest precipitation (29.0 in.), but the third lowest runoff (4.1 in.). The evaporation rate is significant and the runoff-to-precipitation ratio is low (14%). Southwestern provides the least hydropower generation among the four PMAs.

In the Southwestern region, as in others, runoff was projected to change more than precipitation as a result of higher air temperatures that will lead to more evapotranspiration and a lower ratio of runoff to precipitation. All areas of the Southwestern region were projected to experience drier summer seasons. Precipitation in the spring, fall, and winter seasons was projected to be generally similar to current conditions.

The 9505 Assessment projections for future runoff in the Southwestern region indicated the strongest changes in summer runoff. Spring runoff is historically the greatest in the Southwestern region, and projections show the potential for spring runoff to increase, especially in the area of the Arkansas River. However, total annual runoff is relatively unaffected because shifts in seasonal runoff tend to balance each other. The Texas coastal area projections differ from the rest of the region, as total, summer, and fall runoff do not show as much of a decreasing trend as other areas. Projected drying patterns in this region show the frequency of dry water years could increase by one or two events per decade compared with two per decade now, and low-flow periods could be 10 to 30% more intense (i.e., drier) than they have been in the last two decades.

The median 9505 projections for hydropower generation in the Southwestern region indicated a slightly decreasing trend, less than –2%, in the near term and essentially no change in the mid-term period (Table ES-3). However, the range of 9505 projections is large, representing from –31% to +26% change in generation; so there is the potential for year-to-year uncertainty in hydropower operations. Over the most recent 20 years, Southwestern's total annual generation has varied from a high of 9.32 billion kWh in 1993 to a low of 1.54 billion kWh in 2006, representing a range of –75% to +55% of the median generation during that time period. Although it is projected that there will be more frequent dry water years in the future in this region, the range of near-term and mid-term changes in generation should be similar to what Southwestern has encountered in recent years, at least through 2039.

The potential water and power issues identified in the 9505 Assessment will continue to be reviewed and monitored in conjunction with other water resources trends in Southwestern's region to ensure that power contract obligations are met.

SOUTHEASTERN REGION

The four major areas of analysis for the Southeastern region are

- SEPA-1: the Roanoke River Basin in Virginia and North Carolina
- SEPA-2: the Cumberland River Basin in Kentucky and Tennessee
- SEPA-3: the combination of the Savannah, upper Apalachicola, and Alabama River Basins in South Carolina, Georgia, and Alabama
- SEPA-4: the lower Apalachicola and Flint River Basins in Georgia and Florida

This region is distinctly different from the other three PMA regions because of its lower elevations, higher precipitation, and more heavily vegetated land cover. All of the federal hydropower projects in the Southeastern region are owned and operated by USACE. The oldest projects are the Allatoona (SEPA-3) and Center Hill (SEPA-2), coming on line in 1950; and the newest project is Richard B. Russell, coming on line in 1984. The average age of these facilities is 35 years and they experience the same aging-infrastructure problems as the other regions. Southeastern and the USACE receive annual appropriations from Congress to finance their operations and construction of hydroelectric projects.

The Southeastern region has the same competing water use challenges as the other regions—growing demands for municipal and industrial water supply, flood control, navigation, aquatic ecosystems, and hydropower generation.

The Southeastern region is first in precipitation (52 in.) and first in runoff (19.8 inc.) among PMA regions. It is also the hottest, with strong evaporation. The runoff-to-precipitation ratio is the second highest (38.0%). Fewer regional climate projection studies have been conducted for this region. However, some analyses show that the annual temperature of the region did not have a significant change until 1970, when there was a 1.8°F increase, with the largest increase over the winter months. Precipitation has increased significantly over most of the region, but summer and winter precipitation decreased significantly over the eastern part of the region. No region-wide significant trends in runoff have been observed.

The projected climate change patterns in the Southeastern region were different from those for the more western PMA regions, as might be expected. Increases in air temperature in the Southeastern region were projected to be in the same 2–4° range as in the other regions except that the winter season was not expected to be significantly different from current conditions. Precipitation changes were also expected to differ less from current conditions, with a few important exceptions. Summer and fall precipitation were projected to increase in the Roanoke River Basin in Virginia, while winter precipitation was projected to decrease. Annual and summer precipitation were projected to decrease in the Cumberland River Basin of Kentucky and Tennessee, and annual precipitation was projected to decrease in the lower Apalachicola River Basin of southern Georgia.

Changes in runoff in the Southeastern region were projected to be somewhat more intense than the changes in precipitation, similar to the Southwestern region. The Roanoke River Basin could experience significantly higher runoff in the summer and fall seasons. The Cumberland River Basin could have significantly lower runoff in all seasons except in summer. Total annual runoff in the Alabama and Savannah River systems was not projected to change much, but runoff in the spring and winter seasons could be lower and summer runoff could be higher. In the lower Apalachicola River Basin, both annual and winter runoff were projected to decrease. There are predicted to be one or two more dry years per decade throughout the Southeastern region compared with current conditions; and when low-flow periods do occur, they may be 10 to 30% more intense than now.

The median projected change in annual federal hydropower generation for the Southeastern region is relatively small: a 0.5% increase in the near-term period and a 0.5% decrease in the mid-term period (Table ES-3). However, as in other regions, the range between high and low ensemble members is high, indicating the likelihood of extreme water years and generation outputs. In the past 20 years, total annual generation from projects in this region has ranged between a maximum of 9.44 billion kWh in 1993 to a minimum of 4.29 billion kWh in 2008. Although the projected change in generation may add to this historic variability, and more dry water years are projected for the future, the range of annual generation in the Southeastern region is projected to be similar to the recent past.

CONCLUSIONS

The 9505 Assessment described in this report is the first comprehensive assessment of climate change impacts that specifically focuses on the entire federal hydropower portfolio in the United States. The methods were designed to provide an objective, quantitative evaluation of the effects and risks to federal hydropower that could be applied consistently across all four of the PMA regions. The task of developing a quantitative assessment approach that could evaluate climate impacts consistently across all federal hydropower projects, in a short period of time, was a major technical challenge. The modeling approach developed for the 9505 Assessment was successful with respect to evaluating changes in annual runoff and hydropower generation. A new integrated database was assembled to describe hydrology and hydropower at a regional scale for all four PMA regions, and those data were used to develop regression models of average annual generation as a function of runoff. Future climate was simulated with a series of global and regional models, and model output was adjusted to be consistent with observed data for the recent past. This modeling framework enabled current climate conditions to be projected 30 years into the future to estimate how changes in water availability would affect hydropower generation at federal projects. The 9505 Assessment results therefore are responsive to the Congressional direction in SWA.

Climate variability and change are not the only factors that are affecting water availability for federal hydropower. Other important factors currently influencing federal hydropower are reallocation of water storage to nonpower uses and the aging of federal hydropower assets, which is leading to lower reliability and more outages. Future 9505 Assessments should address the interactions among climate and nonclimate influences on water resources, including intra annual variability. While the projected changes in generation are similar to the recently observed variability of generation from federal hydropower and may appear to be manageable within the time periods examined, the extremes in water years, both wet and dry, will pose significantly greater challenges to water managers in the later parts of the 21st century.

Section 9505 of SWA instructed DOE to submit a first Report to Congress on climate effects on federal hydropower, then to repeat these assessments every 5 years through 2023. There are a number of ways that the assessment approach presented here can be improved for subsequent assessments:

- Establish an integrated monitoring, data collection, storage and analysis project for hydropower plant operations and generation, with at least monthly resolution at all federal facilities.
- Develop a more detailed modeling approach to link project operations and climate variables to generation patterns and water resource management decisions at federal hydropower projects.

- Integrate climate change assessment with other water resources planning activities so that the full spectrum of factors affecting water availability can be considered together.
- Establish a regular interaction of hydropower interests in the community of scientists working to improve models of future climates, so that the key variables affecting hydropower are incorporated into climate models.

1. INTRODUCTION

1.1 LEGISLATIVE BACKGROUND

The SECURE Water Act (SWA) of 2009 was signed into law on March 30, 2009, as part of the Omnibus Public Lands Management Act (Public Law 111-11). SWA authorizes federal agencies to study and improve water management and to increase the acquisition and analysis of data describing water resources for irrigation, hydropower, municipal uses, environmental conservation, and other purposes. A primary purpose of SWA was to provide authority for analysis and planning for potential effects that climate may have on the hydrologic cycle that provides water for communities, economic growth, and protection of ecosystems in the western states and other parts of the United States. There are ten sections of the SWA legislation:

- Section 9501. Findings
- Section 9502. Definitions
- Section 9503. Reclamation Climate Change and Water Program
- Section 9504. Water Management Improvement
- Section 9505. Hydroelectric Power Assessment (this report)
- Section 9506. Climate Change and Water Intragovernmental Panel
- Section 9507. Water Data Management by the US Geological Survey
- Section 9508. National Water Availability and Use Assessment Program
- Section 9509. Research Agreement Authority
- Section 9510. Effect

Section 9505(c) of SWA directs the Secretary of Energy to assess the effects of global climate change on water supplies required for hydropower generation at federal water projects and to present the results in a Report to Congress (see Appendix A for the text of the original legislation). The Department of Energy (DOE) is also authorized to repeat these assessments every 5 years until 2023. The 9505 Assessment has been conducted in coordination with the administrators of each of the Federal Power Marketing Administrations (PMAs) that sell and distribute hydroelectricity from federal projects, as well as with the US Army Corps of Engineers (USACE) and the Bureau of Reclamation (Reclamation) who own and operate federal dams.

Sections 9503 and 9505 both deal with climate change effects on the hydrologic cycle and water resource issues. The 9505 Assessment described in this report differs from other SWA products in that 9505 focuses specifically on federal hydropower and power marketing at a national level. Section 9503 addresses a broader range of water resource issues and water users, but just in eight western river basins. Reclamation completed its 9503 report and sent it to Congress in April 2011 (Reclamation, 2011c). Recognizing the overlap between 9503 and 9505, DOE and Oak Ridge National Laboratory (ORNL) staff worked with Reclamation to ensure the use of comparable methods. Although the 9505 Assessment methods (see Section 2) vary somewhat from the 9503 assessment methods, because of the differences in scope and the need to apply a consistent assessment approach across a wider range of regions, the conclusions of the two reports are generally consistent and complement each other well.

1.2 THE FEDERAL HYDROPOWER SYSTEM

Hydropower is the foundation of renewable energy in the United States, based on both its long history of development and on the diverse benefits it provides to electric power systems. Approximately half of the national hydropower portfolio is located at federal facilities. Hydropower provides substantial energy and nonenergy benefits, such as recreation opportunities and environmental enhancements, that affect all 50 states either directly or indirectly through the transmission grid. In 2007, the hydropower industry, including federal and nonfederal projects, accounted for 71% of total renewable energy generation (Gruenspecht, 2008), and generated 248 billion kilowatt-hours (kWh) of electricity. Although non-hydropower renewables are expanding rapidly in the United States, as of 2007, the total generation from hydropower was still more than three times the total from all other types of nonhydro renewable energy combined.

In total, there are more than 95,000 megawatts (MW) of hydropower projects operating in the United States today, including conventional and pumped-storage hydropower. Of this installed capacity, 77,400 MW is conventional hydropower, which is split approximately evenly between federal and non-federal projects (Table 1-1). Conventional hydropower refers to traditional project designs that use a combination of hydrostatic head and flow through turbines to generate electricity. This is distinguished from the newer, hydrokinetic turbines that use only the kinetic energy in water velocity and not head. There are significantly more nonfederal projects than federal projects, but federal projects tend to be larger in size on average (Table 1-1).

Table 1-1. Numbers and sizes of existing federal and non-federal hydropower projects in the United States Nonfederal projects are those subject to regulation by FERC

	Number of projects	Total capacity (MW)	Average project size (MW)
Corps of Engineers	75[a]	21,500	287
Bureau of Reclamation	58[b,c]	15,100	260
Tennessee Valley Authority	30[c]	5,200	173
International Boundary and Water Commission	2	100	50
Total federal	***165***	***41,900***	***254***
FERC licenses	1,012	53,500	53
FERC exemptions	595	800	1.4
Total nonfederal	***1,607***	***54,300***	***34***

[a] This includes two projects that are not marketed through PMAs.
[b] Reclamation owns 82 power plants, but energy from only 58 of those is marketed through federal PMAs
[c] TVA and Lewiston Powerplant are not included in the 9505 assessment.

Nonfederal hydropower is regulated by the Federal Energy Regulatory Commission (FERC) under authority defined in the Federal Power Act. Ownership of nonfederal projects varies widely, including large, public utilities (e.g., Pacific Gas and Electric Company or the New York Power Authority), municipal and irrigation districts, smaller rural electric cooperatives, and independent power producers. FERC regulates nonfederal hydropower development through a well-developed process of licensing.

The first hydropower projects in the United States were built by nonfederal entities in the late 1800s near irrigation districts in the West and small industrial mills in the East. The most active period of development was between 1950 and 1975. Although federal dam construction essentially stopped in the 1980s, nonfederal development continued between 1975 and 2000, but at a slower rate. The total installed capacity of conventional hydropower peaked between 1997 and 2002 at about 79,000 MW (EIA, 2007). It has been decreasing since 2002, largely because of dam removal initiatives across the nation. However, this trend may begin reversing as new incentives for renewable energy come into play.

1.2.1 Federal Hydropower Agencies

Federal hydropower consists of projects built and/or operated by one of four agencies: USACE, Reclamation, the Tennessee Valley Authority (TVA), and the International Boundary and Water Commission (IBWC). The USACE has the most projects, followed by Reclamation, TVA, and then IBWC. IBWC owns and operates two small hydropower projects on the Rio Grande River; the hydropower from those plants is marketed by Western. Energy production from hydropower is only one of the many authorized purposes of federal dams. Other project purposes with which hydropower must co-exist include flood control; navigation; water supply for municipalities, industries, and agriculture; recreation; and protection of environmental resources such as water quality, fish, and wildlife. Given that other nonpower purposes may have a higher priority than power at specific projects, hydropower can be more or less a byproduct of water management operations at federal projects, being generated when excess water is available.

The USACE currently operates 75 hydropower plants with a total rated capacity of 21,500 MW in 16 states, from Washington to Georgia (Figure 1-1). In addition to those federally owned hydropower plants, there are another 90 nonfederal hydropower plants located at USACE dams with an additional 2,300 MW of capacity (USACE, 2009). Nonfederal power plants at federal dams are regulated by FERC. The oldest USACE hydropower facility is at Bonneville Dam on the lower Columbia River, which came on line in 1938. The most recent USACE project to come on line was the R.D. Willis project in Texas in 1989.

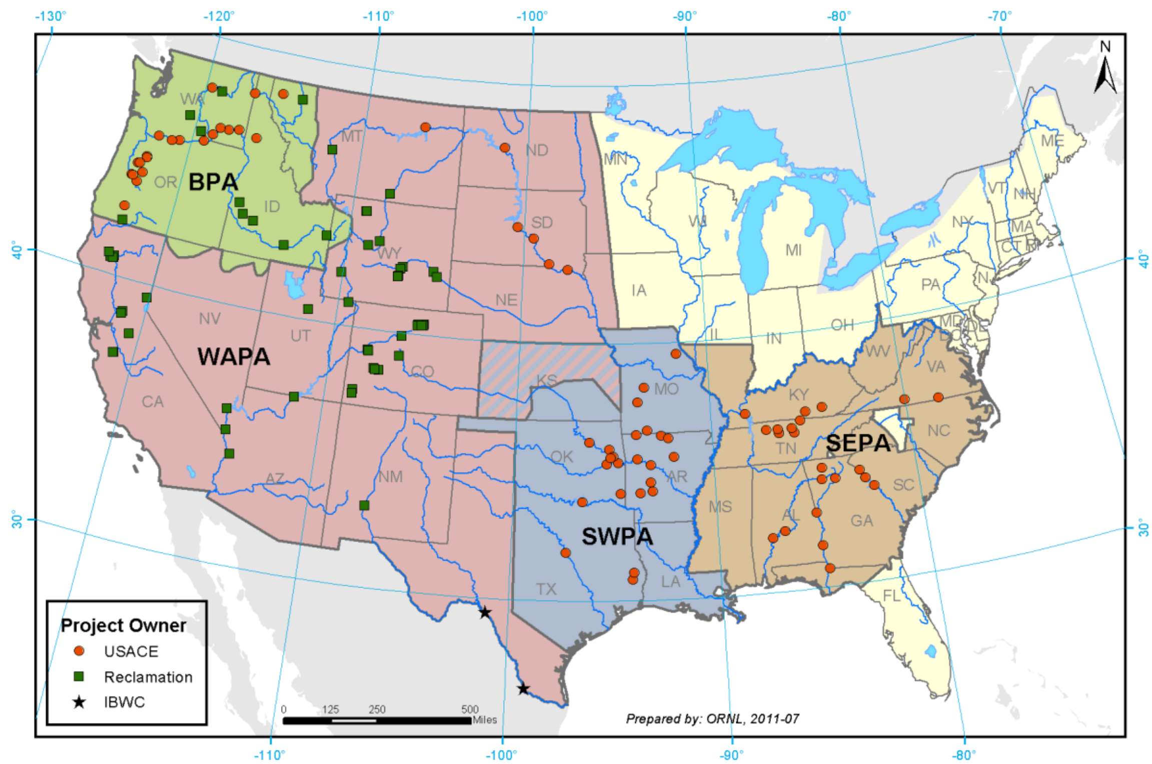


Figure 1-1. Map of federal hydropower facilities built and operated by the US Army Corps of Engineers and the Bureau of Reclamation, plus federal power marketing regions in the United States. Note that part of Kansas is supplied by both Western and Southwestern.

Reclamation owns and operates 58 federal hydropower plants with a total capacity of 15,100 MW in 11 western states. The mission of Reclamation is to manage, develop, and protect water and related resources in an environmentally and economically sound manner in the interest of the American public. A large part of its mission is the delivery of water for irrigation to end-users in the western states. Electricity produced at Reclamation facilities is either used internally at projects or sold as surplus power. The primary use of the power is to deliver water to meet the other authorized purposes of the projects. The oldest Reclamation hydropower plant is the Theodore Roosevelt facility on the Salt River in Arizona, which began operation in 1909. The largest is Grand Coulee Dam, which has an installed capacity in excess of 6,900 MW, making it among the 10 largest hydropower plants in the world.

Although federal hydropower projects are owned and operated by federal water development agencies (USACE, Reclamation, or TVA), electricity produced at USACE and Reclamation projects is marketed and distributed by the PMAs, which are part of DOE (Lane, 2007). TVA owns, operates, and markets power from its projects, which are all located in the Tennessee River Basin. PMAs market power from federal projects at the lowest possible rates to consumers consistent with sound business principles, so as to encourage the most widespread use of federal assets. There are four PMAs: Bonneville Power Administration (BPA or Bonneville), Southeastern Power Administration (SEPA or Southeastern), Southwestern Power Administration (SWPA or Southwestern), and Western Area Power Administration (WAPA or Western). Bonneville is the largest of the PMAs in terms of marketed hydroelectric capacity and annual generation (Figure 1-2). However, Western is the largest PMA in terms of total area served (Figure 1-1). Each of the four PMAs is a distinct, self-contained entity within DOE, much like a wholly owned subsidiary of a corporation. The power marketing program within DOE began in the early 1900s, when excess hydropower produced at federal projects was sold to repay the government's investment in the projects. Currently, Bonneville is the only PMA that has the authority to directly finance the operations and maintenance (O&M) costs at USACE projects. Western has similar financing authority for Reclamation-authorized hydropower projects. Efforts are under way to enable Southeastern, Southwestern, and Western to have a similar direct-financing arrangement for USACE-authorized hydropower facilities in all of their regions.

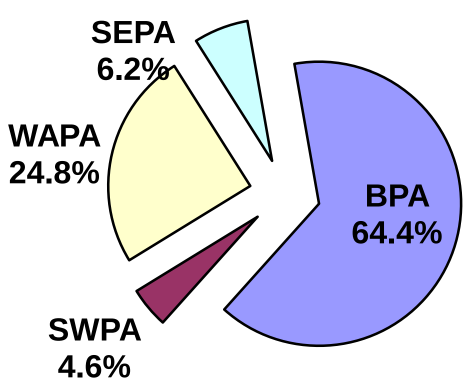


Figure 1-2. Average annual generation from federal hydropower projects distributed among the four PMAs. The total PMA generation is 120 billion kWh per year for the period from 1971 to 2008.

The scope of this report is limited to federal hydropower projects that are operated by the USACE and Reclamation. TVA is not a PMA, and electricity from TVA hydropower projects is not marketed by a PMA, so its projects were not included in the climate change assessment presented here.

1.2.2 Marketing Federal Hydropower

The PMAs are federal agencies whose mission is marketing power produced at federal multipurpose dams. By law, PMAs are to give preference in the sale of federal power to public bodies, such as electric cooperatives and municipalities. Such entities are generally called "preference customers." The Reclamation Project Act of 1939 states that "preference shall be given to municipalities and other public corporations or agencies; and also to cooperatives and other non-profit organizations financed in whole or in part by loans made pursuant to the Rural Electrification Act of 1936 and any amendments thereof." If excess power is available beyond the needs of preference customers, the PMAs may sell surpluses to non-preference entities. According to the Flood Control Act of 1944, PMAs are to provide electricity "at the lowest possible rates consistent with sound business principles" (Lane, 2007). In practice, the cost-based rates charged by PMAs to their customers are generally lower than the profit-based rates charged by investor-owned utilities (IOUs; EIA, 1999).

Three of the PMAs receive some appropriations from Congress and use these appropriations in various ways to fulfill each of their missions, whereas BPA is self-financed through rate recovery. The PMAs adhere to DOE Order RA 6120.2 which established the basic parameters for financial reporting, procedures, and methodology policy for power investment repayment. This order sets forth guidance for interest rates on investment, power repayment periods, and order of repayment among other things (DOE, 1979). DOE Order RA 6120.2 also requires PMAs to perform annual power repayment studies (revenue requirement studies, in the case of Bonneville). Those studies estimate the amount of federal investment left to be amortized, as well as revenues and expenses over the remainder of the repayment period. Rate cases are public processes the results of which must be approved by the Deputy Energy Secretary and FERC. Unlike rates, which can be changed as required when power repayment studies warn about insufficient revenues, capacity and energy allocations are determined in the contracts signed with customers.[1] Commitments for firm power (energy plus capacity) in current contracts remain firm for the life of the contract.

A report by the General Accounting Office (GAO, 2000) identified key differences in the rate setting practices of PMAs versus IOUs. First, PMAs have the ability to defer repayment of appropriated debt until the year in which it is due (rather than facing mandatory annual repayments as most loans do), as they operate under a balloon payment methodology. Second, PMAs do not have shareholders for whom to generate a return and, generally, do not pay taxes.[2] Third, IOUs' financing consists of both equity and debt, whereas the PMAs rely mostly on debt. Fourth, IOUs receive most of their revenue from retail sales whereas PMAs sell almost entirely at the wholesale level. GAO (2000) observed that while IOUs are increasingly operating under market-based rates, PMAs continue having, by law, cost-based rates.

1.3 ORGANIZATION OF THE REPORT

In addition to the introduction and conclusion sections, this report is organized into five principal sections, first describing the assessment methods used and then the assessment results for each of the four PMAs. The conclusion section contains a comparison of results across the PMA regions, a summary of the major findings, and ideas for improving the subsequent 9505 Assessments that are called for in SWA.

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[1] Capacity is the instantaneous amount of power available to meet consumer demand. It is measured in kilowatts or megawatts. Energy is the amount of electricity delivered over time and is measured in kilowatt-hours. PMAs market capacity and energy separately.

[2] On the other hand, Bonneville and the Western area face some extra obligations that IOUs do not have. Congress has assigned them to collect additional revenue to repay the federal appropriations that financed certain irrigation facilities.

The assessment methods, data sources, and analyses used in this report are described in Section 2. A combination of observational data, model-based data, and literature reviews are used in the 9505 Assessment. As called for in SWA Section 9505 legislation, the climate assessment is based on the best available scientific information, in consultation with the US Geological Survey (USGS) and the National Oceanographic and Atmospheric Administration (NOAA). The 9505 Assessment methods were chosen to enable a consistent application across all four of the PMA regions and all federal hydropower projects. In addition to the quantitative analyses done specifically for this report, a discussion of other, similar studies of climate change impacts is provided.

Sections 3, 4, 5, and 6 of this report contain PMA-specific results for Bonneville, Western, Southwestern, and Southeastern, respectively. In each of these sections, there are descriptions of the federal hydropower projects in the region, relevant power marketing activities, existing climate and hydrology, generation patterns, impacts of potential climate variability and change, and mechanisms/procedures used to deal with the variability of water supply. Power marketing issues covered include long-term power contracts, contingent capacity contracts, and short-term power sales. More detailed technical information is presented in appendices to this report and is cross-referenced where it applies.

The final section of the report, Section 7, presents a summary and conclusions of the 9505 Assessment, beginning with a comparison among the regions. The major findings are divided into discussions of the assessment methods and data, the direct effects of climate change on federal hydropower, the current capabilities to manage risks associated with climate change, and interactions between climate change effects and other stressors on federal hydropower. The report ends with recommendations on actions that may be taken to prepare for future assessments under SWA Section 9505.

The accuracy and applicability of the 9505 Assessment benefited greatly from extensive consultation with other federal agencies, as directed by Congress in SWA, and from a thorough technical review that was consistent with the Office of Management and Budget's policies on information quality. The DOE team conducting the 9505 Assessment worked closely with technical staff from the PMAs, Reclamation, and USACE to ensure consistency of methods and data. A review draft of the 9505 Assessment was prepared in July 2011 and subjected to a comprehensive peer review; the results of that review are summarized in Appendix J.

The Report to Congress that is called for in SWA Section 9505 will be produced separately from this 9505 Assessment report but will be based on the details and conclusions presented here. Although they are not explicitly presented in this 9505 Assessment report, the Administrator Recommendations from each of the PMAs will be included in the subsequent Report to Congress.

2. THE 9505 ASSESSMENT APPROACH

The assessment approach developed for this report is designed to provide a consistent, quantitative analysis of potential climate change effects across all four of the PMA regions, enabling inter-regional comparisons at a national level. Although in the past some regions have been studied in more detail, different analytical techniques were used; and there was no consistent approach that would allow policy makers to examine possible impacts of potential climate change effects across the entire portfolio of federal hydropower resources. To support policy analysis at the national level, this study uses a consistent set of analytical methods and data resources for all regions.

2.1 DATA ACQUISITION AND ANALYSIS

The 9505 Assessment required the integration of a relatively large number of different types of data that had not been previously used together (Table 2-1). These included hydropower project characteristics, generation records, observed hydrology and meteorology data, watershed and land surface data, and model data from a series of different simulation models. All supporting datasets for the 9505 Assessment on federal hydropower are summarized in this section.

Table 2-1. Data sources used in the 9505 Assessment

Subject	Data source	Reference
Hydropower project characteristics	National Hydropower Asset Assessment Program, ORNL Form 860 Database, EIA National Inventory of Dams, USACE Hydropower Asset Management Partnership, Reclamation/Hydro-Québec/ USACE/Bonneville	Hadjerioua et al., 2011
Hydropower generation	From 906, 920, and 923 database, EIA Bureau of Reclamation USACE DOE Power Marketing Administrations	
Observed runoff and streamflow	WaterWatch Program, USGS HYDAT database, Environment Canada	Brakebill et al., 2011
Observed temperature and precipitation	PRISM Climate Group, Oregon State University University of Delaware Air Temperature and Precipitation	Daly et al., 2002; Willmott and Matsuura, 1995
Watershed boundary	Watershed Boundary Dataset, NRCS National Hydrography Dataset, USGS/EPA	USGS and USDA-NRCS (2009)
Topography	Global 30 arc second elevation data (GTOPO30), USGS	
Land cover	Moderate Resolution Imaging Spectroradiometer (MODIS), NASA	
General circulation model (GCM)	Community Climate System Model version 3 (CCSM3)	Collins et al., 2006
Regional climate model (RCM)	Abdues Salam Institute for Theoretical Physics Regional Climate Model version 3 (RegCM3)	Pal et al., 2007
Hydrologic model	Variability Infiltration Capacity model	Maurer et al., 2002

ORNL = Oak Ridge National Laboratory; USACE = US Army Corps of Engineers; EIA = Energy Information Administration; USGS = US Geological Survey; NRCS = National Resources Conservation Service; USDA = US Department of Agriculture; NASA = National Aeronautics and Space Administration

The US federal hydropower infrastructure dataset was organized by the National Hydropower Asset Assessment Program (NHAAP, Hadjerioua et al., 2011). NHAAP is a multi-agency effort, led by ORNL for the Wind and Water Power Program of DOE. Hydropower-related data were incorporated from EIA, FERC, USACE, Reclamation, USGS, and TVA, including data on power generation, plant capacity, turbine types, equipment ages, dam characteristics, historical streamflow records, stream segments, and meteorological observations. The baseline historical US hydropower generation data were collected and organized from the DOE EIA Form 906/920/923 Monthly Power Generation Database (EIA, 2010) from 1970 through 2008. When available, records obtained directly from Reclamation, the USACE, and PMAs are used to update parts of the plant generation data. The corresponding power marketing data are also gathered from the PMAs.

To quantify the amount of historic and modeled water availability for a hydropower plant, the geographical boundary of the corresponding watershed is needed. The watershed boundaries can be used to isolate and compute the spatially averaged precipitation and runoff from existing gridded datasets. In this assessment, all upstream regions above federal hydropower plants are considered. Based on the geographical coordinates of federal hydropower plants, the corresponding watersheds are assembled by the 12-digit hydrologic units of the Watershed Boundary Dataset (NRCS, 2011). The hydrologic units are a standard watershed labeling system in the United States. Hydrologic units are determined by natural topography, in which the streamflow within each unit should have a common outflow water body (ocean, lake, or confluence to other river systems). Hydrologic units are hierarchically labeled by hydrologic units codes (HUCs). By expanding the HUC from 2-digit (region), 4-digit (subregion), 6-digit (basin), 8-digit (subbasin), 10-digit (watershed), to 12-digit (subwatershed), watersheds with different levels of details are defined.

The topographic information used to describe the areas of analysis comes from the GTOPO30 global digital elevation model that has a horizontal resolution of approximately 1 km (USGS, 2009). The GTOPO30 dataset, developed by USGS staff in 1996, is available through multiple web sites, including the Distributed Active Archive Center (DAAC) for Biogeochemical Dynamics at ORNL.

Land cover characterization for the areas of analysis is based on remote sensing data from the Moderate Resolution Imaging Spectroradiometer (MODIS) on NASA’s Terra satellite (Friedl et al., 2002). The MODIS product used here is a 500-m resolution classification scheme from the International Geosphere-Biosphere Programme (IGBP) that distinguishes 16 vegetation cover types, including water, snow, and ice. These data are available from the ORNL DAAC site (IGBP, 2007).

The USGS WaterWatch Computed Runoff (Brakebill et al., 2011; USGS, 2010) was used to study the historic hydrology for each of the PMA watersheds. Unlike gauge observation that reports streamflow discharge at a specific river location, runoff represents the streamflow availability for a region. Following the definition given by USGS WaterWatch, runoff can be estimated by dividing the observed streamflow discharge by its corresponding drainage area, and it has a similar unit to precipitation (depth/time). Therefore, runoff can be compared with precipitation to understand how much effective rainfall has eventually become streamflow. In computing runoff for a watershed of interest, all stream gauges that are located within its drainage basin are examined and the proper weighting factors are determined to compute a combined runoff. Given the abundant streamflow observations in the United States, runoff can now be reasonably computed in the form of time series. The USGS Computed Runoff is available in terms of monthly time series from 1901 until the present for each 8-digit hydrologic unit (subbasin).

The existing air temperature and precipitation characteristics in each PMA region were defined by data from the PRISM Climate Group at Oregon State University (Daly et al., 2002). The PRISM acronym stands for Parameter-elevation Regressions on Independent Slopes Model, indicating that data values are calculated with a weighted climate-elevation regression to compute the areal average of meteorological observation from gauge networks. The monthly PRISM output is grid-based and available at 4 by 4 km spatial resolution from 1895 to the present for the entire conterminous United States

Since USGS runoff and PRISM meteorological data were unavailable for parts of the watersheds in the assessment areas outside the United States (both in Canada and Mexico), the University of Delaware Air Temperature and Precipitation dataset (Willmott and Matsuura, 1995) are used to populate the missing observations. Although the Delaware dataset is in a rougher 0.5° spatial resolution, it provides estimates for the assessment areas outside of the United States. As for runoff, monthly streamflow observations from 62 gauge stations with natural flow conditions from the HYDAT Database (Environment Canada, 2011) were used to derive runoff in Canada. An approach similar to USGS WaterWatch Runoff, using drainage areas as weighting factors, was used to estimate monthly regional runoff in the Canadian portion of the Columbia River Basin. All related watersheds in Canada were treated as a whole with no further breakdown. Given that there is much less streamflow observation available on the Mexico side, no action was performed to estimate the Rio Grande runoff in Mexico. This simplification should have limited influence on the entire assessment, since the hydropower plants in the Rio Grande watersheds are among the smallest in this assessment.

Given that there are no existing database and framework for climate change impact assessment of hydropower generation at the national and regional scales, the first 9505 Assessment focuses on developing the larger-scale projection instead of a plant-wise assessment. The established database and framework through the first assessment will allow more in-depth analysis in the future 9505 reports at each individual plant (and watershed). Therefore, four assessment areas are determined for Bonneville, Southwestern, and Southeastern, and six assessment areas are determined for Western. The hydropower infrastructure and generation data within each of the assessment areas are aggregated for analysis. Similarly, the corresponding runoff, precipitation, and temperature are computed from USGS WaterWatch Runoff and PRISM for each assessment area. The process of computing regional temperature, precipitation, and runoff are illustrated in Figure 2-1. Assuming that an assessment area intersects with nine cells with observation Q_1–Q_9, the overlaid areas A_1–A_9 can be computed from standard geographic information system software. The areas A_1–A_9 can then be treated as weighting factors to compute a weighted average from Q_1–Q_9. Therefore, the regional values can be determined even if the cells are irregular in shape (e.g., 8-digit HUCs). This approach can also account for unequal grid sizes along various latitudes and hence will be used for merging climate projection data that will be described in the next section.

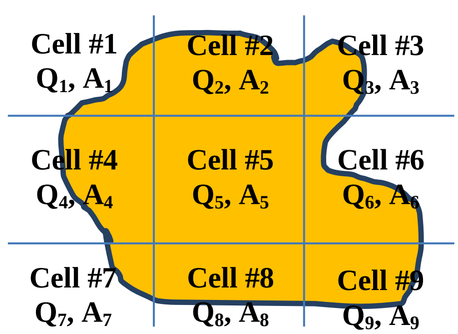

Figure 2-1. Illustration of regional data merging.

To help understand the relationship between observed variables, the 1971–2008 average annual, spring (March, April, and May), summer (June, July, and August), fall (September, October, November), and winter (December, January, and February) temperature, precipitation, runoff, and generation are summarized for each of the PMA assessment areas (shown in the PMA sections). In addition, the cumulative distributions of observed monthly temperature, rainfall, runoff, and generation are illustrated in Appendix D to support detailed examination. On the graphs in Appendix D, solid black lines represent the distribution curves across the entire year, dashed green lines represent the spring months, dashed red lines the summer months, dashed black lines the fall months, and dotted blue lines the winter months.

By examining correlations between the four observed variables, it was found that both precipitation and runoff significantly influence generation. Therefore, linear regression analysis is performed for precipitation-generation and runoff-generation for each of the PMA assessment areas (shown in the PMA sections). Since the power generating facilities and operation schemes changed with time, the regression is performed only on the latest 20 years of data (i.e., water years 1989 to 2008). Overall, the correlation between runoff and generation is consistently strong, except in several Western assessment areas with larger reservoirs where multi-year storage plays an important role (e.g., Hoover Dam). Replacing the annual runoff with the 2-year, 3-year, to 6-year running averages significantly improves the correlation between runoff and generation. For each PMA assessment area, the most appropriate regression formula is hence derived and used to assess the potential climate impacts on annual hydropower generation.

2.2 CLIMATE PROJECTIONS

A series of global and regional simulation models are used to project current climate into the future (Figure 2-2). The future climate modeling results are referred to as "projections" rather than forecasts in this report, because currently available models do not make absolute predictions of date-specific climate conditions.

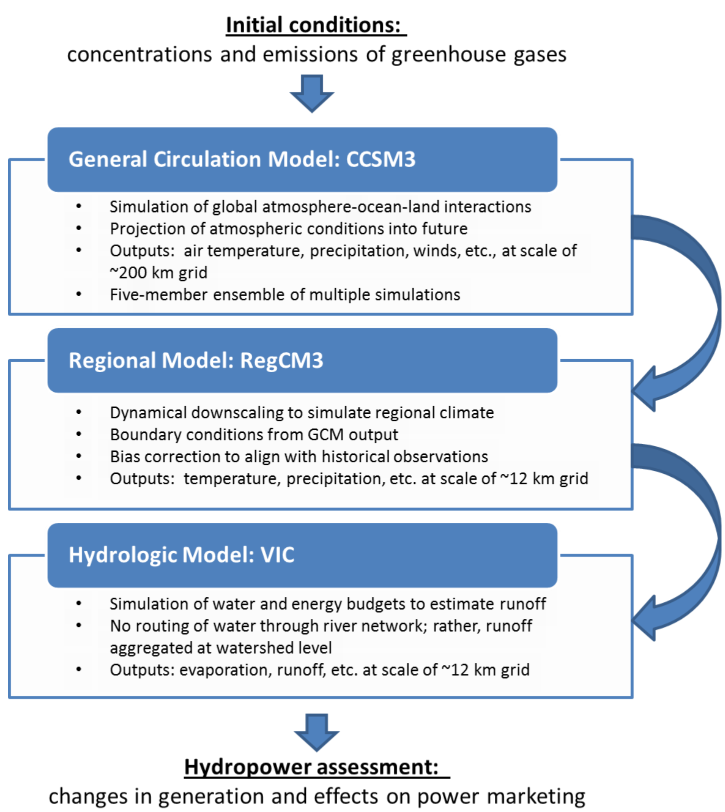

Figure 2-2. Series of models applied in the 9505 Assessment. See text for definition of model names.

To assess future hydrologic conditions that affect hydroelectric power generation, assumptions must be made about the future climate. These climate assumptions will then be used to evaluate the statistical relationships developed in the previous section. To make projections of future climate, two major approaches are typically used, including statistical extrapolation and model-based simulation. Based on a comprehensive set of observations (e.g., in-situ observations such as temperature and precipitation, and paleoclimatology evidence such as tree ring chronology) with sufficiently long periods of records, statistical extrapolation depicts the future climatology from identified historic patterns. Advanced statistical methods, such as multivariate regression and nonparametric trend detection, are typically used to draw statistically sound conclusions for future climatology trends. However, note that the basic assumption of stationarity must hold: statistical relationships learned from the data at hand must remain unchanged in the future; otherwise, the projected trends will be biased. If abrupt, large-scale, nonlinear changes occur in the climate system, statistical extrapolation will fail.

Model-based projection follows a different strategy from statistical extrapolation. Using physically based governing equations, sophisticated numerical models were developed to simulate the climatology of the entire Earth system. The models are extensions of weather forecasting models, combined with other oceanic and surface hydrologic components to portray the major mass and energy exchange mechanisms of the Earth. By specifying the main climate forcings (e.g., greenhouse gas [GHG] and aerosol concentrations), centuries-long simulations were performed on large computer clusters. Simulated variables such as temperature, precipitation, and wind can then be used as inputs to hydrologic models to predict streamflow for both historical and future time periods. Although GCMs provide physically based simulations of climate at the regional scale, there is often considerable bias in comparison with observations; and there is also a need for spatial downscaling to correct mismatches in the scale between different models (e.g., GCMs at 200 km resolution and hydrologic models at 12 km resolution). For applications that are sensitive to the absolute value of streamflow (such as hydropower simulation), careful bias correction and downscaling of climate model simulations are required to achieve acceptable results. Bias correction of hydrologic model simulations may also be required.

No single approach has been recognized as fully adequate for climate change impact assessment (Fowler et al., 2007). The most appropriate methodology and strategy will depend on the questions at hand and could be different for agencies and responsibilities (Lettenmaier et al., 1999; Brekke et al., 2011). Given the fundamental limitation of statistical extrapolation, model-based simulation is adopted as the starting point to support the 9505 quantitative assessment. To make the climate model output feasible for engineering applications, a series of procedures is followed (see Figure 2-2) to produce future projections of temperature, precipitation, and runoff for each of the PMA assessment areas. The projected runoff is then applied to the historic relationship between runoff and generation to assess the potential climate impacts on hydropower generation. In addition to the quantitative assessment performed for this report, projected trends by other studies are also documented to reveal the consensus on future climate within each PMA assessment area. The procedures of quantitative assessment are described step-by-step in this section.

2.2.1 Global Modeling

GCMs are global extensions of weather forecasting models that simulate global climate by solving the three-dimensional governing equations for the atmosphere, ocean, and land surface components of the earth system. GCMs are used in climate change assessments to simulate the evolution of long-term climate in response to increasing GHG concentrations based on physical rules. The GCMs are capable of performing centuries-long simulations of many hydro-meteorological variables, including temperature and precipitation, at subdaily resolution. Because of the high complexity, GCM experiments are very computationally demanding and usually require the support of large computer clusters. It is also nontrivial to analyze GCM output, given the large amount of data flow.

Generally, a GCM experiment includes several phases. A GCM will first run under pre-industrial climate conditions for centuries of modeling years to reach stabilization. The 20th century control run (20C3M) will then be performed, in which the observed external forcings including GHG and aerosol concentration are specified as boundary conditions to drive the GCM simulation. The trends of the 20C3M simulation may then be compared with observed trends to understand how reasonable the GCM setup and performance are. Following 20C3M, the GCM projection is performed under several different potential GHG emission scenarios (Nakicenovic et al., 2000), as suggested by the Intergovernmental Panel on Climate Change (IPCC). Several commonly explored emission scenarios include A2 (higher CO_2 emissions), A1B (moderate CO_2 emissions), and B1 (lower CO_2 emissions). A comparison between observed 1990–2008 fossil fuel emissions versus IPCC scenarios is shown in Figure 2-3 (Raupach et al., 2007). Between 2004 and 2007, the observed emissions have been consistently higher than the three commonly explored scenarios. Although observations since 2008 have shown a trend toward decreasing GHG emissions, the future projection is still toward a positive increasing trend (note: it is suspected that the recent drop in emissions may be partially caused by the global financial crisis). Although the GCM responses to emission scenarios are complicated and may not be consistent for all variables, the most well known impact is on temperature. Taking Figure 2-4 as an example, the average surface temperature anomalies (shifted by the 1999 temperature) projected by the CCSM3 GCM (Collins et al., 2006) are plotted under various scenarios. It is a consistent finding across the different modeling groups that higher emission scenarios will result in higher temperature anomalies.

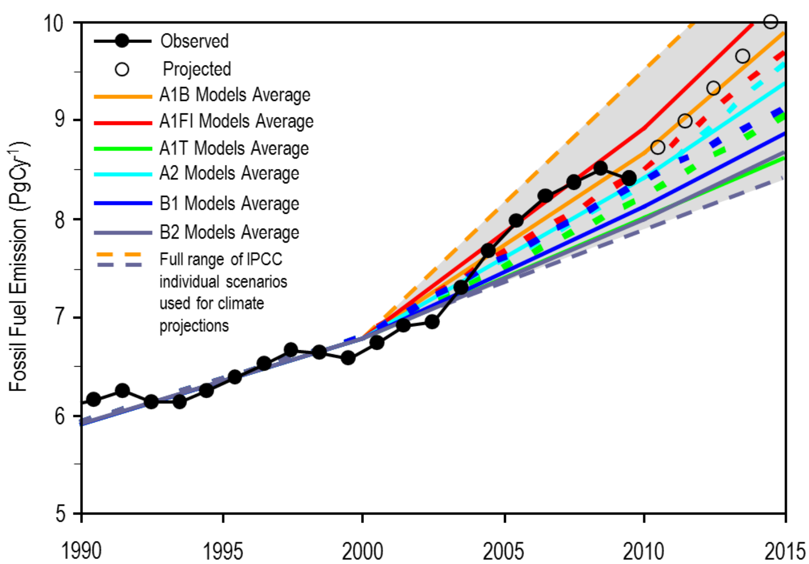

Figure 2-3. Fossil fuel emissions: actual vs. IPCC Scenarios (Raupach et al., 2007, updated 2010; courtesy of Gregg Marland).

The primary purpose of a GCM is to generate a long-term future climate outlook or projection on an aggregate basis and not to develop data or information that could be translated into area-specific weather forecasts. As a consequence, any results generated from such models should be interpreted only on a general aggregate basis and should be compared with other GCM models in terms of general direction, rates, and magnitude of climate-related changes. Since no existing weather forecasting model is currently capable of producing accurate predictive results beyond a 3 week window, it is unrealistic and unreasonable to expect that a climate model will be capable of predicting future weather and weather patterns with any degree of accuracy and/or certainty at this time. In fact, given the chaotic nature of weather forecasting models, a small perturbation in initial inputs may lead to substantial differences in the model outputs (this is sometimes termed the "butterfly effect"). Therefore, the appropriate use of GCM

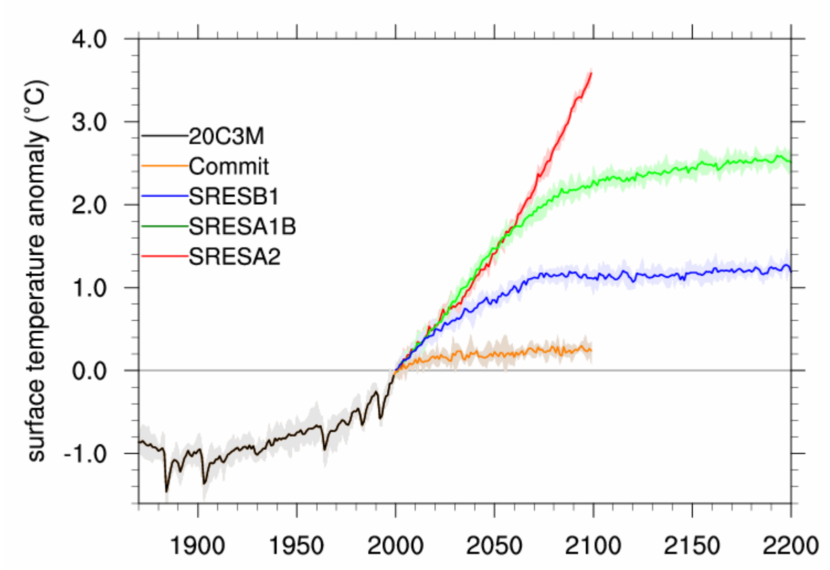

Figure 2-4. Difference in the future emission scenarios (taken from the CCSM3 modeling group).

output should focus on the general statistics over a long period of time. For instance, a prediction of the temperature at 2 p.m. on March 18, 2035, cannot be trustworthy, but a prediction of the mean temperature from 2010 to 2039 may be more credible. If a GCM is calibrated well, it should be able to capture the probabilistic distributions correctly. The same concept also applies to the 20C3M experiment. Although forced by the observed GHG and aerosol concentrations, the 20C3M experiment cannot produce the same year-to-year variability as the observed data. The goal of the 20C3M experiment is to capture the trend within the 20th century instead. In other words, a GCM acts like a global weather simulator. By operating the model iteratively with slightly different initial conditions, one may form a large number of ensemble members and examine how the climate may change from the shift of probabilistic distributions. Thus the trends and variability of climate model outputs are considered more credible than the absolute value for any specific time period.

Although the use of GCM scenarios is the most scientifically supported approach to studying climate response to changes in external forcings, significant uncertainty is expected owing to different modeling approaches, future GHG emission trajectories, spatial resolution, and initial conditions. The uncertainty spans across different modeling approaches, future GHG emission trajectories, spatial resolution, and initial conditions. Coupled atmosphere-ocean general circulation models (AOGCMs) have been developed and adopted by various working groups throughout the world. Around 23 AOGCMs were used to support the fourth IPCC assessment (AR4; IPCC, 2007). Although the general GCM pattern of some key variables is consistent (e.g., temperature), differences at local scale are significant as a result of different mechanisms, parameterization schemes, numerical techniques, and so on. AOGCMs are also challenged by several open scientific questions. For instance, clouds and aerosols have not been satisfactorily modeled, which affects the albedo rate and the global energy balance. The mechanism controlling multi-decadal oscillation has not been fully modeled. In some cases, there are no sufficient observations to support calibration of the many parameters on the global scale. The vegetation and land surface parameters are usually assumed to be static instead of evolving with time. In spite of the pending scientific challenges, the unique value of GCMs should not be overlooked. For the purpose of assessing climate change impacts on federal hydropower generation, the focus should be on how to appropriately translate GCM projections into engineering-feasible information to support planning. Those efforts are discussed in the following subsections.

2.2.2 Regional Downscaling

Although GCM provides physical-based projections of future climatology, the common GCM spatial scale (1–2° longitude/latitude per grid, approximately 200 km) is too coarse to support water resource management. However, the current simulation has been computationally exhaustive, and it is challenging to raise the spatial resolution of GCM directly. More importantly, finer GCM resolution comes with the tradeoff of fewer ensemble members, which is not preferable for studying projection uncertainty. Therefore, suitable downscaling techniques are needed to disaggregate GCM output in the interested domains. Bilinear interpolation is a simple example.

Since each GCM grid cell may cover complex terrain and non-homogeneous surface features, basic statistical interpolation will not work. Therefore, two approaches are generally used: dynamical downscaling and statistical downscaling. Regional climate modeling (RCM), which is conceptually similar to GCM but focused on specific regions, is adopted for dynamical downscaling. The GCM outputs are treated as boundary conditions during the RCM simulation. By adjusting the RCM parameters to reach a good agreement between GCM and RCM values on the boundary, RCM is used to reproduce all GCM variables at a much finer resolution. Therefore, nearly all GCM variables can be downscaled following the same set of physical governing equations. However, note that RCM simulation is also very time-consuming and requires experienced modelers to ensure that the GCM signals can be faithfully downscaled. Given the natural limitations, the number of available ensemble members is constrained. The North American Regional Climate Change Assessment Program (NARCCAP; Mearns et al., 2009) is an ongoing effort to perform comprehensive climate assessment through multiple combinations of GCM and RCM, but the selected number of GCMs is much fewer than the models adopted in the IPCC fourth assessment. Other dynamical downscaling examples can be found in Ashfaq et al. (2010).

Statistical downscaling has very different strengths and limitations. It is generally guided by historic ground observation. The observations within each GCM grid cell are aggregated to form a spatial average. The relationship (usually a ratio) between the spatial average and the observation is then developed and applied to GCM outputs to approximate the downscaled GCM values at each location with observations. Given the simpler methodology, statistical downscaling can be performed efficiently on a large number of GCM outputs and may enable the study of large member ensembles. A good example is Reclamation’s bias-corrected and spatial-downscaled (BCSD) dataset (http://gdo-dcp.ucllnl.org/downscaled_cmip3_projections/), in which more than 100 of the World Climate Research Program’s (WCRP’s) Climate Projections Coupled Model Intercomparison Project phase 3 (CMIP3) models are downscaled. The procedures of statistical downscaling can be more easily adjusted and may result in better performance in terms of evaluating statistics. However, this method cannot be applied to all variables (generally only for temperature and precipitation) and may not be justifiable on fine temporal scales (daily or subdaily). Also, there seldom are attempts to preserve the correlation structure between downscaled variables. For instance, temperature is usually downscaled independently from precipitation, and the existing correlation at local scale is not considered.

The effect of downscaling is illustrated in Figure 2-5. The CCSM3 20C3M mean annual precipitation (mm/year) from 1960 to 1999 is plotted in Figure 2-5(a) for the entire United States, and the mosaic tiles show the shapes of the CCSM3 grid cells that are overlaid. Although it is clear that the grid resolution is too coarse for local applications, it is interesting to note that CCSM3 resolution is been among the top three finest of the models in the IPCC AR4 assessment. Therefore, a reasonable downscaling approach is needed. Using the Abdues Salam Institute for Theoretical Physics Regional Climate Model version 3 (RegCM3; Pal et al., 2007), GCM values were downscaled from 1.4 to 0.125° resolution for the entire United States (Ashfaq et al., 2010). The outputs were then adjusted by bias correction (discussed in the next subsection) and are shown in Figure 2-5(b). It is clear that the spatial resolution was greatly improved after downscaling. The topographic variation in the northwest United States can be clearly seen.

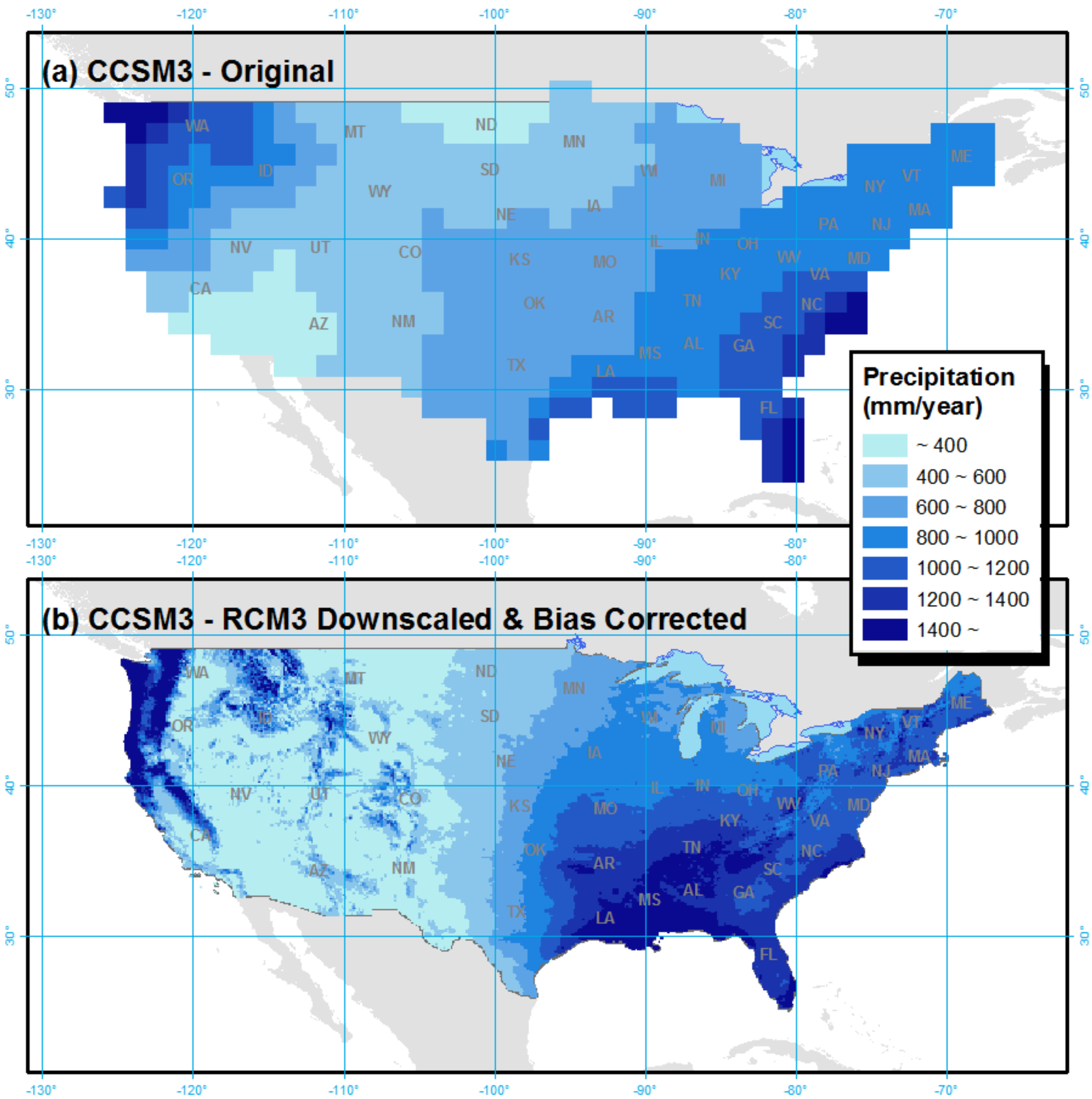

Figure 2-5. Illustration of change in resolution of climate data obtained from downscaling and bias correction (period of simulation: 1960–1999).

Given that most of the federal hydropower plants are located in mountainous regions, reasonable downscaling and bias-correction approaches are required to locally translate GCM trends to a local scale.

Note that it is not possible to generally judge between dynamical and statistical downscaling (see Fowler et al. (2007) for detailed review and discussion). It is, again, a decision depending on the nature of the problem. Given that the daily maximum/minimum temperature, precipitation, and wind speed will be needed for subsequent hydrologic modeling, dynamical downscaling is selected in the quantitative assessment. Note also that no matter which downscaling approach is chosen, there may still be considerable differences compared with ground observations. Another important step, bias correction, needs to be introduced.

2.2.3 Bias Correction

Although numerical models (including hydrologic, meteorological, climatic, and others) are the best approximations that scientists and engineers can create to simulate different problems, hardly any natural phenomenon can be fully depicted at all scales without errors. The difference between modeled and observed quantities is termed "bias." For instance, although a flood peak at a reservoir can be predicted if extreme precipitation is observed at upstream gauge stations, the accuracy of the forecast flood peak height and timing can hardly be controlled within a 1% range because of the limited precision of observation and model capability. Bias tends to magnify with lead time, size of study domain, and complexity of system. Local bias is also expected to be more significant than the average system bias. As a result, a large bias is expected in complicated systems such as GCM; hence raw GCM projections cannot be applied directly for impact assessment. Although it may seem that this issue could be resolved naturally by improving GCM and RCM parameterization, that goal is unlikely to be achieved because of the model complexity. Modelers may also want to avoid over-parameterization and over-fitting, which could lead to worse projections in the future. Therefore, the statistical procedure of bias correction is typically used to adjust the scale of model projections (see Wood et al., 2002).

The goal of bias correction is to re-scale model-projected values to observed ones while preserving projected trends. Bias correction can be performed only when there is sufficient overlap between observation and model projections. The overlaid values are used to develop a transformation function between modeled and observed values, and the function is then used to adjust future model projections. The concept of bias correction is illustrated in Figure 2-6. For one grid cell within the system, the red dots in Figure 2-6(a) show the cumulative probability built from local observation, and the blue dots indicate the simulated values by a numerical model. In this grid cell, the model tends to overpredict the values, and the systematic bias is expected to persist in future projections. Using Figure 2-6(a) as a reference, a transformation function can be developed by equating values with the same cumulative probability values. Using the transformation function, the raw model projection shown in blue in Figure 2-6(b) can be rescaled and shown in red. Following this transformation, the general trend is preserved, and the adjusted outputs will have the same probability distribution as the observed ones. Common bias-correction techniques can be found in Wood et al. (2002) and Ashfaq et al. (2010). In this assessment, the RCM-downscaled daily maximum/minimum temperature and total precipitation are bias-corrected by the PRISM dataset following the method proposed by Ashfaq et al. (2010).

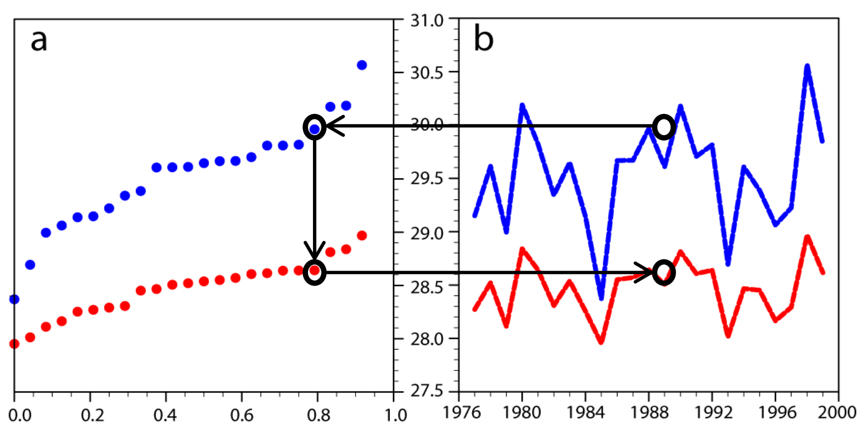

Figure 2-6. Illustration of bias-correction process (blue line and dots represent model results for the observed period, and red represents historical observations).

2.2.4 Hydrologic Modeling

After regional downscaling and bias correction, temperature and precipitation as projected by GCMs are available as gridded products at the hydrologic model resolution of 1/8 degree (~12 km). The next technical question is then more familiar to the water resources community—how much streamflow will be available for hydropower generation? It is a standard question that requires the use of hydrologic models. Depending on the watershed size, topography, soil infiltration, vegetation, antecedent moisture condition, snowpack, and evaporation, part of the rainfall becomes streamflow and is stored at reservoirs for water usage and hydropower generation.

Hydrologic models are designed to simulate the response of watersheds to rainfall. Rainfall events are usually treated as known, and the main objective is to synthesize streamflow to be as close as possible to observed streamflow. Given the strong linkage to landscape and topography, the hydrologic models are usually very diverse and location-specific. Hydrologic models could be empirical, conceptual, or physical-based, as long as a good performance can be developed and validated. Since hydrologic models are typically used to support hydraulic structure design, especially under extreme events, high accuracy is required. Therefore, the concept, purpose, and scale of hydrologic models are very different from those of GCMs. One may state that GCMs are more scientifically oriented, with less emphasis on local accuracy, whereas hydrologic models are more engineering-oriented, with less emphasis on large-scale interactions.

To assess federal hydropower in a nationally consistent manner, a general hydrologic modeling approach is required. Therefore, the widely used Variable Infiltration Capacity (VIC) model (Maurer et al., 2002) was chosen for this assessment. By taking daily precipitation, maximum/minimum temperature, and wind speed as inputs, VIC computed potential evapotranspiration through the Penman Monteith approach (Maidment, 1993). Other forcings, including short-wave and long-wave radiation, relative humidity, and vapor pressure, are also estimated within the model as a parameterization of maximum/minimum temperature. The water and energy balance are solved for multiple elevation bands and vegetation types, allowing the model to capture the subgrid-scale variability of these land surface features. For each individual grid cell, VIC estimated the water budget of daily evaporation, snowpack, moisture storage, faster-response surface runoff, and slower-response baseflow. Another independent routing model can be used to simulate streamflow at locations of interest, but it was sometimes not performed (e.g., Demaria et al., 2007). In this assessment, the total annual and seasonal runoff of each PMA region are computed by summing both baseflow and surface runoff directly. VIC version 4.1.1 was adopted in this assessment, in which the detailed setup can be referred to Ashfaq et al. (2010). Note that VIC is also used to support the Section 9503 Assessment of Reclamation watersheds.

2.2.5 9505 Ensemble

Given the specific focus on federal hydropower, note that the assessment period of interest is different from that of many climate change studies. Although most climate change assessments focus on projections after 2040 or near the end of the 21st century, near-future projection is more useful for PMA operation. For instance, to ensure that reasonable long-term power contracts can be established, especially considering possible drought-induced shortfalls, the potential climate change and variability of the following 30 years will be more informative for decision making than longer-term projections. Aging of dam structures, hydroelectric generators, and transmission facilities, and loss of reservoir capacity from sedimentation may result in fundamental changes to the system sooner than far-future climate change will. Rapid improvement of GCMs could soon lead to refined and different modeling results. Given these considerations, the first 9505 Assessment focuses on the near-term and mid-term future (until 2039) where the risk lies currently. The assessment period and methodology will be updated and improved for future assessments.

As one overall goal of SWA is to estimate the risk of climate change comprehensively, the 9505 Assessment provides an alternative for the downscaling approach. Instead of using statistics-based approaches as do other studies (e.g., Reclamation, 2011c and RMJOC, 2010), dynamical downscaling was pursued. For instance, the 9503 Assessment is mainly based on the BCSD Data Archive (Maurer et al., 2007), which includes a comprehensive set of GCM outputs with three different future emission scenarios (A2, A1B, B1) downscaled using a statistical approach proposed by Wood et al. (2002). Since only monthly mean temperature and precipitation were available from the BCSD Archive, additional steps (Reclamation, 2011b) must be taken to synthesize daily meteorological events before the climate projection can be fed to the VIC model. Without introducing additional uncertainties from the synthesis of meteorological events, dynamical downscaling was able to produce daily-scale projections directly and was hence preferred in this 9505 Assessment. The difference between dynamical and statistical downscaling can provide additional insights into the methodological uncertainties.

Given the desire to conduct dynamical downscaling, selection of climate projections was constricted, since not every GCM modeling group provided sufficient GCM output to support dynamical downscaling. Five CCSM3 projections under the A1B emission scenario were dynamically downscaled by RegCM3 and bias-corrected by PRISM datasets. The projected daily temperature and precipitation were then fed into VIC to simulate runoff and baseflow. The five sets of simulation are termed the 9505 ensemble and were used in the rest of the assessment. Technical details are outlined in Ashfaq et al. (2010). Although the daily-resolution climate projection could be generated naturally through dynamical downscaling, this modeling approach was very computationally intensive: the entire simulation took around 2.5 million CPU hours (i.e., the number of CPU cores multiplied by the computation time) on the cluster computer. Therefore, the tradeoff is that fewer ensemble members are included in the 9505 Assessment. More time and resources would be required to increase the number of ensemble members in the future assessment.

To visualize the difference, the projected changes in all 9505 and 9503 assessment simulations from 1960–1999 to 2000–2039 are illustrated in Figure 2-7. The average changes in temperature (in °F) and precipitation (in %) in the entire United States are shown on the two axes. The median of the BCSD simulation is marked by dashed lines. All 112 of the 9503 Assessment results are indicated by green dots, and five of the 9505 Assessment results are indicated by blue stars. Since the BCSD contained various models and three emission scenarios, a considerable spread was expected. Within the period of interest, the average US annual temperature is projected to increase by around 1–3°F, with all models showing signs of increase. On the other hand, the precipitation projections are more diverse, ranging from a 4% decrease to a 7% increase. The five 9505 Assessment simulations are positioned around the center of the BCSD, with a maximum/minimum range across both sides of the BCSD medians. Therefore, the main range of mean variability should be captured, even though the 9505 ensemble contained only five simulations. However, note that Figure 2-7 serves only as a simplified comparison with the long-term national mean and has no implications for local trends and extreme events. Different patterns are expected for smaller local regions. Given that bias correction and spatial downscaling were performed in both the 9503 and 9505 Assessment datasets, projected changes may be different in studies based on raw GCM outputs.

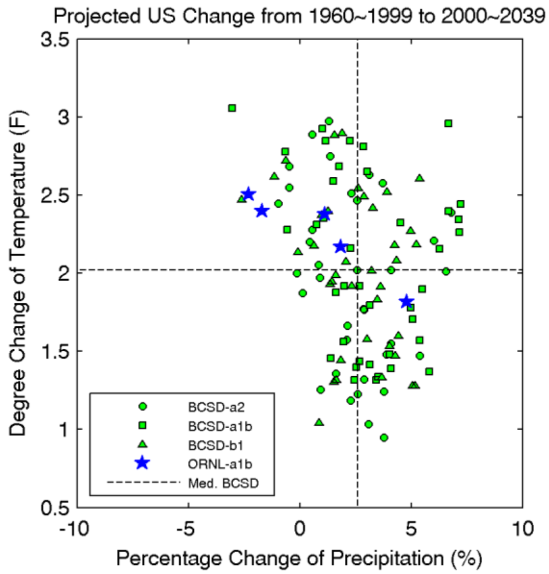

Figure 2-7. Comparison of the 9505 ensemble data with other model outputs.

In the following PMA sections, the 9505 ensemble is analyzed in various steps for each of the assessment areas. The projections of mean annual, spring, summer, fall, and winter temperature, precipitation, and runoff changes for the near-term period (2010–2024) and mid-term period (2025–2039) (with respect to the 1960–1999 baseline) are illustrated (e.g., Figure 3-4), and the ensemble minimum, median, and maximum are shown. In addition, the cumulative distributions of observed and simulated temperature, rainfall, and runoff are illustrated in Appendix E for each assessment area. To check the statistical significance of a simulated trend (increasing or decreasing) , the Mann-Kendall test was performed with a 95% confidence level for annual, spring, summer, fall, and winter temperature, precipitation, and runoff for the entire 1960–2039 simulation. The results of the trend detection (see Table 7-1 in Section 7) can help filter some noisy signals within the simulations. Given that trend analysis is very sensitive to the selection of starting and ending periods (see Liebmann et al., 2010) and the 40 year 9505 observations may not be long enough to support meaningful evaluation, trend detection was not performed on the observations in this first assessment.

Regarding the projection of future extremes, the changes in the frequency of dry, normal, and wet water years over both future 15 year periods, based upon projected runoff, are illustrated in each PMA section (see, e.g., Figure 3-5). Water year types are defined by annual runoff values for the baseline period (1960–1999). Annual runoff values less than the lower 20% quantile during the baseline period are designated as dry years and values greater than the upper 80% quantile are designated as wet years. The blue bars are references to baseline frequency. For example, a change in the dry year frequency from 0.3 to 0.4 in BPA-1 area (see Figure 3-5a) would mean one more dry year per decade. In addition, the 10 year return level quantiles (or 10% quantiles) of seasonal low runoff are presented for both baseline and future projection periods. The 10 year low runoff indicates, statistically, the amount of low flow that may occur every 10 years on average. It is a commonly used index to identify hydrologic droughts.

By combining the annual runoff-generation relationship (see Figure 3-3) for each assessment area and the projection of future runoff (see Figure 3-4), annual hydropower generation can be estimated (see, e.g., Figure 3-6). The average simulated generation during the baseline period was computed for each of the PMA assessment areas, along with their corresponding projected changes in the two future periods, in which the ensemble minimum, median, and maximum are shown. To avoid bias embedded in the VIC modeling, bias correction was performed again for the simulated annual runoff by using the USGS

WaterWatch observed runoff. Detailed numbers can be found in Appendix H. The minimum and maximum annual hydropower generation during the observed recent 20 year period (1989–2008), simulated near-term period (2010–2024), and simulated mid-term period (2025–2039) are also summarized in Appendix H. Detailed cumulative distributions of observed and simulated annual generation are illustrated in Appendix I for each of the PMA assessment areas.

In addition to the quantitative assessment, a number of important global changes will likely affect hydropower generation resources that are not included in the simulation models used here for quantitative assessment. For example, the available climate change models do not account for changes in population distribution over time, land-use change, or changes in consumptive water use for growing cities, industry, or agriculture. Finer-scale issues such as air-temperature–induced changes in water quality or aquatic habitat are not explicitly modeled in this first 9505 Assessment, nor are changes in reservoir evaporation. A literature review and synthesis is therefore presented in addition to the climate modeling to address other, nonmodeled, climate impacts. Assessments performed by other major research groups are also included to report the current agreement or disagreement regarding future climate change trends for each region.

3. THE BONNEVILLE REGION

This section describes SWA Section 9505 Assessment results for the Bonneville region and the federal hydropower projects located there. The section is organized into four subsections. The first explains how the region was subdivided into areas of analysis and presents information on the region's federal hydropower system, power marketing by Bonneville, and major water management issues within the region. The second subsection describes existing hydrology and generation patterns in the region under the current climate (i.e., the baseline for comparison to climate change projections). The third contains results of the climate change projection that was done for this Section 9505 Assessment, along with a literature-review comparison to climate studies by others. The fourth subsection focuses on potential changes to federal hydropower generation under the projected future climate, and possible adaptation options, responding to the effects of climate change.

3.1 REGIONAL CHARACTERISTICS

Bonneville is the largest PMA in the United States in terms of the number of federal hydropower projects (31), total installed capacity (20,516 MW), and average annual generation (77 billion kWh). For the purposes of the 9505 Assessment, the Bonneville region is subdivided into four major areas of analysis (Figure 3-1 and Appendix B):

- Bonneville Area 1 (BPA-1): the Upper Columbia River upstream, including Grand Coulee Dam
- Bonneville Area 2 (BPA-2): the Snake River upstream of its confluence with the Columbia
- Bonneville Area 3 (BPA-3): the Lower and Mid Columbia River, from Bonneville Dam upstream to the tailwater of Grand Coulee
- Bonneville Area 4 (BPA-4): Cascade Mountain projects in southeastern Oregon

3.1.1 Area of Analysis

All of the federal hydropower projects in the Bonneville region are managed as a single system, the FCRPS (Section 3.1.2). The river drainages providing water to the FCRPS projects cover large portions of the states of Washington and Oregon, almost all of Idaho, small parts of Montana and Wyoming, and almost 39,000 mile^2 in Canada.

The first of the 9505 Assessment areas of analysis in the Bonneville region, BPA-1, is the Upper Columbia River system. It includes the main stem of the Columbia River and its tributaries above and including Grand Coulee Dam. The total drainage area for BPA-1 is 75,058 mile^2, 45% of which is in Canada. The major tributaries where federal hydropower plants are located are the Pend Oreille, Kootenai, and Flathead Rivers. The watershed of this uppermost area is predominantly mountainous, with a median elevation of 4,600 feet above mean sea level (ft amsl) and maximum elevations exceeding 11,000 ft in the Canadian Rockies. The dominant land cover is evergreen (69%) and deciduous (13%) needleleaf forest with minor amounts of grasslands and mixed forests (6% each).

The second area of analysis, BPA-2, is the Snake River Basin, upstream of the Columbia–Snake confluence. The total drainage area for BPA-2 is approximately 108,000 mile^2, most of which is in the state of Idaho. Federal hydropower plants are located on the main stem of the lower and upper Snake River, as well as on some of its major tributaries, the Clearwater, Boise, and Deadwood Rivers. Topography here is a mix of high plains and mountains, with a median elevation of 5,112 ft amsl and maximum of over 12,000 ft amsl. Land cover is relatively diverse with 52% grassland, 27% evergreen forest, 12% cropland, and 9% closed shrubland.

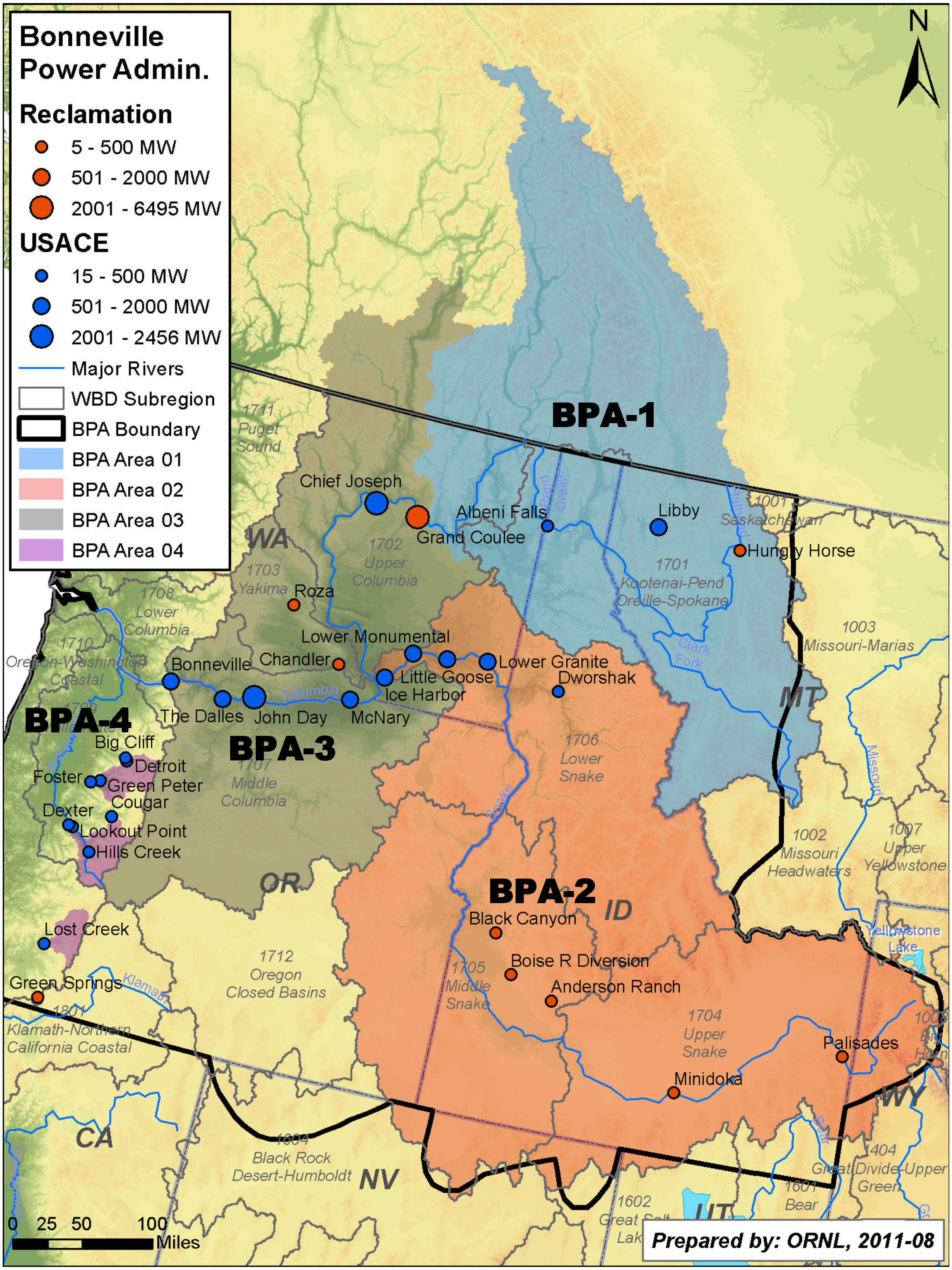

Figure 3-1. Map of the federal hydropower projects and analysis areas in the Bonneville region.

The third area of analysis, BPA-3, is the mid and lower Columbia River from the most downstream federal hydropower plant, Bonneville Dam, up to the tailwater of Grand Coulee. The drainage area of BPA-3 is 242,199 mile^2, including both the BPA-1 and BPA-2 areas. Seventeen percent of this area is in Canada, where water management is controlled by international treaty. All of the federal hydropower projects in BPA-3 are on the main stem of the Columbia River. Topography in the watershed is a mix of high plains and mountains. Median elevation is 2,927 ft amsl and the highest elevations are upstream in other areas (BPA-1 and BPA-2). Land cover in BPA-3 is 52% closed shrubland, 38% grasslands, 14% cropland, and 7% woody savanna.

The fourth Bonneville area of analysis, BPA-4, includes four separate watersheds on the western slope of the Cascade Mountains of Oregon. Two of these are in the Willamette River Basin and two are farther south on other coastal rivers. The aggregate median elevation of this area is 3,773 ft amsl and the maximum elevation in this part of the Cascade Range is 9,459 ft amsl. Land cover is 94% evergreen needleleaf forest.

3.1.2 Federal Hydropower System

The Columbia River Basin is one of the richest regions of the United States in terms of water resources and the most heavily developed region for hydropower. The four states of Washington, Oregon, Idaho, and Montana are home to a total of 34,600 MW of installed hydropower capacity at federal and nonfederal projects; this total accounts for 35% of the total US installed hydropower capacity. The federal projects in the region are owned and operated by either USACE or Reclamation (Table 3-1). Some of the largest hydropower projects in the United States are located on the Columbia River. For example, Reclamation’s Grand Coulee Dam is the largest federal hydropower project in the United States with an installed conventional capacity of 6,405 MW and another 314 MW of pumped-storage capacity. The largest USACE hydropower project is the 2,456-MW Chief Joseph project, which is immediately downstream of Grand Coulee (a full listing of the federal projects in the Bonneville region is located in Appendix B).

Table 3-1. Hydropower distribution among the areas of analysis in the Bonneville region

Area no.	Major watersheds	Number of plants			Total installed capacity[a] (MW)	Average annual generation[b] (million kWh/year)
		USACE	Reclamation	Total		
BPA-1	Upper Columbia	2	2	4	7804	23120
BPA-2	Snake River	5	5	10	3692	12518
BPA-3	Mid-Lower Columbia	5	2	7	8544	39808
BPA-4	Cascade Mountains	9	1	10	475	1856
Total		**21**	**10**	**31**	**20515**	**77302**

[a] EIA 2008 total nameplate capacity. Includes both conventional hydro and pumped-storage.
[b] EIA and Reclamation average annual generation from October 1970 to September 2008 (fiscal year). Conventional hydro only.

The federal hydropower projects in the Bonneville region have an average age of 48 years. The oldest USACE project is Bonneville Dam, which began operation in 1938; the last USACE project constructed in the region was Lost Creek in 1977. Reclamation’s projects in this region were constructed between

1909 (Minidoka) and 1964 (Green Springs). Aging infrastructure and rising costs for O&M are a serious concern here, as they are in other regions (Sale, 2011).

The large federal system in Bonneville's region plays an important role in supporting other renewable energy development, such as wind and solar; but it can only do so if it maintains its operational flexibility. Recent Congressional testimony by BPA illustrates this well, describing how the existing hydropower system in the Columbia River is being managed to serve as a virtual storage battery of energy that can be used when needed to balance the variable output from wind in the region (Mainzer, 2009). As intermittent renewables like wind and solar grow throughout the country, the need for load balancing from hydropower will also grow. However, the operational flexibility of USACE hydropower projects is currently decreasing owing to a combination of deteriorating equipment conditions and new environmental protection requirements (ecological flow needs and fish passage requirements).

3.1.3 Multi-Purpose Water Management Issues

Almost all of the hydropower plants in the Bonneville region are part of multipurpose water developments. Hydropower operates in a complex relationship with other water development purposes, including flood control, navigation, and water supply for agricultural irrigation, as well as for municipal and industrial uses. Environmental water needs and recreational water uses are also very important in the region.

Much of the water flowing through the Columbia River originates in Canadian watersheds; therefore, the basin is managed as an international resource. In 1909, the Boundary Waters Treaty was established between the United States and Canada to develop principles and procedures to manage waters in the basin. An International Joint Commission (IJC) was created to study and resolve issues relating to joint use of boundary waters. Since then, the IJC has been responsible for coordinating the Columbia River Treaty (CRT), under which three large storage reservoirs (Mica, Duncan, and Keenleyside Dams) were constructed in Canada and another (Libby Dam) was built in the United States The joint operation of these upstream facilities provides hundreds of millions of dollars of benefits per year in terms of flood control, hydropower, and other benefits. The current CRT has two provisions that may change in the year 2024. These provisions may significantly impact the benefits of the CRT. First, the flood control space in CRT projects expires in September 2024. Second, the CRT may be terminated by either the United States or Canada as early as 2024, but only with a written notice to terminate with a minimum 10 years advance notice. The 10 year notice requirement has both the United States and Canada actively working to determine whether a termination notice should be delivered as early as 2014. Extensive studies and negotiations, called the 2014/2024 Columbia River Treaty Review, are going on now that may lead to a termination notice of the CRT or else agreement to continue it under the current terms or explore new provisions (USACE and BPA, 2009). The outcome of the CRT Review may eventually change the magnitude and timing of water available for the federal hydropower system on the US side of the border, independent of any effects of climate change.

Another key issue dominating water management in the Columbia River is ecosystem restoration and mitigation, principally related to anadromous salmon. By the 1970s, it was clear that salmon populations in the Columbia River were suffering from a number of environmental impacts, including hydropower development. Today, 13 populations of salmon and steelhead in the Columbia River are listed as threatened or endangered under the Endangered Species Act, requiring a broad array of mitigation actions. These actions have been expensive and controversial, and the effectiveness of many is as yet unproven. The Biological Opinion that defines required mitigation actions has been under continuous legal challenge, review, and revision for most of the past decade. The Northwest Power Planning and Conservation Council (NPPCC), a multi-state organization established by Congress, develops and maintains a regional power plan and a fish and wildlife program to balance the Northwest's environment and energy needs (NPPCC, 2010).

Bonneville, USACE, and Reclamation maintain a River Management Joint Operations Committee (RMJOC) through which they cooperate on long-term planning and operational decisions that affect the Columbia and Snake River Basins. The RMJOC is also an important regional forum for interactions with a much larger group of water resources stakeholders, including the US Fish and Wildlife Service, NOAA Fisheries Service, NPPCC, BC-Hydro, and Columbia River Inter-Tribal Fish Commission. One of RMJOC's most active efforts right now is focused on understanding the potential effects of climate change, as explained in Section 3.3.2.

3.1.4 Power Marketing by Bonneville

Bonneville markets power from the 31 federal hydropower projects that make up the FCRPS, owned and operated by the USACE and Reclamation. It also has acquired all of the generating capability of a nuclear plant (Energy Northwest's Columbia Generating Station), as well as output from some small nonfederal hydropower projects and wind plants. Bonneville also maintains 15,238 miles of transmission lines. Bonneville's traditional regional customers include 135 preference customers (57 cooperatives, 42 municipalities, 29 public utility districts and 7 federal agencies), 6 IOUs, 3 direct service industrial (DSI) customers (two aluminum smelters and a paper mill), 2 tribal utilities and a port district (Bonneville, 2009b). Bonneville also markets surplus power to purchasers both within and outside the Pacific Northwest (PNW).

Bonneville was created by enactment of the Bonneville Project Act of 1937. In 1974, Congress passed the Federal Columbia River Transmission System Act which made Bonneville self-financed by authorizing it to use proceeds from power sales and transmission revenues, instead of appropriations, to cover O&M expenses. Then the Energy Policy Act of 1992 gave Bonneville authority to transfer some of its revenues from power sales directly to USACE. Bonneville holds three types of debt: appropriated (pre-1974) debt associated with construction of USACE hydropower facilities; long-term debt (acquired through $7.7 billion in borrowing authority from the Treasury), which primarily funds the transmission system; and nonfederal debt which is linked primarily to financing of the Washington Public Power Supply System (now Energy Northwest) nuclear projects.[3] Bonneville's borrowing authority has been expanded several times since it was first granted in 1974. In 2009, the American Recovery and Reinvestment Act increased it by $3.25 billion (US House of Representatives, 2009).

Bonneville conducts revenue requirement studies (RRS) and power repayment studies. Rates are established based on the RRS, but if the revenue requirements are not sufficient to meet repayment study obligations, the revenue requirements are adjusted upward to meet repayment requirements. Bonneville's target is to set rates that will result in a 95% probability that payments to the Treasury (last creditor in line) will be made on time and in full. In its RRS, Bonneville takes into account several types of risk: weather-related, asset performance, market prices, general economic conditions, and costs of environmental compliance (Bonneville, 2009d). Bonneville uses conservative planning assumptions (hydrological conditions like those in its worst year, 1937) when evaluating the adequacy of its resource portfolio to satisfy all of its contracted requirements (Bonneville, 2009d). To cope with variability in hydro resources and customer utility loads, and to ensure the adequacy of its firm power supply, Bonneville uses multiple schemes: power acquired from the market, conservation and load management programs; power exchanges with other regions; and water previously stored in nonfederal storage. If,

[3] BPA accumulated this debt in the mid-1970s when it guaranteed the debt needed by the Washington Public Power Supply System for its nuclear projects. This group of utilities obtained permits and initiated construction of five nuclear plants, of which only one was completed and became operational.

taking into account all of these options, Bonneville determines that its resources will be insufficient on a planning basis, it has statutory authority to implement its insufficiency and allocations methodology in order to distribute the available resources among its customers (Federal Register, 1996). Customers must be given at least a 5 year notice of any reductions to their contracted allocations and should be informed of the size and duration of the reduction. Under such conditions, additional statutory requirements may be imposed on Bonneville's customers.

Firm power is electric power (capacity and energy) that Bonneville makes continuously available, except for events of force majeure. Firm power is often purchased by Bonneville's regional customers, including DSIs, to meet their firm power net requirement needs. Surplus firm power is the amount of power that Bonneville has available after meeting its power sales contract obligations to serve the needs of preference, IOU, and DSI customers. Power generated over and above that which is needed to supply Bonneville's firm power obligations is marketed throughout the western United States and Canada as surplus power. In average hydro years, revenues from surplus sales account for 10 to 20% of Bonneville's power revenues. Rates are generally set at a level that assumes average revenues from surplus power sales will be realized.

Wholesale power rates during the FY 2010–2011 period were increased by about 7% relative to the prior power rates. This was the first power rate increase since 2002 and was due to lower than expected revenues and increased capital and maintenance costs to improve safety, performance, and reliability in the hydropower plants as well as the nuclear station (Bonneville, 2009a). The wholesale power rate for FY 2012 will increase by an additional 7.8%. Forecasts of a continued increasing trend in generation maintenance and other expenses are cited to justify this rate increase (Bonneville, 2010a). Fish and wildlife mitigation costs stand out among the total costs that Bonneville customers must cover. They amount to $800 million per year, which means that approximately 30% of ratepayer dollars in this system goes toward environmental compliance.

In December 2008, Bonneville signed long-term wholesale power sales contracts for 2012–2028, with all of its preference customers adopting a new tiered-rate structure (Bonneville, 2009a). Under tiered rates, the following rules will apply:

- Preference customers pay lower Tier 1 rates for power produced by the existing federal system. Tier 1 rates have been designed to send better price signals to Bonneville's customers by charging higher rates for power required in excess of that available from the FCRPS.

- For load growth beyond what can be served with existing resources, customers can choose to secure their power from other suppliers or to pay Bonneville a higher Tier 2 rate based on Bonneville's costs to secure power from new sources (Bonneville, 2010b).

As of FY 2010, there are five basic power rate schedules (applicable to the whole service area, no regional rate differentiations) with rates summarized in Table 3-2 (Bonneville, 2009c). Demand rates, which apply to each kilowatt of reserved capacity, and energy rates, for each kWh actually consumed, vary for each month. Table 3-2 displays only the minimum and maximum monthly rates. Each rate schedule applies to multiple products (e.g., full service product, actual partial service product, block product) with specific billing factors and adjustments.

Priority Firm Power Rate (PF): The PF rate applies to sales of power to preference customers and to federal agencies. Historically, the PF rate is Bonneville's lowest cost-based rate. Sales obligations to PF customers accounted for 77% of the total firm obligations (average 8,896 MW) identified in the 2010 Load and Resources Study. In addition, participants in the Residential Exchange Program make payments to eligible PNW utilities based on a paper exchange of power. Bonneville "purchases" power from each

Table 3-2. Rate structures for Bonneville

	Monthly demand rate ($/kW)	Monthly energy rate (mills/kWh)	Load variance rate (mills/kWh)
Priority firm	June—1.32 December—2.30	HLH[a] (June) – 19.95 HLH (December) – 34.96 LLH[a] (June) – 10.59 LLH (December) – 25.65	0.49
New resource firm Power rate	June—1.32 December—2.30	HLH (June) – 64.32 HLH (December) – 79.32 LLH (May) – 45.98 LLH (September) – 66.54	0.49
Industrial firm power rate	June—1.32 December—2.30	HLH (June) – 31.18 HLH (January) – 38.46 LLH (May) – 22.29 LLH (September) – 32.26	0.49

[a]HLH stands for "heavy load hours" (the on-peak period from hour ending at 7 a.m. to hour ending at 10 p.m. Monday through Saturday) and LLH stands for "light load hours." Load variance is defined as the variability in hour-to-hour or month-to-month energy consumption within the Bonneville customer's system.

participant at the average cost of all of the participant's resources and each participant "purchases" power from Bonneville at a PF exchange rate. The difference in rates results in a payment by Bonneville to the participant, and the proceeds are required to be passed on to the participant's residential and small farm consumers.

***New Resource Firm Power Rate* (NR):** for the contract purchase of Firm Power by IOUs to serve any requirement load they elect to place on Bonneville. It is also applicable to preference customers to the extent that such power is used to serve any new large single load, as defined by statute. No power sales are forecast under this schedule during the current rate period or in the foreseeable future.

***Industrial Firm Power Rate* (IP):** The IP rate is for Bonneville's DSI customers for firm power to be used in their industrial operations in the PNW. Sales to two of the three eligible industries amount to an average of about 340 MW for the current rate period.

***Firm Power Products and Services Rate* (FPS):** Products and services under the FPS schedule are discretionary short-term sales at rates mutually agreeable to Bonneville and the purchaser.

***General Transfer Agreement Service Rates* (GTA):** These rates apply to low-voltage delivery of federal power provided under General Transfer Agreements or other nonfederal transmission service agreements.

One of Bonneville's products, available only to preference customers under the PF rate, is the slice product by which a purchaser pays a fixed percentage of Bonneville's power costs in exchange for a fixed percentage of FCRPS generation and capabilities. The maximum percentage of the slice system capability that an eligible customer may purchase is the ratio of *net entitlement* (annual average quantity of the customer's regional net firm load requirement calculated during the subscription process) to *total inventory* (annual average firm energy load carrying capability for federal system resources) (Bonneville, 1999). The customer may purchase any percentage up to the maximum percentage, and it will be fixed for the term of the contract (10 years). This product has been renewed through 2028 under Regional Dialogue contracts. The slice product moves the risk of variable hydro conditions from Bonneville to slice purchasers. It is shaped to FCPRS generation rather than to customer loads. Slice purchasers accept the risk of fluctuations in output and accept responsibility for managing their percentage share of the federal system output to serve their loads. In return, they have limited access to the same federal system flexibilities available to Bonneville in order to fulfill its load-following obligations. Deliveries under the slice system are based on power generated by a specific set of federal resources, which amounts to 22.63% of the total system resources.

During 2009, the January–July hydro runoff in the FCRPS was 84% of the rolling 30-year average, and Bonneville obtained its lowest revenues from surplus power sales since 2000–2001. Power Services revenues were below expectations (Bonneville, 2009a). During 2010, the January–July hydro runoff in the FCRPS was 79% of the rolling 30-year average and Bonneville had very little surplus power to sell. Since surplus power sales typically account for 20% of the total Bonneville power revenue, Power Services revenues were below the objective level for that year. For FY 2010, payments on federal appropriations were $261,376,000, payments on borrowings from the US Treasury were $462,878,000, and payments for nonfederal debt were $649,249,000. Despite the situation of lower-than-average runoff for FY 2010 as a whole, Bonneville experienced problems of oversupply in June 2010. Dam operators had to spill water to control the situation, creating not only a waste of power but also environmental concerns, as excessive spillage might harm fish. Considering the staggering pace at which wind capacity has been added in this region (25 MW of installed capacity in 1998, 1600 MW by the end of 2008, and 3379 MW by the end of 2010) and the plans to continue that trend, it is to be expected that similar oversupply situations will arise in future years (US House of Representatives, 2011). Such occurrences highlight that the challenges in managing this federal hydropower system might arise from both low water availability and high water availability conditions.

3.2 WATER AVAILABILITY AND HYDROPOWER GENERATION

3.2.1 Observed Hydrology and Generation

The 1971–2008 average annual, spring (March, April, and May), summer (June, July, and August), fall (September, October, November), and winter (December, January, and February) temperature, precipitation, runoff and generation are summarized in Table 3-3 for the four Bonneville assessment areas. Using drainage area as a weighting factor, the average across the entire Bonneville region was also computed. The mean annual Bonneville precipitation and runoff are 25.2 and 12.9 in., respectively (computed from the datasets described in Section 2 in this report). Bonneville has the third-highest precipitation (first, Southeastern: 52.0 in.; second, Southwestern 29.0 in.) and the second-highest runoff (first, Southeastern: 19.8 in.) among the four PMAs. Given its lower temperature, the evaporation is the lowest, resulting in the highest runoff-to-precipitation ratio (51%). With the construction of several large reservoirs (e.g., Grand Coulee), Bonneville has the most abundant hydrologic resource for water supply and hydropower generation.

In addition, the cumulative distributions of observed monthly temperature, rainfall, runoff, and generation are illustrated in Appendix D for each of the Bonneville assessment areas. On the graphs in Appendix D, solid black lines represent the distribution curves across the entire year, dashed green lines represent the spring months, dashed red lines the summer months, dashed black lines the fall months, and dotted blue lines the winter months. Note that in computing regional averages of temperature, precipitation, and runoff for BPA-3, the entire upstream areas were considered (BPA-1 – BPA-3) instead of just BPA-3 itself. The same approach is used in Section 3.3.1 in deriving climate projections for BPA-3.

Table 3-3. Summary of the 1971-2008 average temperature, precipitation, runoff, and generation for the Bonneville assessment areas

	Temperature (°F)					Precipitation (inches)				
	Annual	Spring[a]	Summer[a]	Fall[a]	Winter[a]	Annual	Spring	Summer	Fall	Winter
BPA-1	38	38	57	38	20	31.0	7.2	6.1	7.7	10.0
BPA-2	43	42	62	44	25	21.9	6.2	3.4	5.1	7.2
BPA-3	42	41	61	43	25	24.7	6.3	4.1	6.0	8.3
BPA-4[b]	46	43	59	47	34	67.0	16.9	4.6	17.5	28.0
BPA	42	41	61	43	25	25.2	6.4	4.1	6.1	8.6
	Runoff (inches)					**Generation (million kWh)**				
	Annual	**Spring**	**Summer**	**Fall**	**Winter**	**Annual**	**Spring**	**Summer**	**Fall**	**Winter**
BPA-1	18.2	6.2	7.6	2.3	2.1	23120	5342	6599	5089	6090
BPA-2	8.7	3.5	2.9	1.0	1.3	12518	4293	3475	2035	2715
BPA-3	12.5	4.5	4.6	1.6	1.9	39808	11318	9963	7971	10556
BPA-4[b]	46.5	11.9	6.5	10.1	18.0	1856	453	386	503	514
BPA	12.9	4.6	4.6	1.7	2.0	77302	3067	3164	1769	2307

[a] Spring includes March–May; Summer includes June–August; Fall includes September–November; and Winter includes December–February.
[b] The watershed area of BPA-4 is only around 1% of the entire Bonneville region. Hence, the BPA-4 values have limited contribution in the overall Bonneville regional average.

The hydrologic characteristics are similar in BPA-1, BPA-2, and BPA-3, all of which belong to the major Columbia River system. Winter precipitation is higher, mostly in the form of snowfall. During spring and summer, snowmelt occurs and results in higher runoff. Given the higher amount of storage in these three assessment areas, the level of hydropower generation varied by a smaller degree than the natural variability of precipitation and runoff. The hydrologic characteristics of smaller Cascade Mountain projects in BPA-4 are different. Winter precipitation is also higher, but in a much larger quantity and variability. Because the watershed is smaller, the storage is limited; hence, generation in BPA-4 is more precipitation-controlled. Higher runoff occurs in winter instead of summer. The smaller storage also results in higher variability in hydropower generation.

3.2.2 Correlations Between Precipitation, Runoff, and Generation

It is known that annual hydropower generation may fluctuate in a large degree, and it poses a major challenge to both water management and PMA power contracting. This variation is mainly due to hydrologic variability, which is jointly influenced by precipitation, runoff, streamflow, snowmelt timing, soil moisture, groundwater recharge, dam regulation, domestic/industrial water usage, vegetation, and urbanization. Given the complexity of the entire hydrologic system, a statistics-based risk assessment framework is required. However, a nationally consistent assessment approach has not been available to quantify the hydrologic sensitivity to hydropower generation. To understand how the major hydrologic variables (i.e., precipitation and runoff) affect hydropower generation, a comparison was performed based on the annual time series of precipitation, runoff, and federal hydropower generation. The predictive regression models with uncertainty bounds are constructed following the analysis.

Generally speaking, a positively correlated linear pattern was observed between precipitation-generation and runoff-generation. The scatter plots are illustrated in Figure 3-2 for precipitation-generation and in Figure 3-3 for runoff-generation. A linear fitting was performed and illustrated for each area, along with the corresponding 95% regression confidence interval (CI). To assist interpretation, the correlation

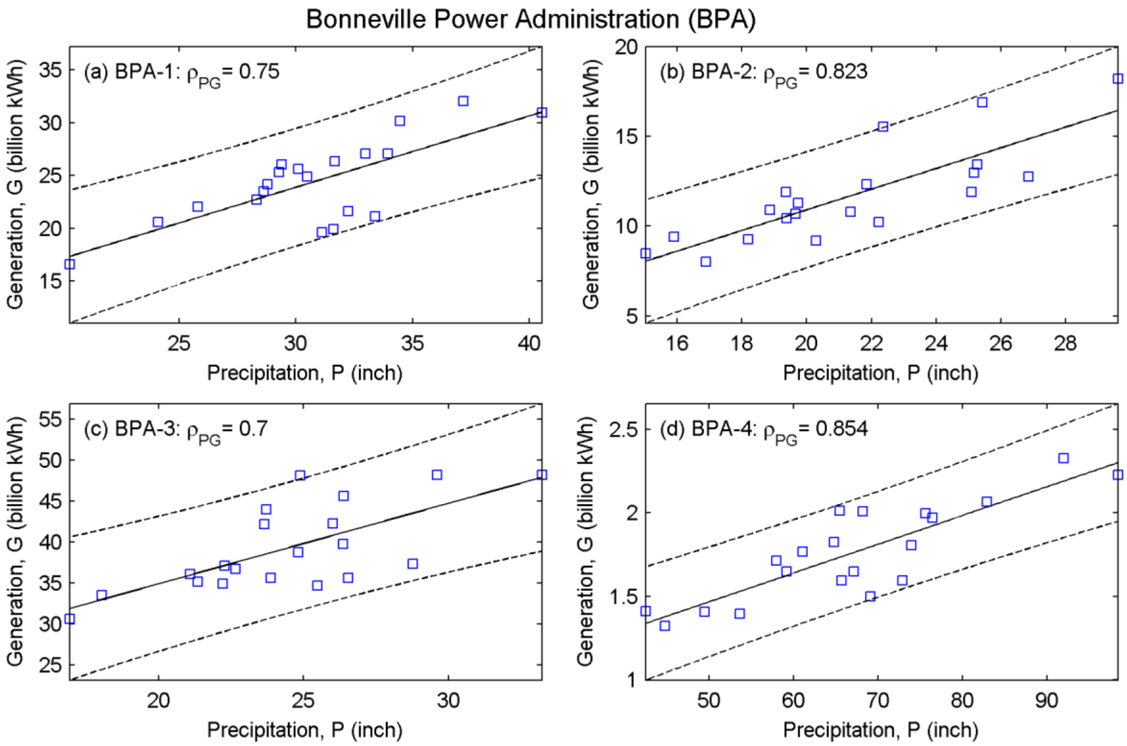

Figure 3-2. Regression between precipitation and generation for Bonneville areas.

coefficients (ρ) are also shown, with 1 indicating fully correlated (strongest linear relationship) and 0 being uncorrelated (weakest linear relationship). Since the power-generating facility and operation scheme changed with time, the regression was performed only on the latest 20 years of data (i.e., water years 1989 to 2008).

In the four Bonneville areas, correlation coefficients between precipitation and generation (ρ_{PG}) range from 0.7 to 0.854, with the highest correlation in the coastal regions (BPA-4) and the lowest in the lower Columbia River Basin (BPA-3). The correlation coefficients between runoff and generation (ρ_{RG}) are much higher, ranging from 0.854 to 0.97, with the highest correlation in BPA-2 and the lowest again in BPA-3. The width of uncertainty bounds can be seen as another indicator showing how strong the relationship is. A narrow uncertainty bound suggests the higher confidence of a prediction model.

For BPA-1, both precipitation-generation and runoff-generation correlations are high. The correlation coefficient ρ_{PG} between precipitation and generation is 0.75, and the 95% CI uncertainty bound is around 8 billion kWh. The runoff-generation relationship is even stronger, with ρ_{RG} being 0.931 and the CI bound around 4 billion kWh. It indicates that while there are many factors that may affect hydropower generation, the dominant variable is runoff, which controls the amount of water available for hydropower generation. The strong relationship supports evaluating hydropower variability from simulated annual runoff directly. Similar results can be found for BPA-2, in which both correlations are even stronger than in BPA-1. The correlation coefficient ρ_{PG} between precipitation-generation is 0.823 with a 3.5 billion kWh CI bound. The relationship between runoff and generation is again stronger, with ρ_{RG} being 0.97 and CI bound around 1.2 billion kWh.

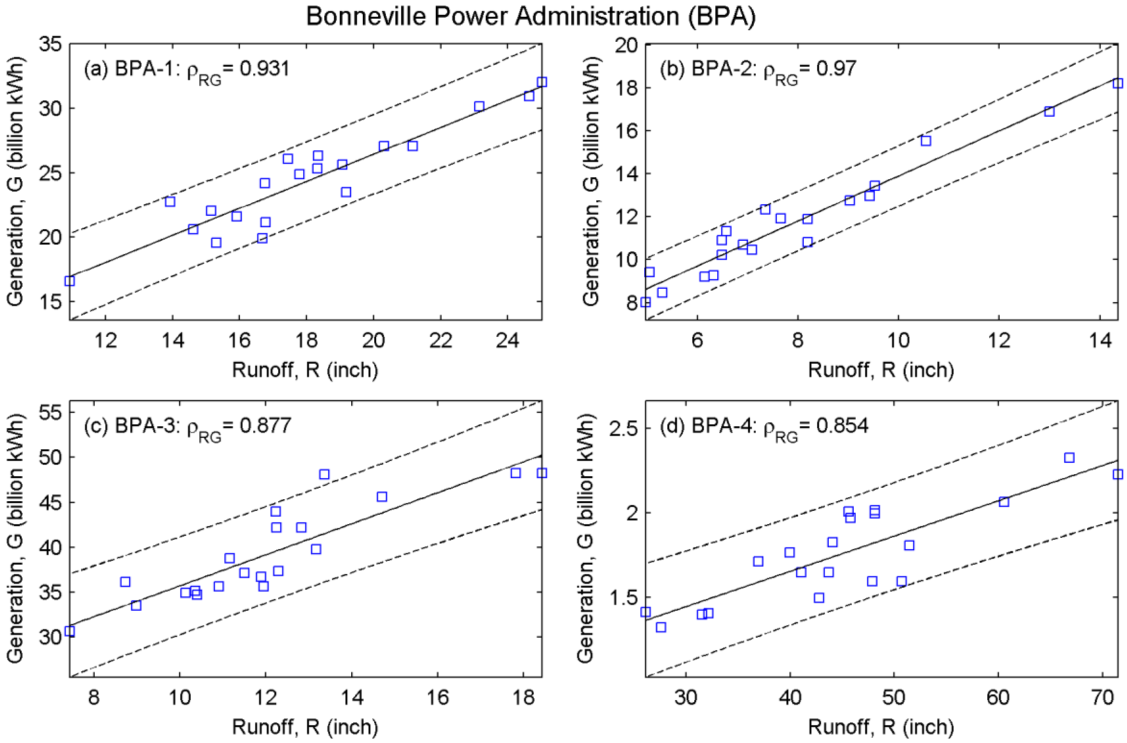

Figure 3-3. Regression between runoff and generation for Bonneville areas.

Whereas BPA-1 and BPA-2 are independent, nonoverlapping watersheds, BPA-3 is the downstream watershed of both BPA-1 and BPA-2. Therefore, the hydrologic output from BPA-1 and BPA-2 will contribute to BPA-3 and should be considered in assessing the hydropower generation of BPA-3. In this consideration, the precipitation and runoff totals for BPA-3 are actually the spatial averages covering the entire watersheds of BPA-1, BPA-2, and BPA-3. A similar approach is performed for some other PMA watersheds. For BPA-3, the runoff-generation correlation (0.877) is larger than precipitation-generation (0.7), and the CI bound is smaller for runoff-generation (6 billion kWh) than for precipitation-generation (9 billion kWh). Given the larger watershed of BPA-3, both relationships are slightly lower than for BPA-1 and BPA-2.

Since BPA-4 is more precipitation driven, the precipitation-generation and runoff-generation correlations are similar. The uncertainty bound is around 0.3 billion kWh. Overall, the correlation between runoff and generation is consistently stronger across all of the Bonneville assessment areas and hence was adopted in Section 3.5 to assess the potential climate impacts on hydropower generation.

3.3 FUTURE CLIMATE PROJECTIONS FOR BONNEVILLE

The four Bonneville assessment areas lie mostly within the PNW portion of the United States (Figure 3-1), which has been the focus of many climate analysis and projection studies over the past few decades. It also is a featured region discussed in several major climate-change–related literature syntheses in the past few years (e.g., Karl et al., 2009; Reclamation, 2011a). Significant warming over the PNW has been observed over the last century; mean annual temperature has risen about 1.6°F (NCDC, 2011) over the region as a whole, with some subregions warming as much as 4.0°F (Karl et al., 2009). Warming rates are significantly greater when calculating trends since about 1970 (true for most regions of the United States), with a regional-average warming of about 1.8°F just for the period 1970–2010 (NCDC, 2011). The century-scale rate of change is smaller by comparison owing to a relatively cool period over the

1950s and 1960s. The main conclusion to be drawn is that since 1970, warming has been especially rapid, on the order of 0.45°F per decade.

Some studies indicate no significant region-wide trends in annual precipitation for the PNW over the long term (e.g., Regonda et al., 2005); however, the observed warming in the latter half of the 20th century has on its own resulted in hydrological changes, including significant decreases in the fraction of precipitation received in the form of snow, reduced snow water equivalent, and earlier snowmelt runoff and peak spring streamflows (Hamlet et al., 2010a; Adam et al., 2009; Mote, 2006).

3.3.1 9505 Assessment Climate Projections

In this section, projections of future Bonneville region climate change are discussed first, using the assessment methods described in Section 2, because they provide the consistent nationwide analytical approach needed for comparison among regions as required for the 9505 report. Projections based on the 9505 ensemble runs are presented for mean annual, spring, summer, fall, and winter air temperature, precipitation, and runoff for the near-term period (2010–2024) and mid-term period (2025–2039); and comparisons are made to the baseline period (1960–1999). The projections are illustrated in Figure 3-4, showing the minimum, median, and maximum changes derived from the five 9505 ensemble members. For ease of reference, we refer here, generally, to approximate averages of the median changes over all four assessment areas (BPA-1 – BPA-4). The detailed cumulative distributions of observed and simulated temperature, rainfall, and runoff are illustrated in Appendix E for each Bonneville assessment area. The maps of projected runoff are shown in Appendix F for the visualization of spatial variability.

Mean annual temperature for the Bonneville region is projected to increase by about 2.0°F and 3.2°F for the near-term and mid-term periods, respectively, compared with the baseline period (left column of Figure 3-4). The mid-term change is the cumulative change, representing an additional warming of about 1.2°F after the near-term. For BPA-1 – BPA-3, the summer season is projected to warm the most (~4°F for the mid-term); for BPA-4, winter warms the most (~3°F for the mid-term). An interesting aspect of the summertime warming shown in Figure 3-4 for all of the Bonneville areas is that the preponderance of the projected warming takes place in the near-term, with only about 1ºF or less additional warming in the mid-term. This is generally not the case for other seasons over all of the areas; in fact, the nature of winter warming projections for BPA-1 – BPA-3 is opposite to those of summer, with most of the total warming taking place in the mid-term.

Changes in mean annual precipitation over the Bonneville region (middle column in Figure 3-4) are less consistent than the temperature changes. The projected changes in Figure 3-4 are in percentages relative to the 1960–1999 baseline precipitation, with ensemble members producing both small positive and small negative changes in mean annual precipitation. Figure 3-4 does show mainly negative projections of summertime precipitation; median projected changes are uniformly negative.

The strongest change projected in mean runoff over the Bonneville region for either of the future 15 year periods is in the summer season (left column in Figure 3-4). The projected changes in Figure 3-4 are in percentages relative to the 1960–1999 baseline runoff. Ensemble members exhibit both positive and negative mean annual changes, with median values being only slightly negative. Figure 3-4 does show uniformly negative projected changes in summertime runoff for all models for both time periods; even the smallest changes are on the order of 10–20% for the near-term and 20–30% for the mid-term. These projections could possibly relate to trends already observed in snow water equivalent and earlier snowmelt runoff in the region (Hamlet et al., 2010a; Mote, 2006). The Cascade Mountains assessment area (BPA-4) stands out with the largest projected decreases in summertime runoff.

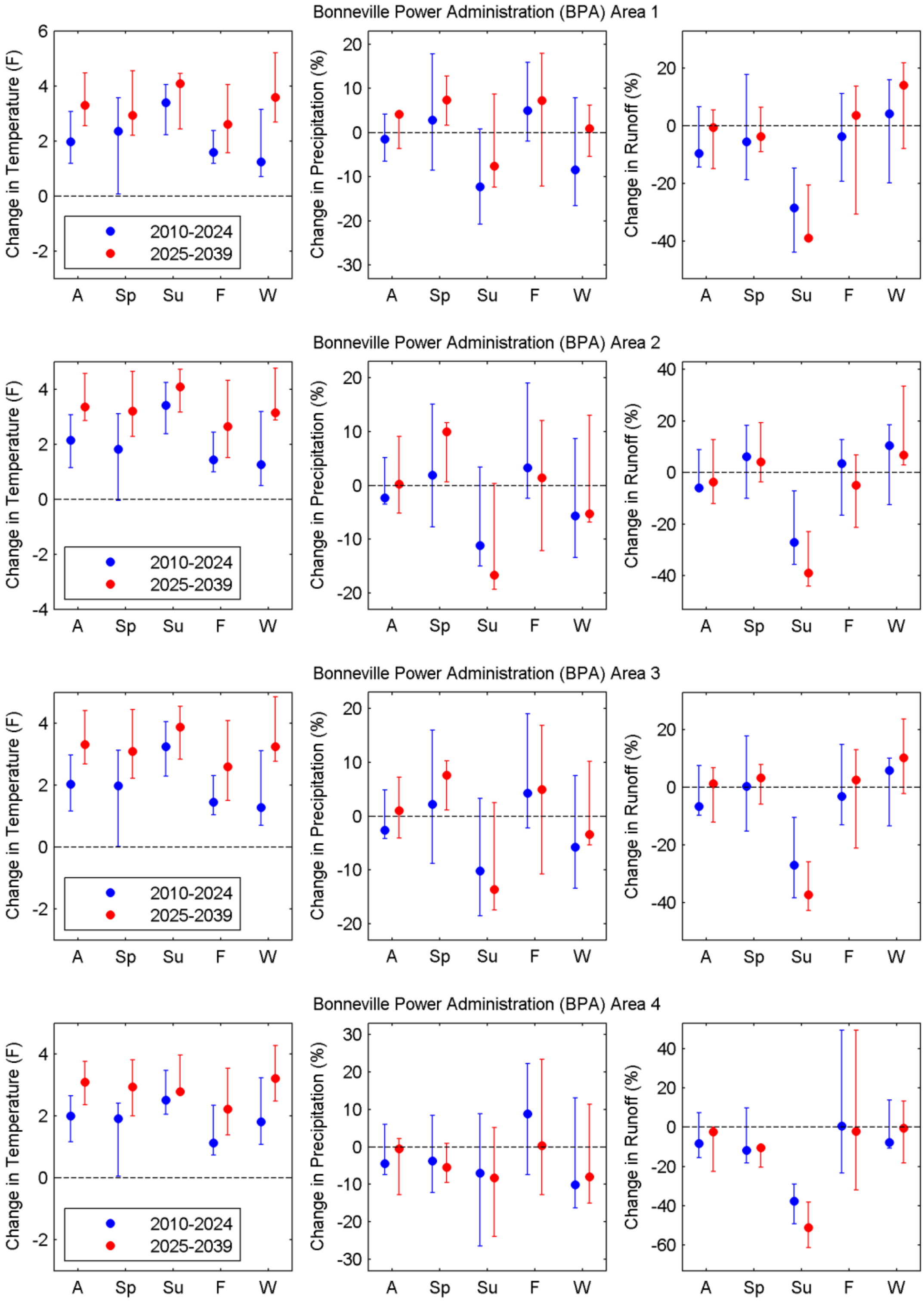

Figure 3-4. Projected change in mean annual and seasonal values of temperature (left column), precipitation (middle column), and runoff (right column) in the Bonneville region, relative to the baseline period of observed climate. The dashed line at zero is based on the mean from 1960 to 1999; circles are the mean of the median ensemble member, and the range plotted around each circle extends from the highest to the lowest ensemble member.

In all of the projected change plots in Figure 3-4, the most important signals are where the trajectory of change (baseline to near-term to mid-term periods) is consistently away from the reference line. Although no test of statistical significance was applied to these change signals, they are nonetheless important results. In the Bonneville region, the more important signals of change are similar in all areas: increases in temperature in all seasons plus decreases in summer precipitation (except BPA-1) and summer runoff.

The 9505 ensemble data can be analyzed in more detail to classify the frequency of water year types and the intensity of extreme low-flow events. Figure 3-5 shows the projected frequency of dry, normal, and wet water years over both future 15 year periods, based upon projected changes in runoff. Water year types are defined by annual runoff values for the baseline period (1960–1999). Annual runoff values less than the lower 20% quantile during the baseline period are designated as dry years, while values greater than the upper 80% quantile are designated as wet years. The blue bars in Figure 3-5 are references to baseline frequency. For example, a change in the dry year frequency from 0.3 to 0.4 in the BPA-1 area (Figure 3-5a) would mean one more dry year per decade.

The near-term period projections show large increases in the frequency of dry years and decreases in normal and wet years, whereas relatively little change is projected in the mid-term period, with the exception of more dry years and fewer wet years for the Cascade Mountains assessment area (BPA-4) and about 30% more dry years in the Snake River assessment area (BPA-2). The counter-intuitive results in BPA-1 – BPA-3 are caused by the joint influence of increasing potential evaporation and precipitation. With increasing temperature, evaporation is enhanced and the amount of simulated runoff is reduced.

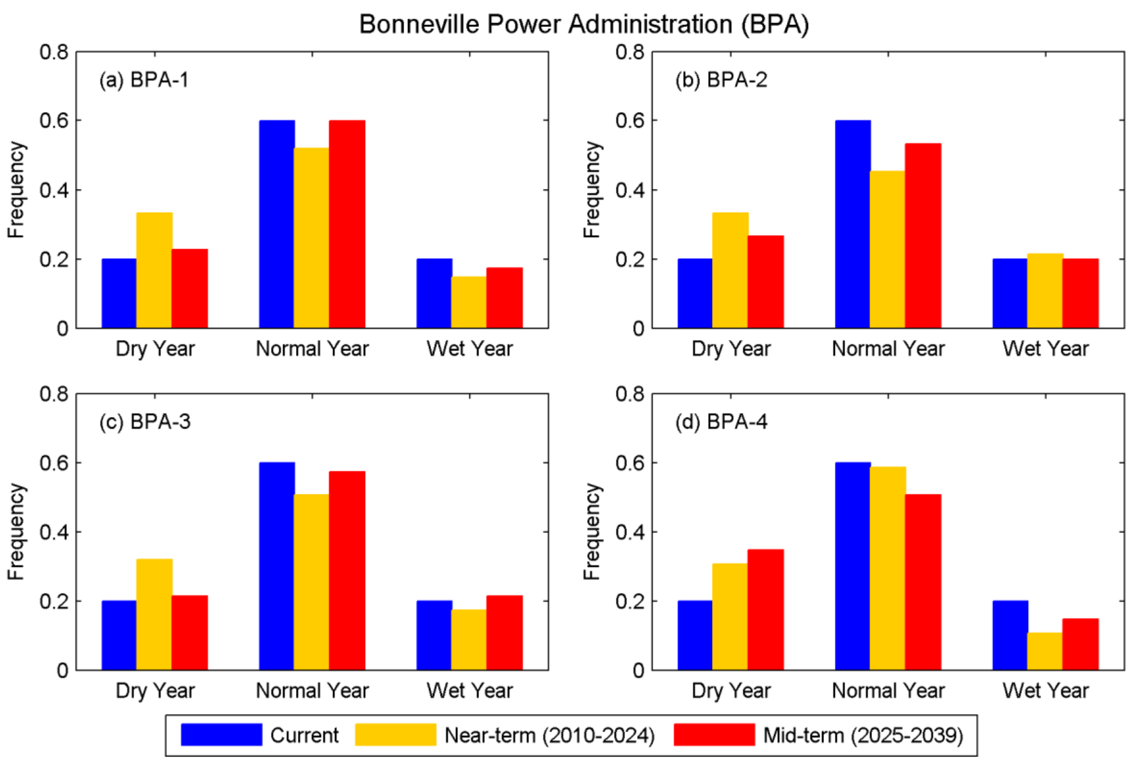

Figure 3-5. Projected frequency of water year type in the Bonneville region, based on the 9505-simulated runoff. Dry, normal, and wet water years are defined by the lower 20%, middle 60%, and upper 20%, respectively, from the 1960–1999 baseline period; these reference values are designated with blue bars to the left of each group.

However, the loss was compensated by the increased precipitation projected in the mid-term. This is a good example of why potential climate change and its effects on hydrology cannot be evaluated by considering only temperature and precipitation changes

Additional extremes-related statistics are shown in Table 3-4, which presents 10 year return level quantiles of seasonal low runoff for both baseline and future projection periods. The 10 year low runoff indicates, statistically, the amount of low flow that may occur every 10 years on average. Strong reductions are projected in both spring and summer, suggesting the potential of more-frequent future droughts. The results are consistent with Figure 3-5. Although short-duration wet extremes are not analyzed in this assessment, a recent study (Kao and Ganguly, 2011) suggested that there could be more intense and frequent precipitation extremes, as observed in meteorological reanalysis datasets and projected by GCMs. It suggests the possibility of more frequent flood events and may increase the difficulty of water management for hydropower operation.

Table 3-4. The 10-year return level quantiles of seasonal low-runoff in the Bonneville region

	10-year low runoff (inches/season), 1960–1999 baseline simulation			
	Spring (Mar–May)	**Summer (Jun–Aug)**	**Fall (Sep–Nov)**	**Winter (Dec–Feb)**
BPA-1	5.05	5.29	1.89	1.56
BPA-2	2.30	1.54	0.76	0.76
BPA-3	3.48	3.01	1.29	1.29
BPA-4	6.58	4.56	7.67	11.26
	10-year low runoff (inches/season), 2010–2024 future projection and percent change from baseline[a]			
	Spring (Mar–May)	**Summer (Jun–Aug)**	**Fall (Sep–Nov)**	**Winter (Dec–Feb)**
BPA-1	4.05 (−20%)	3.61 (−32%)	1.83 (−3%)	1.59 (2%)
BPA-2	2.01 (−13%)	1.22 (−21%)	0.82 (9%)	0.80 (4%)
BPA-3	2.91 (−16%)	2.27 (−25%)	1.38 (7%)	1.39 (8%)
BPA-4	5.06 (−23%)	2.50 (−45%)	8.67 (13%)	10.23 (−9%)
	10-year low runoff (inches/season), 2025–2039 future projection and percent change from baseline[a]			
	Spring (Mar–May)	**Summer (Jun–Aug)**	**Fall (Sep–Nov)**	**Winter (Dec–Feb)**
BPA-1	4.26 (−16%)	3.32 (−37%)	1.78 (−6%)	1.65 (6%)
BPA-2	2.05 (−11%)	1.00 (−35%)	0.71 (−6%)	0.89 (16%)
BPA-3	2.78 (−20%)	1.87 (−38%)	1.31 (2%)	1.37 (7%)
BPA-4	5.22 (−21%)	2.43 (−47%)	7.58 (−1%)	10.47 (−7%)

[a] The percentage indicates the relative change compared with the baseline.

3.3.2 Other Climate Studies of the Bonneville Region

These 9505 Assessment simulations of temperature, precipitation, and runoff for the Bonneville region across 2010–2039 cannot be directly compared with projections from other available studies owing to several factors, such as differences in spatial domain (the Bonneville region does not cover all of the PNW), differences in GHG emissions scenarios in the models, different spans of baseline and projection periods, and the fact that the output has been statistically bias-corrected. Nonetheless, some qualitative statements and comparisons between this assessment and other studies can be made. Mote and Salathé (2010) used a 20-member ensemble of GCMs obtained from the Program for Climate Model Diagnosis and Intercomparison (PCMDI) to examine potential changes in temperature and precipitation over the

PNW region (mainly Washington, Oregon, Idaho, and western Montana). Models were of varying spatial resolution, and the ensemble was run under both the A1B emissions scenario (the 9505 Assessment scenario) and the B1 scenario (weaker GHG gas forcing than A1B but not largely different until the second half of the 21st century). The findings of Mote and Salathe (2010) show projected increases in mean annual temperature of 2.0°F on average by the 2020s and 3.2°F by the 2040s, corresponding closely with the 9505 Assessment projections described above, although the projection periods differ slightly. Their model projections of mean annual precipitation over the PNW show a wide variance over the coming decades but, on average, very little change. Some of the model projections in their ensemble show decreases in summertime precipitation, generally consistent with the 9505 Assessment.

Reclamation (2011b) analyzed model output from the CMIP3 with three emissions scenarios (A1B, B1, and A2) to project changes in temperature, precipitation, runoff, and other variables for about a dozen major western watersheds, including the Columbia (portion of the basin above "Columbia River at the Dalles," equivalent to BPA-1 – BPA-3: Upper Columbia, Snake River, and Mid-Lower Columbia). Their study employed the BCSD technique of Wood et al. (2002) to generate downscaled translations of 112 CMIP3 projections. They noted that these projections are generally not dependent on the particular emission scenario until near the middle of the 21st century. Since the 9505 Assessment uses the A1B scenario (a midrange forcing scenario between B1 and A2) and employs a bias-corrected downscaling approach, it can be viewed as essentially a middle-ground approach with respect to Reclamation (2011b); so, in that sense, it may be reasonable to compare the Reclamation (2011b) and 9505 Assessment projections for the "Columbia" Basin. An important distinction between the results of the 9505 Assessment and Reclamation (2011b), however, is the base climate period to which the projections relate: 9505 Assessment's base period is 1960–1999, which, for temperature, means a cooler reference mean than that of Reclamation's base period of the 1990s. Thus Reclamation's explicit projection of change in temperature for the 2020s (the middle 10 years of their 2010–2039 period) is only +1.4°F cooler (their Table 3), than the 9505 Assessment's projections of +2.0°F for 2010–2024 and +3.2°F for 2025–2039 noted in the previous section. For a better estimate of how well the two assessments' projections of changes in temperature may agree, one must carefully examine the time series shown in Figure 28 of Reclamation (2011b), which shows an increase of about 2.5°F from the 1960–1999 period through the 2020s (close to the middle of the two 9505 Assessment 15 year period projections). Reclamation (2011b) projections of mean annual precipitation and runoff are also incorporated in the SWA 9503 assessment (Reclamation, 2011c), and show very little change through the 2020s (their Figures 17 and 19), consistent with the 9505 Assessment. Reclamation (2011c), like the 9505 Assessment, does project a modest increase in wintertime (December to March) runoff (about 10%; their Table 2) over the region (see BPA-1 – BPA-3 in Figure 3-4).

NARCCAP (Mearns et al., 2009) temperature and precipitation projections can also be generally compared with the 9505 Assessment results. NARCCAP provides results from the CCSM3 (driving GCM of 9505 Assessment) coupled with the Canadian Regional Climate Model (CRCM) and MM5I. An important distinction between NARCCAP and the 9505 Assessment is the GHG scenario used; NARCCAP uses A2, presumably resulting in considerably stronger forcing, especially later in the 21st century. Seasonal projections for 2041–2170 (relative to a 1971–2000 base period) are readily available from the NARCCAP website. The CCSM+CRCM temperature projections for 2041–2070 may be described as essentially extrapolations of the warming rates found for 2010–2039 in the 9505 Assessment, including stronger warming being seen for summer. As for precipitation, the CCSM+CRCM projections for 2041–2070 indicate little change from the baseline period in terms of annual means, but decreases are projected for summertime precipitation (an extension of 9505 Assessment 2010–2039 projections), somewhat offset by increases in autumn precipitation (a season not explicitly part of the 9505 Assessment). The CCSM+MM5I temperature and precipitation projections may be similarly characterized, except that the magnitude of projected warming is considerably less than in CCSM+CRCM.

The Columbia Basin Climate Change Scenarios Project (CBCCSP; Hamlet et al. 2010b) was a collaborative venture between the University of Washington Climate Impacts Group and five regional study partners, funded primarily by the Washington State Department of Ecology via Washington State House Bill 2860. The primary objective of the project was to provide a comprehensive and up-to-date database of simulated hydrologic data incorporating climate change information from the IPCC Fourth Assessment Report to support long-term water resources planning in the PNW Columbia River Basin, and the assessment of climate change impacts on the terrestrial, fluvial, and coastal marine environments.

A total of 77 hydrologic model scenarios (covering 2030–2059) were produced in the study, based on data from ten GCMs, two emissions scenarios (A1B and B1), and three downscaling methods, encompassing 297 streamflow locations. Great emphasis was placed on estimating changes in flow and energy production at monthly time scales. The CBCCSP work helped form the foundation for a subsequent assessment of future climate change over the Bonneville region: the RMJOC (2010; 2011), established as a reviewing body for the Columbia-Snake River Basin activities of Bonneville, USACE, and Reclamation. The RMJOC, through memoranda of agreement between these agencies, drew upon all their expertise to produce an extremely detailed assessment of the Columbia River Basin climate projections. RMJOC (2010) examined the use of downscaled, bias-corrected CMIP3 projections, as in Reclamation (2011b); but, for a variety of reasons detailed in their report, they decided to emphasize projections from the CBCCSP (described earlier), which they described as representing a breadth of available climate projection information over the PNW, downscaled in a consistent fashion. The RMJOC work used 1970–1999 as the base climate reference period over the region and incorporated both low-emissions (B1) and medium-emissions (A1B) scenarios as a basis for the many different types of models/scenarios described in their report, which included results of nine different GCMs in the development of 18 future climate change projections. These projected climate change scenarios were specifically selected to encompass the range of future temperature and precipitation projections. This range was described in terms of four quadrants on a temperature/precipitation plot: warmer/drier (Q.1), warmer/wetter (Q.2), less warm/drier (Q.3), and less warm/wetter (Q.4). The RMJOC selection process chose one scenario from each of the four quadrants and two scenarios close to the center (less change). In comparison, four of the five 9505 Assessment scenarios lie in RMJOC's Q.1.

RMJOC (2010) runoff projections for 2010–2039 differ somewhat from those of the 9505 Assessment. While changes in mean annual runoff are modest for both, at less than +10% (see RMJOC Figure 70 and Figure 3-4), Figure 79 of RMJOC (2010) shows increases in winter to early-spring runoff ranging from about 20 to >50% depending on the scenario; summertime runoff is projected to change relatively little (from 0 to −10%, depending on the scenario). This contrasts with the 9505 Assessment, which generally projects significant decreases in summertime but little change in winter and spring runoff (Figure 3-4).

It is important to note, however, that the Q.1 scenarios RMJOC selected matched up very well with the 9505 Assessment scenarios in Q.1. This gives some confidence in the consistency of the two reports but also highlights the differences in comparing the 9505 Assessment with a study having a broader-range dataset that includes more scenarios. The average summer runoff reductions of the RMJOC study ranged from about 11 to 17% compared with the 25 to 40% reduction in the 9505 Assessment. The dry scenarios (Q.1) in the RMJOC report ranged from 19 to 33% compared with 9505 Assessment projections of 25 to 40%. If the 9505 Assessment baseline 40 year dataset were adjusted to the 70 year RMJOC dataset, the 9505 Assessment values would be approximately 21 to 36%, a very close match to the RMJOC scenarios.

3.4 EFFECTS ON HYDROPOWER GENERATION IN THE BONNEVILLE REGION

3.4.1 Projection of Hydropower Generation

By combining the annual runoff-generation relationship (Figure 3-3) for each assessment area with the projection of future runoff (Figure 3-4), annual hydropower generation can be estimated, as illustrated in Figure 3-6. The average simulated generation during the baseline period is computed for each of the Bonneville assessment areas, along with their corresponding projected change in the two future periods. Similar to the style in Figure 3-4, the minimum, median, and maximum of the 9505 ensemble are shown. To avoid bias embedded in the VIC modeling, the bias correction technique is applied to the simulated annual runoff using the USGS WaterWatch observed runoff. In Figure 3-6, the dashed line for baseline reference is the mean of simulated 1960–1999 annual generation across five ensemble members; circles are the 15-year mean for the median ensemble member; and the range plotted around each circle extends from the highest to the lowest ensemble member, as a measure of model uncertainty. The numerical results are presented in tables in Appendix H. The minimum and maximum annual hydropower generation during the simulated baseline period (1960–1999), simulated near-term period (2010–2024), simulated mid-term period (2025–2039), and observed recent 20-year period (1989–2008) are also summarized in Appendix H. Detailed cumulative distributions of observed and simulated annual generation are illustrated in Appendix I for each Bonneville assessment area.

According to the median 9505 ensemble, a slightly decreasing trend of annual hydropower generation is projected in the Bonneville region. The minimum and maximum 15-year ensemble mean ranges from decreasing to increasing, suggesting a large uncertainty bound. Although the projected change will add to the historic variability, it is mostly on a smaller scale in the Bonneville region. Therefore, the climate impact on Bonneville hydropower generation may not be significant within the assessment period. Although there could be more dry years, as suggested by simulation (Figure 3-5), the range of annual generation should be similar to what Bonneville has encountered in the past 20 years (see detailed data in Appendix H).

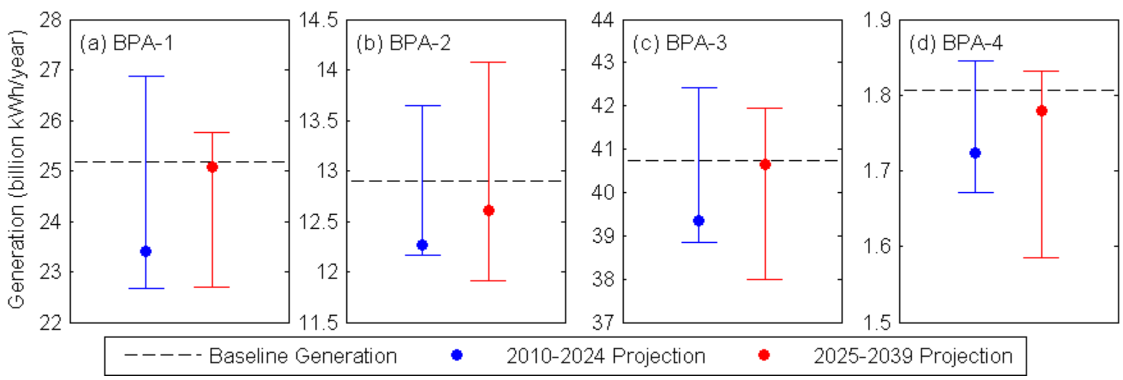

Figure 3-6. Projected annual hydropower generation in the Bonneville region, based on observed correlations with runoff. Dashed line for baseline reference is the mean of simulated 1960–1999 annual generation across five ensemble members; circles are the 15-year mean for the median ensemble member; and the range plotted around each circle extends from the highest to the lowest ensemble member, as a measure of model uncertainty.

3.4.2 Indirect Effects

As used in this report, “indirect effects” refers to climate-related changes to federal hydropower operations that are not included in our 9505 Assessment modeling approach and that can be expected to occur in addition to changes in precipitation and runoff. For example, some changes in air temperature are addressed in the 9505 Assessment models; but air temperature changes will also affect energy demands and usage patterns, which may trigger changes in hydropower generation that are important in balancing power systems. Such an effect is highlighted early in the most recent NPPCC Briefing Book (NPPCC, 2010) and explained in the CCSP (US Climate Change Science Program) SAP 4.5 report on climate impacts on the energy sector (CCSP, 2007).

The increases in temperature projected for the Bonneville region would, taken alone, be expected to increase total and peak electricity demand in the warm season because of increased residential cooling needs. Hamlet et al. (2010a) find that adding in the population growth and air-conditioning penetration expected in Washington State will increase residential cooling energy demand in that region by 165–201% for the 2020s. In absolute terms, this approximate doubling is for a relatively low 1% of total electricity demand related to residential cooling. Nonetheless, Hamlet et al. (2010a) maintain that changes in warm season energy demand will, over time, present a challenge owing to projected decreases in warm-season runoff and attendant decreases in hydropower generation over the Columbia Basin.

Climate warming may also result in increased evaporation from reservoir surfaces, resulting in less water available for hydropower (CCSP, 2007). This effect is hard to confidently predict, however, as evaporation is not determined solely by water and air temperatures; other climate variables such as relative humidity, solar radiation, and cloudiness play important roles. At any rate, reservoirs with the largest surface areas are those potentially most sensitive to this effect.

Other likely indirect effects on hydropower include temperature-induced changes in water quality and aquatic habitat condition (Meyer et al., 1999). Freshwater salmon habitat is of obvious importance in the Bonneville region, and several recent studies (e.g., Mantua et al., 2010 and Battin et al. 2007) point to a host of projections of negative warming-induced effects, including longer high-water-temperature periods in summer that result in thermal stress and migration barriers to salmon, possible increased algae growth resulting in eutrophic conditions in reservoirs, and longer periods of low summertime streamflow. Hamlet et al. (2010a) present a simulated regulated summertime streamflow analysis for the ecologically important Hanford Reach of the Columbia River in August. While summertime indirect effects are likely to dominate in the future, Mantau et al. (2010) also point out that predicted increases in the intensity and frequency of winter flooding in Washington’s transient runoff basins will negatively impact the egg-to-fry survival rates for various salmon species as a result of increased streambed scour. All of these types of effects may, depending on location and severity, require changes in hydropower project operation that reduce power production (CCSP, 2007).

Another indirect effect brought about by increasing warm-season temperatures may include the resultant increasing electricity demand and its effect on GHG mitigation activities, that is, if renewable energy sources such as hydropower become less reliable because of decreased warm-season runoff. Most states in the Bonneville region have specific renewable portfolio standards (e.g., Oregon’s target for major utilities is 25% renewable electricity by 2025 [DSIRE, 2011]). Less hydropower generation in the warm season may affect future development of other renewable capacity (e.g., solar and wind) and/or result in utilities purchasing more electricity generated by renewable sources from other states.

3.4.3 Implications to Federal Power in Bonneville’s Region

The 9505 Assessment is based on input and output variables consistent with other Northwest regional climate change studies. It also provides complementary assumptions that have not been used in previous studies reviewed by Bonneville. Noteworthy in the 9505 Assessment are the selections of

- a single GCM
- the A1B emissions scenario (moderate CO_2 emissions future)

- dynamic downscaling technique (as opposed to the statistical techniques)
- five scenarios chosen
- the future time period bands considered (2010–2024 and 2025–2039)

It is worth noting that four of the five scenarios selected were based on warmer/drier projections than the mean temperature/precipitation projections offered by various GCM outputs. Accordingly, one might expect that the 9505 Assessment would lean toward a slight overall reduction in runoff and generation projections.

The general findings of the 9505 Assessment are consistent with other climate change reports reviewed by Bonneville, including its own internal studies. The primary output variables are temperature and precipitation projections plus the seasonality impacts on runoff timing in the Columbia River Basin. Bonneville appreciates that the 9505 Assessment considers some seasonal (winter/summer) effects along with the annual report outputs. Two other noteworthy aspects of the 9505 Assessment are useful to Bonneville and not often reported on by others: the breakout of the Cascade Basin–BPA-4 (generally referred to as the "Willamettes" within Bonneville), and the reporting runoff variable, which is of particular value in assessing streamflow, elevation, and generation impacts.

The 9505 Assessment indicates a slight decrease in overall annual generation across the region, based on the correlation of annual projected runoff with generation. The amount varies from 1–2 billion kWh/year each in BPA-1, -2, and -3 (northwest region excluding the Willamettes). Assuming these values are accumulative, the lost generation would amount to 3–6 billion kWh/year or roughly an average annual 350–700 MW. This generation reduction would occur in the near-term. The mid-term is predicted to produce generation at levels similar to those produced in 1990–2010. This near-term loss and later rebound is of interest and has not been reported in prior reports. However, this pattern may also be an artifact of the relatively limited 9505 methods (i.e., small, five-member ensemble; single GCM; single emission scenario; and narrow projection window).

Summer will likely see a significant loss in generation during the near-term period, as the summer runoff is predicted to be approximately 25–30% below historic values (for BPA-1, -2, and -3). The seasonal shift to higher winter flows (precipitation) and lower summer flows is consistent with all other climate change studies reviewed by Bonneville (e.g., Vano et al., 2010a,b).

The forecast reduction in summer runoff for the entire 2010–2039 period is noteworthy. BPA-1, -2, and -3 are predicted to be approximately 25–40% below historic levels. Other studies suggest that streamflow reductions will be more severe in late summer than early summer. The Cascade Mountain area (BPA-4) breakout shows an even more severe 40–50% summer runoff reduction from historic levels. Although BPA-4 is not a heavy generation producing area, reduced summer flows likely would result in other significant impacts to this area in terms of water quality, domestic water supply, fishery flows, irrigation, and recreation.

The 9505 Assessment also projects changes in the frequency of dry and wet years by assessment area. This output variable, not commonly reported, is of interest to Bonneville. For the near-term period, in particular, projected increases in the frequency of dry years for the four basins range from 50–65%. It would be useful to gain more understanding of this variable and how it was derived.

Although the summer runoff reductions and annual flow (and resulting generation) reductions cited in the 9505 Assessment are consistent with the general trend of climate impact studies of the Northwest, the specific percentage reductions are significantly larger than the results shown in Bonneville's own studies of the Northwest. The joint regional study that focused on the Northwest used regionally generated climate forecasting and was heavily peer-reviewed.

The primary risks to Bonneville operations and contract practices identified in the 9505 Assessment are as follows:

- Slight decreases in annual generation in the near-term period (2010-2024) projection and in the summer period in particular
- Increased stress to salmon as a result of rising temperatures and changing streamflow
- Increased risk to Cascade Basin projects' ability to maintain summer water quality and minimum flow objectives
- Expectation that energy demand and use will increase as a result of higher air temperatures
- Long-term increase in streamflow volatility resulting in reduced surplus sales, changes in seasonal pricing, and eventual rate increases for customers

The primary climate change risks for Bonneville contracting practices relate to electricity rates charged to federal power customers. For power sales to requirements customers and associated contracts, over the next 5 years, the risks are minimal. In December 2008, Bonneville and its requirements customers signed long-term power contracts with delivery to begin in 2011. These contracts are take-or-pay contracts for prescribed amounts of power. These contracts anticipated potential ongoing changes to the amount and timing of power from the FCRPS, whether these changes are due to climate change, fish and wildlife measures, or any other reason. Under the contracts, the amount customers pay for power may be affected by changes in the output capability of the FCRPS. Whether customer rates might be affected by streamflow changes as a result of climate change over time is a question that deserves some attention.

4. THE WESTERN REGION

This section describes SWA Section 9505 Assessment results for the Western region and the federal hydropower projects located there. The section is organized into four subsections, the first of which explains how the region was subdivided into areas of analysis. The first subsection also presents information on the region's federal hydropower system, power marketing by Western, and major water management issues within the region. The second subsection describes existing hydrology and generation patterns in the region under the current climate (i.e., the baseline for comparison to climate change projections). The third contains results of the climate change projection done for this Section's 9505 Assessment, along with a literature review comparison with climate studies by others. The fourth subsection focuses on potential changes to federal hydropower generation under the projected future climate and possible adaptation options in response to the effects of climate change.

4.1 REGIONAL CHARACTERISTICS

The Western region is geographically the largest of the four PMAs, covering parts of 15 states from California to the Great Plains and from the Mexican to the Canadian borders (Figure 4-1). There are 55 federal hydropower projects in the Western region with a total installed capacity of 10,158 MW and average annual generation of approximately 29.7 billion kWh (Table 4-1 and Appendix B). Therefore, Western has more projects than Bonneville, spread across a much larger service area, but it ranks second to Bonneville in capacity and generation. Both USACE and Reclamation own and operate hydropower projects in this region.

In the 9505 Assessment, the Western region is subdivided into six areas:

- Western Area 1 (WAPA-1): the upper Missouri River and tributaries upstream of the USACE's Gavins Point project
- Western Area 2 (WAPA-2): comprising smaller watersheds in the upper parts of the North Platte, South Platte, Bighorn, upper Arkansas, and upper Colorado Rivers
- Western Area 3 (WAPA-3): the upper Colorado and upper Rio Grande River Basin
- Western Area 4 (WAPA-4): the lower Colorado River Basin, including Reclamation's Hoover, Davis, and Parker Dams
- Western Area 5 (WAPA-5): the lower Rio Grande River, including two small projects operated by IBWC
- Western Area 6 (WAPA-6): the Central Valley of California (Trinity, Sacramento, American, Stanislaus, and San Joaquin river systems) and Truckee and lower Carson River systems

4.1.1 Areas of Analysis

The six different areas of analysis for the Western region are needed to represent the distinctly different hydroclimatic zones in which federal hydropower projects are located. The federal power that comes from the federal projects is marketed in different power systems, corresponding to these assessment areas. The first assessment area (WAPA-1) is defined by the upper Missouri River in Montana, Wyoming, North Dakota, South Dakota, and a small part of Canada. The total drainage area of WAPA-1 covers almost 280,000 mile^2, 4% of which is north of the US–Canada border. This is the largest of the 9505 Assessment areas and corresponds to the eastern division of the Pick-Sloan Missouri River system of multi-purpose water projects. The topography is high plains and mountains with a median elevation of 3,091 ft amsl and maximum elevation of 12,907 ft amsl in the Rocky Mountains of western Montana. Land cover is primarily grassland (76%), plus cropland (14%) and evergreen broadleaf forest (6%).

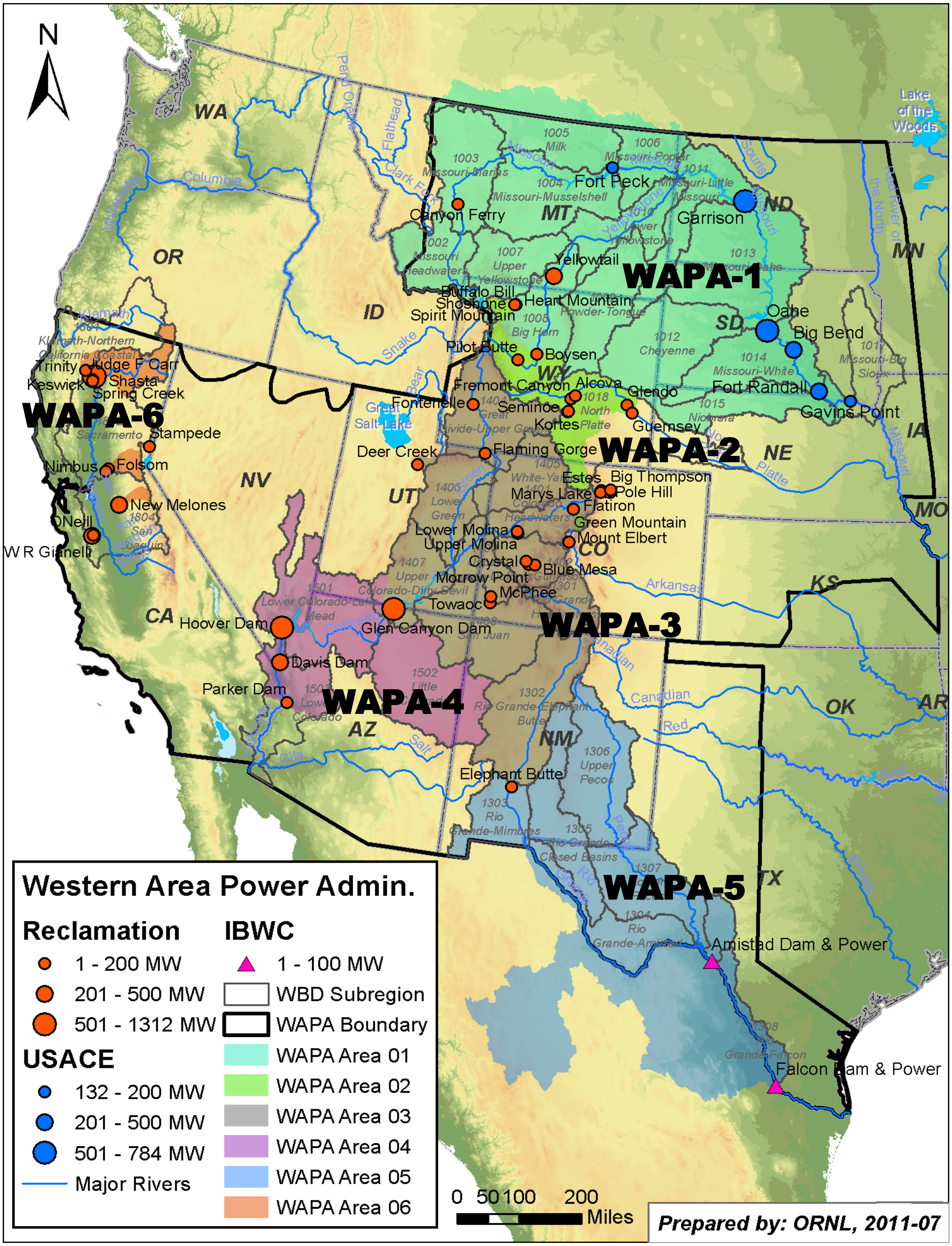

Figure 4-1. Map of the federal hydropower projects and analysis areas in the Western region.

Table 4-1. Hydropower distribution among the areas of analysis in the Western region

Area	Major watersheds	Number of plants				Total installed capacity[a] (MW)	Average annual generation[b] (million kWh/year)
		USACE	Reclamation	IBWC	Total		
WAPA-1	Upper Missouri	6	2	0	8	2830	10505
WAPA-2	Platte-Yellowstone[c]	0	19	0	19	704	1553
WAPA-3	Upper Colorado	0	12	0	12	1820	6099
WAPA-4	Lower Colorado	0	3	0	3	2454	6284
WAPA-5	Rio Grande	0	0	2	2	98	219
WAPA-6	California Central Valley	0	11	0	11	2253	5049
Total		6	47	2	55	10158	29709

[a] EIA 2008 total nameplate capacity. Includes both conventional hydro and pumped storage.
[b] EIA and Reclamation average annual generation from October 1970 to September 2008 (fiscal year). Conventional hydro only.
[c] Two of the four Yellowtail plant units are marketed in WAPA-2; but, for the purposes of this analysis, the entire Yellowtail plant is included in WAPA-1.

The second assessment area (WAPA-2) is made up of smaller watersheds in the upper parts of the North Platte, South Platte, Bighorn, upper Arkansas, and upper Colorado Rivers and corresponds to the Loveland Area Projects (LAP), which includes the Western Division of the Pick-Sloan Missouri River Program and the Fryingpan-Arkansas Project. Total drainage area is 68,843 mile^2. The hydropower projects here are smaller, multi-purpose Reclamation projects with primary purposes of water supply, not power. The topography is mountainous with a median elevation of 6,880 ft amsl and maximum of 14,035 ft amsl. Land cover is grassland (76%), evergreen forest (14%), open shrubland (2%), and cropland (2%).

The third assessment area (WAPA-3) consists mostly of the upper Colorado River Basin west of the continental divide downstream to Reclamation’s Glen Canyon Dam. This area covers approximately 147,000 mile^2. The hydropower projects here are all owned and operated by Reclamation, but they range widely in size. Topography also varies widely from the mountains in Colorado and Utah to arid plains in New Mexico. Median and maximum elevations are 6,880 and 14,003 ft amsl, respectively. Land cover is a mix of grassland (47%), open shrubland (24%), evergreen forest (11%), and woody savanna (4%).

The fourth Western area (WAPA-4) is the lower Colorado River Basin downstream of Glen Canyon Dam. The drainage area is 182,000 mile^2, including the upper Colorado above Glen Canyon. Topography is diverse, ranging from the western slope of the Rocky Mountains down to the deserts of Arizona and Nevada. Median elevation is 5,561 ft amsl, and maximum is over 14, 000 ft amsl. Land cover is mostly open shrubland (69%), with minor amounts of grassland (14%), closed shrubland (10%), and woody savanna (3%).

The fifth area in the Western region (WAPA-5) is the Rio Grande River along the Texas–Mexico border, including the Falcon-Amistad IBWC projects. The drainage area contributing water to these two IBWC projects is over 200,000 mile^2, including the headwaters of the Rio Grande in New Mexico and 71,000 mile^2 in Mexico. This is a much more arid area than others considered in the 9505 Assessment.

Median and maximum elevations are 4,035 and 13,776 ft amsl, respectively, still relatively high except for the immediate area of the two hydropower projects. Most of the land cover is open shrubland (56%), with a mix of grassland (28%), closed shrubland (9%), and woody savanna (4%).

The last of the six Western areas (WAPA-6) is located in the Central Valley and western slope of the Sierra Nevada mountains in California. The range in elevations is from 79 to 13,317 ft amsl, with a median of 4,754 ft amsl. Land cover is mostly evergreen broadleaf forest (54%), plus woody savannas (20%), grassland (14%), and cropland (3%).

4.1.2 Federal Hydropower System

Federal hydropower projects in the Western region are owned and operated by three different agencies: USACE, Reclamation, and the IBWC (Figure 4-1). The six USACE projects are all located in the Upper Missouri River Basin, WAPA-1. The USACE projects are all relatively large in capacity, ranging from the 100 MW Gavins Point project to the 684 MW Oahe project. The two IBWC projects on the Rio Grande are part of multi-purpose water development projects that were constructed primarily for flood control and water conservation; their combined capacity is less than 97.5 MW. Reclamation owns and operates the other 47 hydropower projects in this region. A complete listing of the projects in this region is in Appendix B.

The average age of federal hydropower projects in the Western region is 41 years. The oldest and largest Reclamation hydropower project in Western is Hoover Dam, which began operation in 1936. Hoover Dam's capacity is 2,079 MW and is expected to increase after the modernization of its generating equipment. The smallest and one of the youngest Reclamation hydropower projects in the region is the 1.3 MW McPhee hydropower plant that began operation in 1992. The aging of hydropower infrastructure in the Western region and in other PMA regions is a serious concern for both federal hydropower providers and their customers.

4.1.3 Multi-Purpose Water Management Issues

Water resource development is the lifeblood of the Western region, from California to Minnesota to Texas. Conflicts among competing water uses for a finite and extremely valuable resource is common and continuing. In addition, there are serious concerns over the size and reliability of available water supply; if climate becomes drier in this region in the future, the amount of water resources, already inadequate for growing demands, may become more limited. The national trends and uncertainties associated with water resources at USACE projects have been well described by Dziegielewski and Kiefer (2008). They identified five important issues driving future water resource management:

- population growth and geographical redistribution and associated economic growth
- increasing demand for ecosystem services
- global warming and climate change
- water for energy production
- aging water supply infrastructure

Of these five issues, Dziegielewski and Kiefer (2008) concluded that climate change and the need to provide more water for ecosystem restoration are the most likely to affect future water availability for other uses, such as hydropower. In the western United States, water supply for agricultural, municipal, and industrial uses must also be considered. Rapid population growth—for example in Texas where the state's population may double by 2050—will also push up demand for municipal water supplies in some areas.

The ongoing Colorado River Basin Water Supply and Demand Study being led by Reclamation is the best current example of efforts to better understand future water needs and solutions (Reclamation, 2011d). This study is examining how water supply demands can be met in the future with finite water resources. Much of the water supply in the West is provided by out-of-river diversions, which often involve tradeoffs with in-river water uses such as hydropower and the environment.

Three relevant examples of eco-restoration and its impact on water resource management, including hydropower, are ecosystem restoration and adaptive management in the lower Colorado River, associated with operations of Glen Canyon Dam (NRC/CGER, 1999); the Trinity River Restoration Program, established in Public Law 98-541 and DOI (2000); and the Central Valley Project restoration activities.

The Trinity River Restoration Program resulted in the finalization of a Record of Decision in 2004 establishing new in-stream flow requirements downstream of Trinity Dam and Reservoir. These requirements substantially reduced the amount of water and associated hydropower generation that previously was produced when water was diverted from the Trinity River into the Sacramento River system. Central Valley Project restoration activities are included in a number of ongoing activities that include but are not necessarily limited to the Central Valley Project Improvement Act (CVPIA), the Bay Delta Conservation Plan, and the San Joaquin River Settlement Act. CVPIA was enacted in 1992. Coupled with a number of progressively more restrictive biological opinions to meet Endangered Species Act obligations, as well as climatic variability, it has significantly impacted the water and hydropower accomplishments of the project. The state of California recently passed the Delta Reform Act of 2009. If some proposed natural outflow requirements under consideration for the Sacramento–San Joaquin River Bay-Delta estuary are implemented, this Act would result in additional reductions and changes to the timing, duration, and overall reliability of the Central Valley Project's anticipated water and hydropower accomplishments. Finally, the San Joaquin River Settlement Act was enacted with the express purpose of restoring native and anadromous fish populations in the San Joaquin River and its tributary river systems.

The Report to Congress on SWA Section 9503 (Reclamation, 2011c) described the risks and impacts associated with current and future climate change to multiple water uses in major river basins throughout the Western region. This 9505 Assessment will not duplicate those descriptions. However, the issue that is most important to federal hydropower, and is the subject of the 9505 Assessment, is that hydropower is only one of many competing uses and is rarely the highest-priority. Thus hydropower at federal projects is generated more as a byproduct of water management for other, higher-priority uses, such as water supply for irrigation (Reclamation projects) or flood control (USACE projects). When available water is less than is needed for all uses, hydropower often is the loser. These competing-use impacts (e.g., growing demand for municipal water supply from population growth) may have larger impacts than climate change, and they are not included in the assessment methods used in this first 9505 Assessment.

4.1.4 Power Marketing By Western

Western, created by Congress in 1977, markets and transmits hydroelectric power to almost 700 customers from 10 power systems that are owned by different federal water agencies (Western, 2009b):

- Reclamation Power Systems (Boulder Canyon, Central Arizona, Parker-Davis, Salt Lake Integrated Projects [SLIP], LAP, Provo River, Central Valley, Washoe)
- USACE and Reclamation Power System: Pick-Sloan Missouri River Basin Program—Eastern Division
- IBWC Power System: Amistad-Falcon

Western also owns 17,107 miles of high-voltage transmission (Western, 2009b). In FY 2009, 74% of Western's operating revenues came from sales of electric power and the rest from transmission and other operating revenues. Approximately half of Western's customers are municipalities, cooperatives, and public utility districts. These customer categories accounted for 75% of Western's energy sales in 2009. The rest were distributed among the remaining customer types: Native American tribes, federal agencies, irrigation districts, IOUs, and power marketers.

Western's service area is divided into several regions (Colorado River Storage Project, Desert Southwest, Rocky Mountain, Sierra Nevada and Upper Great Plains) and revenues are collected through ten rate-setting systems. Marketing plans are developed on a project-specific basis. Western develops a power marketing plan either when additions to generation capability occur or when existing power sales contracts expire. Boulder Canyon's marketing plan has the nearest expiration date (September 30, 2017), followed by Pick-Sloan Missouri Basin Program—Eastern Division (December 31, 2020). Marketing plans associated with SLIP, LAP, Provo River, and Central Valley/Washoe Project all expire in 2024. The current marketing plan for the Parker-Davis Project will expire in 2028 and the one for Falcon-Amistad in 2033. Marketing plans typically include allocations of firm power to individual customers or describe how the allocations will be assigned and the specific terms and conditions under which the power will be provided. An allocation is an opportunity to contract for an assigned amount of power rather than a right to receive power. Western typically requires potential customers to enter into a contract within 6 months to a year after allocations are determined. Only when the contract is signed does the allocation become a contract commitment (Western, 2009a).

Western offers four basic types of contracts: long-term firm power and other long-term sales, nonfirm energy and short-term sales and purchases, seasonal power sales, and purchase power. In addition, Western provides opportunities to contract to receive ancillary services, transmission, and other miscellaneous power and/or transmission-related products. Long-term firm power is available only for preference customers. Western offers them different amounts of capacity and energy in summer versus winter seasons. Changes to the power commitment in these contracts must be due to changes in hydrology or river operations, and require a public process and 5 year notice (Western, 2009a). In contrast, nonfirm energy service can be interrupted upon telephone notice, at Western's discretion.

In FY 2009, Western sold 36.2 billion kWh, of which 32 billion kWh corresponded to long-term energy sales. The Amistad-Falcon and Provo River projects, as well as the Central Valley and Washoe projects in the Sierra Nevada Region, do not allocate capacity among their customers—they sell only energy.[4] Customers from these projects pay a share, proportional to the amount of energy they receive, of the revenue requirement determined in each year's Power Repayment Study. Table 4-2 summarizes the services and rates offered by each hydropower project (Federal Register, 2010b; Federal Register 2011).

Total contracted rates of delivery (i.e., committed capacity) in the LAP add up to 626 MW in the winter season and 715 MW in the summer season (75 and 86% respectively of total installed capacity in this project). SLIP's contracted rates of delivery equal 77% of total installed capacity during the winter season and 72% during the summer season. Contracted rates of delivery by customers in the Pick-Sloan Eastern Division correspond to 80% of the total installed capacity over the summer months versus 76% during winter months. All of the customers served by the Boulder-Canyon Project purchase power in a contingent basis, whereas all the customers served by the Parker-Davis Project have long-term firm power contracts.

[4] The Sierra Nevada Region Project also sells transmission

Table 4-2. Western rate schedule summary

	Regional office	Capacity charge ($/kW-month)	Energy charge (mills/kWh)
Pick-Sloan Eastern Division	Upper Great Plains	7.65	19.05
Loveland Area Projects	Rocky Mountains	5.43	20.71
Amistad-Falcon	Colorado River Storage Project		Energy only
Provo	Colorado River Storage Project		Energy only
Salt Lake Integrated Projects	Colorado River Storage Project	5.18	12.19
Boulder Canyon	Desert Southwest	1.90	9.86
Parker Davis	Desert Southwest	1.86	4.24
Central Arizona Project	Desert Southwest	Transmission rates only	
Central Valley & Washoe	Sierra Nevada		Energy only

Unlike Bonneville, Western is not responsible for load growth (the cost of obtaining additional power resources is not included in the rates). Several projects (Pick-Sloan Missouri Basin-Eastern Division, LAP, SLIP, Central Valley Project, and Parker Davis) withdraw some power from current customers at the end of a specific contract term and set it aside in a resource pool to market it to new customers. In some projects, there are planned withdrawals at 5 year and 10 year intervals to make additional power available for allocations to new customers (Western, 2009a).

In its Power Repayment Studies, Western uses a variety of criteria to derive its power rates. For instance, the Colorado River Storage Project looks at median hydrological conditions. Other systems, such as Falcon Amistad and Provo River, are "take all, pay all" and do not consider hydrological conditions when setting rates (Federal Register, 2009a; Federal Register, 2010a). Years with surplus sales accelerate repayment, whereas years of drought may cause Western to accrue deficits that are capitalized and repaid at the current interest rate. When Western has to purchase power because of drought conditions, the resulting costs are paid by firm power customers, except when Western has contract arrangements in place to make purchases on a pass-through cost basis. Western also has to purchase power to furnish its obligation of matching energy to load in the four control areas for which it is an operator (Western, 2009a). The costs of these purchases are passed on to the customers that generated the imbalance. Many of Western's projects have experienced rate increases in the last few years associated with the need to buy power to firm up Western's contractual obligations as a result of regional drought conditions and changes to reservoir operations (changes in water use, maintenance schedules and accommodations for endangered species, and recreational fisheries). In SLIP, not only did rates increase but also energy commitments to customers were reduced by 25% in 2004, increasing each year until 2009 to a level 18% below the pre-2004 level; this constitutes a permanent reduction in energy allocation to the customers.

Western has federal and nonfederal liabilities. It faces relatively higher financing costs on its appropriated debt than other PMAs because of an abundance of more recent construction projects with higher interest rates. For instance, about 60% of debt outstanding at the end of FY 1998 for SLIP carries interest rates ranging from 7 to 11%. The Hoover Power Plant Act of 1984 granted Western authority to spend the revenues from Boulder Canyon Project power sales without needing new appropriations. These proceeds are deposited in the Colorado River Dam Fund and are available to Reclamation to pay for O&M expenses and interest costs. SLIP has similar revolving funds (CBO, 1997). Western does not have borrowing authority from the Treasury as Bonneville and TVA do. However, it is using nonfederal financing to finance Hoover Dam refurbishments and using future power sales as collateral. Western has raised $76,500,000 from its customers to supplement federal appropriations in funding O&M and ongoing rehabilitation of transmission facilities required to deliver federal hydropower generation reliably.

4.2 WATER AVAILABILITY AND HYDROPOWER GENERATION

4.2.1 Observed Hydrology and Generation

The 1971–2008 average annual, spring (March, April, and May), summer (June, July, and August), fall (September, October, November), and winter (December, January, and February) temperature, precipitation, runoff and generation are summarized in Table 4-3 for the six Western assessment areas.

Table 4-3. Summary of the 1971-2008 average temperature, precipitation, runoff, and generation for the Western assessment areas

	Temperature (°F)					Precipitation (inches)				
	Annual	Spring[a]	Summer[a]	Fall[a]	Winter[a]	Annual	Spring	Summer	Fall	Winter
WAPA-1	43	43	66	44	21	16.5	5.3	6.0	3.4	1.8
WAPA-2	41	39	61	41	21	16.5	5.8	3.7	3.9	3.1
WAPA-3	45	44	65	46	26	14.9	3.7	3.8	4.1	3.3
WAPA-4	49	47	69	50	30	13.7	3.3	3.3	3.7	3.4
WAPA-5	61	61	76	61	45	15.6	2.6	6.4	4.6	2.0
WAPA-6	49	46	65	50	35	39.3	10.6	1.7	8.3	18.7
WAPA	50	49	69	50	30	15.9	4.1	5.3	3.9	2.6
	Runoff (inches)					**Generation (million kWh)**				
	Annual	**Spring**	**Summer**	**Fall**	**Winter**	**Annual**	**Spring**	**Summer**	**Fall**	**Winter**
WAPA-1	2.2	0.7	0.9	0.3	0.3	10505	2373	3120	2712	2300
WAPA-2	3.8	1.1	1.8	0.5	0.4	1553	384	570	287	312
WAPA-3	2.9	1.0	1.1	0.4	0.4	6099	1444	1831	1369	1455
WAPA-4	2.3	0.8	0.9	0.3	0.3	6284	1905	1863	1264	1252
WAPA-5	0.7	0.2	0.2	0.1	0.2	219	81	59	39	40
WAPA-6	11.7	4.6	2.0	1.4	3.7	5049	1351	1751	955	992
WAPA	2.1	0.7	0.8	0.3	0.3	29709	7533	9190	6635	6351

[a] Spring includes March–May; summer is June–August; fall is September–November; and winter is December–February.

Using drainage area as a weighting factor, the average across the entire Western region was also computed. The mean annual precipitation and runoff of the Western region are 15.9 and 2.1 in., respectively. Western is the driest PMA and has the lowest runoff-to-precipitation ratio (13%). Since there are several large reservoirs such as Big Bend Dam and Reservoir, Lake Powell (impounded by Glen Canyon Dam), and Lake Mead (impounded by Hoover Dam), Western is able to reliably provide the second-highest hydropower generation among the four PMAs. Whereas the Columbia River system can store only about 28% of the average annual runoff, the Missouri River and Colorado River systems are capable of storing 300 and 400%, respectively, of the average annual flow. Also, because of the large area it covers, the hydrologic conditions within Western assessment areas are diverse.

In addition, the cumulative distributions of observed monthly temperature, rainfall, runoff, and generation are illustrated in Appendix D for each of the Western assessment areas. On the graphs in Appendix D, solid black lines represent the distribution curves across the entire year, dashed green lines represent the spring months, dashed red lines the summer months, dashed black lines the fall months, and dotted blue lines the winter months. In WAPA-1, the seasonal variability is significant. Both precipitation and runoff are much higher in summer than in winter, indicating the challenge of flood operation during the summertime. The large WAPA-1 reservoir storage provides flexibility in water management; therefore, the variability of hydropower generation is smaller than the natural variability of precipitation and runoff. WAPA-2 is the upstream watershed of both the Missouri River system (WAPA-1) and Colorado River system (WAPA-3 and 4). WAPA-2 is separated as an individual assessment area mainly because of the power system consideration. The highest precipitation is observed in spring and the highest runoff in summer. The variability of WAPA-2 generation is higher because of the smaller size of its storage. hydrologic characteristics of WAPA-3 and 4 are similar. The seasonality of precipitation is not significant, and it shows similar distributions to annual precipitation. Given that part of winter precipitation is stored as snowpack, summer runoff is much higher in these three assessment areas. The Deer Creek and Elephant Butte projects, although not belonging to the Colorado River system, were included in WAPA-3 for geographical and power system considerations. In computing the regional temperature, precipitation, and runoff for WAPA-4, all upstream watersheds in WAPA-3 are used.

WAPA-5 is the driest assessment area in the 9505 Assessment. The ratio of runoff to precipitation is 3.8%, indicating the strongest evaporation. Most of the precipitation and runoff occur during summertime. The generation is also the least (1%) within all the Western assessment areas. Note that part of the upstream watershed is in WAPA-3, and it is used when computing the regional average of temperature, precipitation, and runoff. WAPA-6, located in California, has the most distinctive hydrologic condition compared with other Western areas. The Stampede project, although not belonging to the Central Valley Project's river system(s), was included in WAPA-6 for geographical considerations. Precipitation and runoff occur mainly during winter. The seasonal variability of precipitation is much greater than runoff variability because of the buffer of the snowpack. Although natural water resources are more abundant in winter, higher hydropower generation occurs during summer, indicating the role of water management in California. Note also that, although it is smaller in watershed size, WAPA-6 can produce a similar order of hydropower to a large area like WAPA-3.

4.2.2 Correlations Between Precipitation, Runoff and Generation.

It is known that annual hydropower generation may fluctuate to a large degree, and this variation poses a challenge to both water management and PMA power contracting. The variation is mainly due to hydrologic variability, which is jointly influenced by precipitation, runoff, streamflow, snowmelt timing, soil moisture, groundwater recharge, dam regulation, domestic/industrial water usage, vegetation, and urbanization. Given the complexity of the entire hydrologic system, a statistics-based relationship between runoff and hydropower generation was used to construct climate impacts. However, a nationally consistent assessment approach has not been available to quantify the hydrologic sensitivity to hydropower generation. To understand how the major hydrologic variables (i.e., precipitation and runoff) affect hydropower generation, a comparison was performed based on the annual time series of precipitation, runoff, and federal hydropower generation. The predictive regression models with uncertainty bounds are constructed following the analysis.

Generally speaking, a positively-correlated linear pattern was observed between both precipitation-generation and runoff-generation. The scatter plots are illustrated in Figure 4-2 for precipitation-generation and Figure 4-3 for runoff-generation. A linear fitting was performed and illustrated for each area, along with the corresponding 95% regression CI. To assist interpretation, the correlation coefficients (ρ) are also shown, with 1 indicating fully correlated (strongest linear relationship) and 0 representing

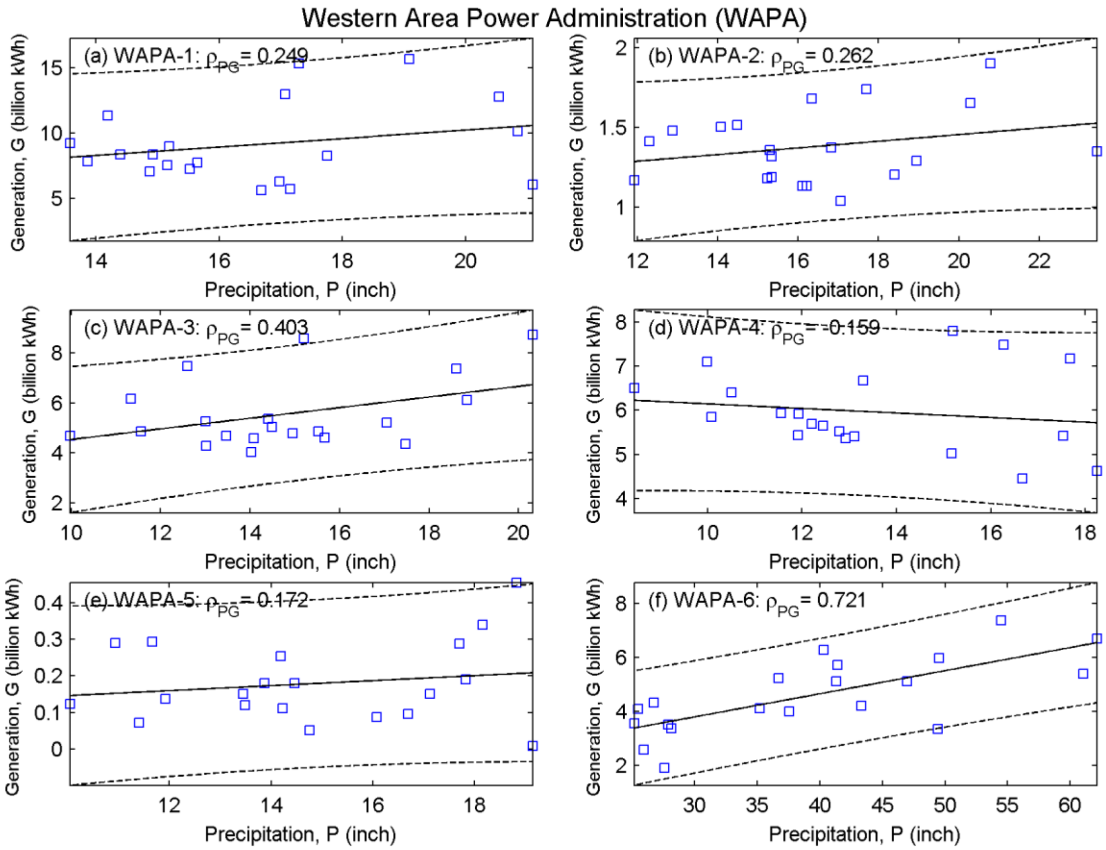

Figure 4-2. Regression between precipitation and generation for Western areas.

uncorrelated (weakest linear relationship). Since water demands and the capability of the power generating facilities and operation schemes change with time, the regression was performed only on the latest 20 years of data (i.e., water years 1989 to 2008).

In the six Western areas, correlation coefficients between precipitation and generation (ρ_{PG}) range from –0.159 to 0.721, with the highest correlation in California (WAPA-6) and lowest in the Lower Colorado River Basin (WAPA-4). The correlation coefficients between runoff and generation (ρ_{RG}) are much higher, ranging from 0.08 to 0.84, with the highest correlation again in WAPA-6 and the lowest again in WAPA-4. The width of the uncertainty bounds can be seen as another indicator showing how strong the relationship is. A narrow uncertainty bound suggests the higher confidence of a prediction model.

For WAPA-1, the correlation between runoff and generation is much greater than between precipitation and generation. The correlation coefficient ρ_{PG} between precipitation and generation is 0.249, and the 95% CI uncertainty bound is around 7 billion kWh. The relationship between runoff and generation is stronger, with ρ_{RG} being 0.766 and CI bound around 5 billion kWh. It indicates that while there are many factors that may affect hydropower generation, the dominant variable is runoff, which controls the amount of water available for hydropower generation. The better performance of runoff-generation is expected for a large watershed like WAPA-1, which is approximately the same size as the entire Bonneville region. The strong relationship supports evaluating hydropower variability from simulated annual runoff directly. Similar correlations can be found for WAPA-2. The correlation coefficient ρ_{PG} between precipitation and generation is 0.262 with a 0.5 billion kWh CI bound. The relationship between runoff and generation is again stronger, with ρ_{RG} being 0.69 and the CI bound around 0.4 billion kWh.

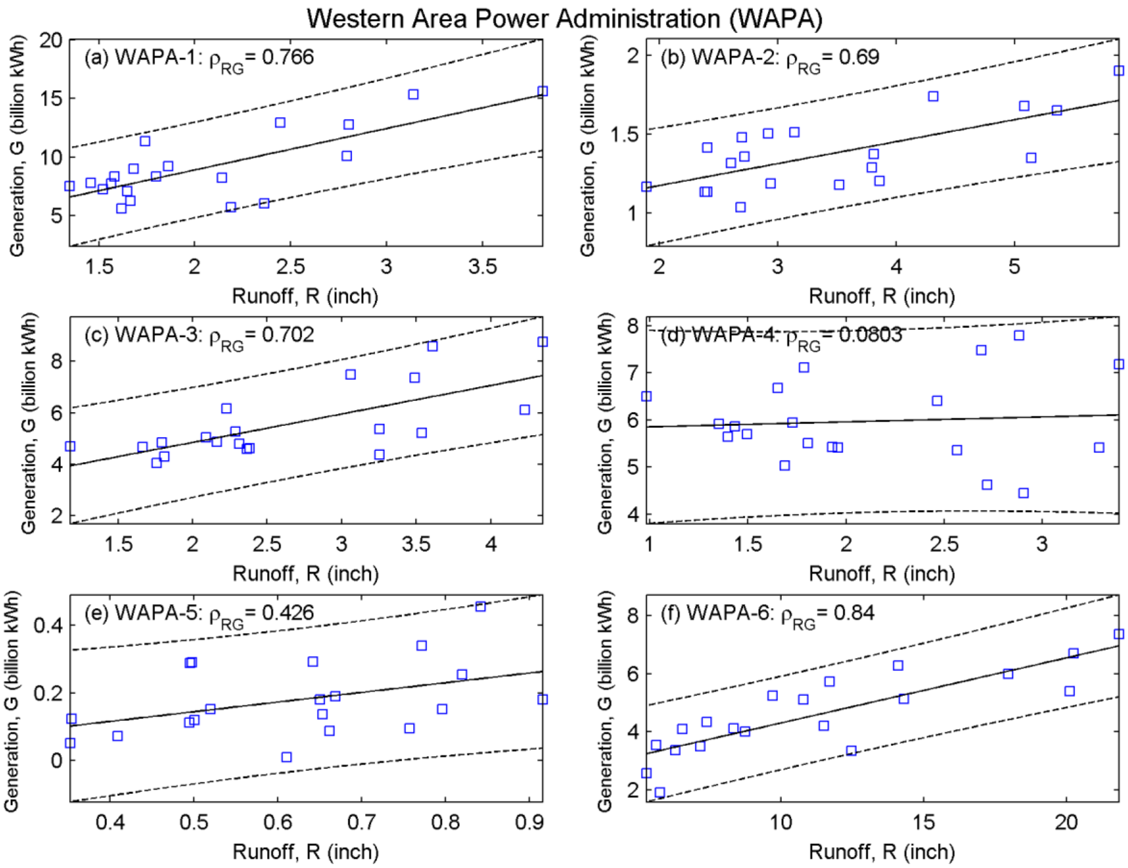

Figure 4-3. Regression between runoff and generation for Western areas.

The correlation between precipitation and generation (0.403) is higher in WAPA-3 but still less than between runoff and generation (0.702). The 95% CI uncertainty bounds are around 3 and 2 billion kWh, respectively. For WAPA-5, the correlation between runoff and generation (0.426) is larger than between precipitation and generation (0.172), but both are smaller than in other assessment areas. Note that part of the watershed is inside Mexico, which has limited meteorological and hydrologic observations. Since other competing water uses (e.g., municipal and irrigation) are of greater importance than hydropower generation in this area, WAPA-5 is less focused in the 9505 Assessment. WAPA-6 watersheds are smaller in size and more precipitation driven. The correlations between precipitation-generation and runoff-generation are close (0.721 versus 0.84), and the uncertainty bound is around 2 billion kWh.

Overall, the correlation between runoff and generation is consistently strong across all Western assessment areas. However, WAPA-4 is a special case among PMA assessment areas. Very low correlations are observed in both precipitation-generation and runoff-generation, and the reason is identified as the multi-year storage inside Hoover Dam. By replacing the annual runoff with the 2 year, 3 year, to 6 year running averages, the correlation was found to be maximized as 0.813 at the 5 year scale. The same approach was applied in other Western assessment areas, and it was found that both WAPA-1 and WAPA-2 are better correlated to the 2 year average runoff, and WAPA-3 is better correlated to the 3 year runoff. Therefore, Figure 4-3 was revised as Figure 4-4, in which the best multi-year runoff is used in the regression equations. All correlations are significantly improved with much smaller CI bounds.

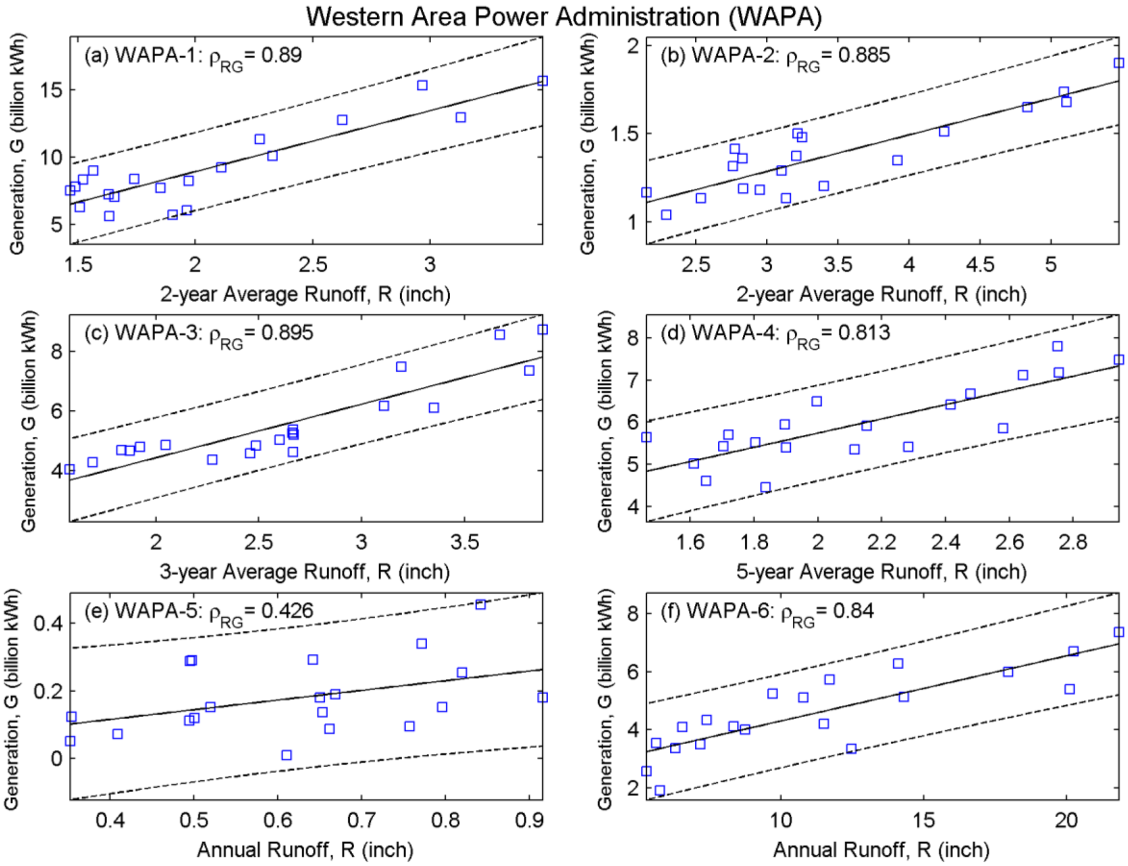

Figure 4-4. Revised regression between runoff and generation for Western areas.

Hence, the equations are adopted in Section 4.4 to assess potential climate impacts on hydropower generation. We note that the multi-year runoff approach was also tested in other PMA assessment areas, but no significant improvement was found.

4.3 FUTURE CLIMATE PROJECTIONS FOR WESTERN

The six Western areas assessed in the 9505 Assessment represent a widespread region that is mostly contiguous along the Rocky Mountains stretching from the US-Canadian border in the north to the US-Mexican border in the south (Figure 4-1). The region also includes the Lower Colorado watershed in the Southwest and several California Central Valley watersheds. Many parts of the Western region have been the focus of climate analysis and projection studies in recent years (e.g., Vicuna et al., 2006; Seager and Vecchi, 2010; Christensen and Lettenmaier, 2007; Qian et al., 2010) in addition to comprising parts of large regions discussed in several major climate-change-related literature synthesis reports in the past few years (e.g., Karl et al., 2009; Reclamation, 2011b). The northern parts of the Western region (including much of Montana, Wyoming, and the Dakotas) comprise most of the National Climatic Data Center's (NCDC's) West-North-Central Region (MT, WY, ND, SD, NE), which has warmed about 1.8°F since 1900 (about 0.18°F per decade) and more than 1.8°F just since 1970 (the century-scale change is no larger than it is because of a relatively cool period over the 1950s and 1960s that muted the trend). The main conclusion to be drawn is that, since about 1970, warming over the northern reaches of the Western region has been especially rapid—on the order of 0.45°F per decade. Temperature changes for the southern portion of the Western region can be approximated using NCDC's Southwest Region (UT, CO, AZ, NM) data (NCDC, 2011), which show century-scale change similar to that in the northern region

(2.0°F) but stronger warming since 1970 of almost 2.5°F (~0.6°F per decade). California Central Valley watershed temperatures, if approximated by examining data for all of California (NCDC, 2011), actually showed a decrease of about 0.9°F from 1900 until about 1970, followed by strong warming of about 2.7°F.

The nature of observed precipitation changes over the large Western region is dependent on the specific assessment area. The Upper Missouri watershed covers much of NCDC's West-North-Central region; it shows only a slight increase in precipitation over the last century, with very dry years in the Dust Bowl of the 1930s and the 1950s and rather large inter-decadal variability since about 1980 (NCDC, 2011). The Upper Colorado (WAPA-3) watershed also shows little evidence of long-term precipitation change. The Lower Colorado (WAPA-4) exhibits a mixed signal with the exception of definitive increases in winter precipitation over most of the last half of the 20th century, extending until the onset of a major drought in the late 1990s (USBR, 2011; Regonda et al., 2005). Long-term California Central Valley watershed (WAPA-6) precipitation change can be estimated using all data for California, which show no significant long-term trend but rather large interannual variability, with precipitation often peaking in El Nino years (NCDC, 2011).

4.3.1 9505 Assessment Climate Projections

As with other regional sections, the 9505 projections of future climate conditions are presented here first, because they provide the consistent assessment approach required for inter-regional comparisons. From the 9505 ensemble runs, projections of mean annual, spring, summer, fall, and winter temperature, precipitation, and runoff change for the near-term (2010–2024) and mid-term period (2025–2039) were produced for each of the six major Western assessment areas. Projections are illustrated in Figure 4-5, showing the minimum, median, and maximum changes derived from the five 9505 ensemble members. For ease of reference, we refer here generally to the median changes over all six watersheds (WAPA-1 – WAPA-6). The detailed cumulative distributions of observed and simulated temperature, rainfall, and runoff are illustrated in Appendix E for each of the Western assessment areas. The maps of projected runoff are shown in Appendix F for the visualization of spatial variability.

Mean annual temperature for the Western region is projected to increase from about 2.2 and 3.4°F for the near-term and mid-term, respectively, relative to the baseline period (left column in Figure 4-5). The mid-term change is the cumulative change, representing an additional warming of about 1.2°F after the near-term period. Summertime warming (> 4°F in the mid-term) is projected to exceed that of all other seasons in the contiguous WAPA-2 through WAPA-5 (as in many parts of the United States), but for WAPA-1 and WAPA-6, winter is projected to warm the most (although only a bit more than summer)—slightly more than 4°F in WAPA-1 and slightly less than 4°F in WAPA-6.

The 9505 methods and results produce a complex picture of changes in precipitation over the Western region (middle column in Figure 4-5), with the range of ensemble members often spanning the baseline reference. The projected changes in Figure 4-5 are in percentages relative to the 1960–1999 baseline precipitation. Mean annual precipitation projections for most areas show relatively little evidence for change over either future 15 year period; however, WAPA-1 (the upper Missouri) does show projections nearing +5% in both periods with respect to the baseline period; and WAPA-5 (the Rio Grande) shows a projection exceeding –5% in the mid-term period. The more important signals of change are in decreasing summer precipitation in all areas except WAPA-1 (upper Missouri), where precipitation is projected to increase.

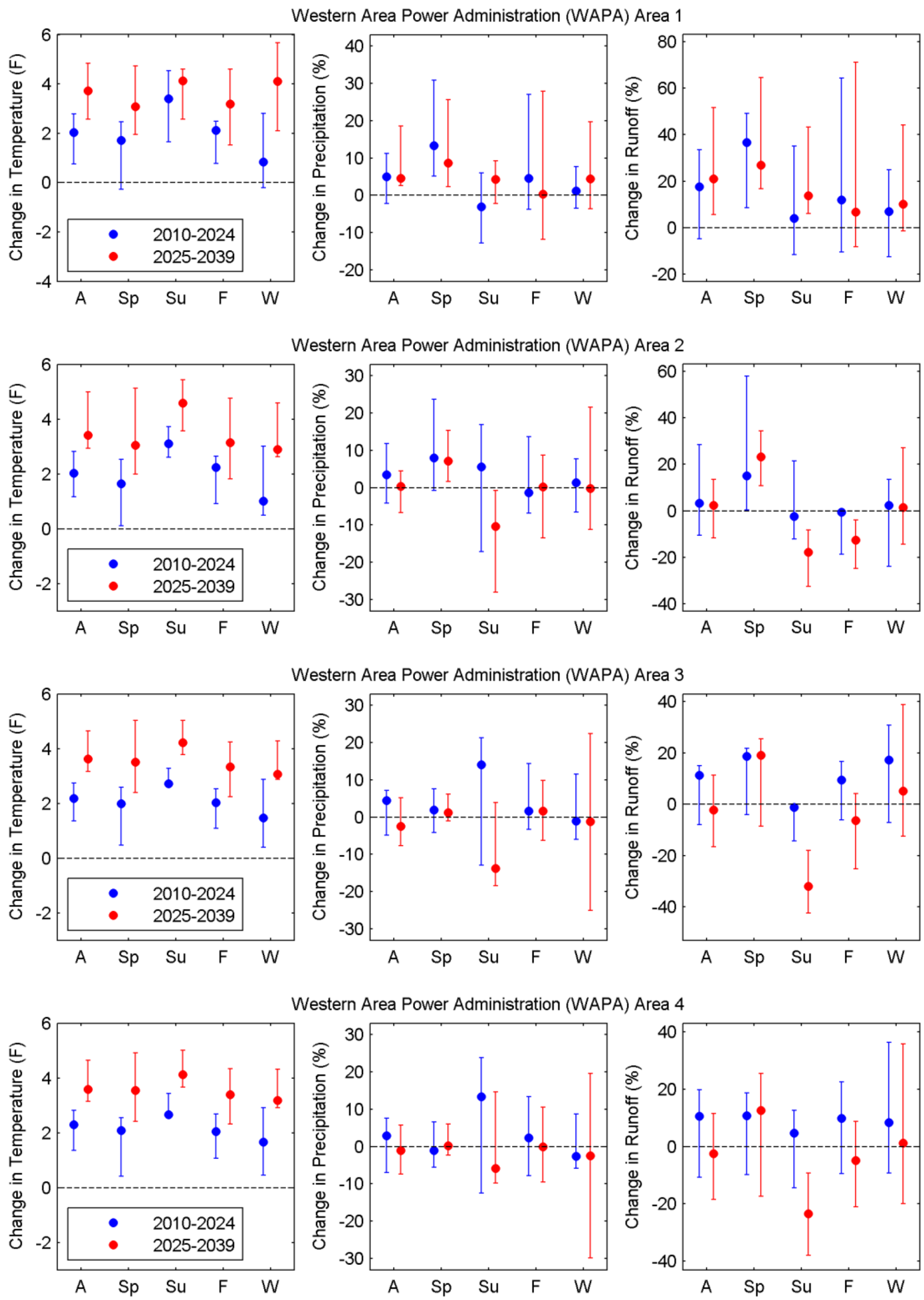

Figure 4-5. Projected change in mean annual and seasonal values of temperature (left column), precipitation (middle column), and runoff (right column) in Western relative to the baseline period of observed climate. The dashed line at zero is based on the mean from 1960 to 1999; circles are the mean of the median ensemble member; and the range plotted around each circle extends from the highest to the lowest ensemble member.

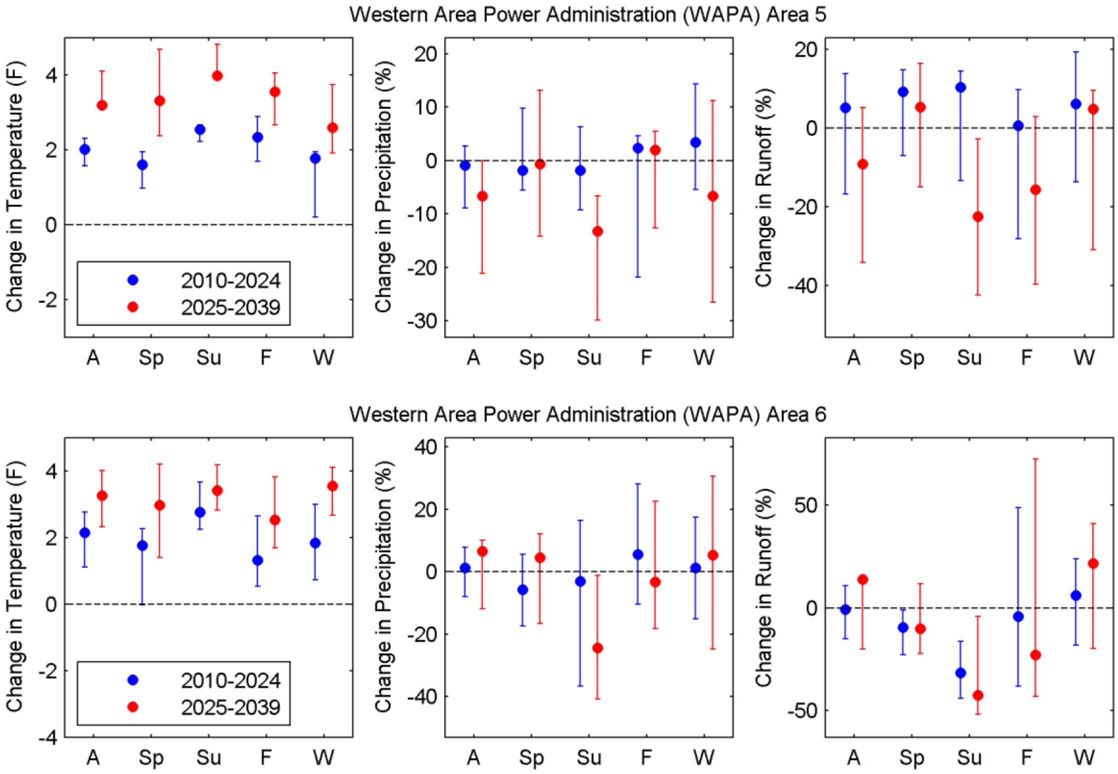

Figure 4-5 (continued). Projected change of mean annual and seasonal values of temperature (left column), precipitation (middle column), and runoff (right column) in Western relative to the baseline period of observed climate.

Changes projected for runoff in the Western region are stronger than for precipitation (right column in Figure 4-5). The Upper Missouri watershed (WAPA-1) is projected to experience increased mean annual runoff, driven largely by increases in the spring; increases are projected to be more modest in the other three seasons. The remaining Western areas, except for the Rio Grande, are not projected to experience much change in mean annual runoff but do show general decreases in summer runoff, especially during the mid-term period (however, WAPA-6 shows decreasing summer runoff for both periods). In the WAPA-5 area (Rio Grande), runoff projections show quite a large spread among the ensembles for the mid-term period (Figure 4-5). The projected decreases in summer and fall runoff are notable.

The projected change in the frequency of water year types is shown in Figure 4-6 over both future 15 year periods, based upon projected changes in runoff. Water year types are defined by annual runoff values for the baseline period. Annual runoff values of less than the lower 20% quantile during the baseline period are designated as dry years, and values greater than the upper 80% quantile are designated as wet years. The Upper Missouri area (WAPA-1) is projected to experience many more wet years, especially in the mid-term period, with the frequency more than doubled compared with the 1960–1999 baseline. Other notable projections include increases in the frequency of wet years exceeding 50% during the near-term period for the Upper and Lower Colorado watersheds (WAPA-3 and WAPA-4); it is interesting that the mid-term period for these same areas shows no projected change in the frequency of wet water years. In addition, the Rio Grande watershed (WAPA-5) is projected to experience large increases in the frequency of dry years and decreases in the frequency of wet years during the mid-term.

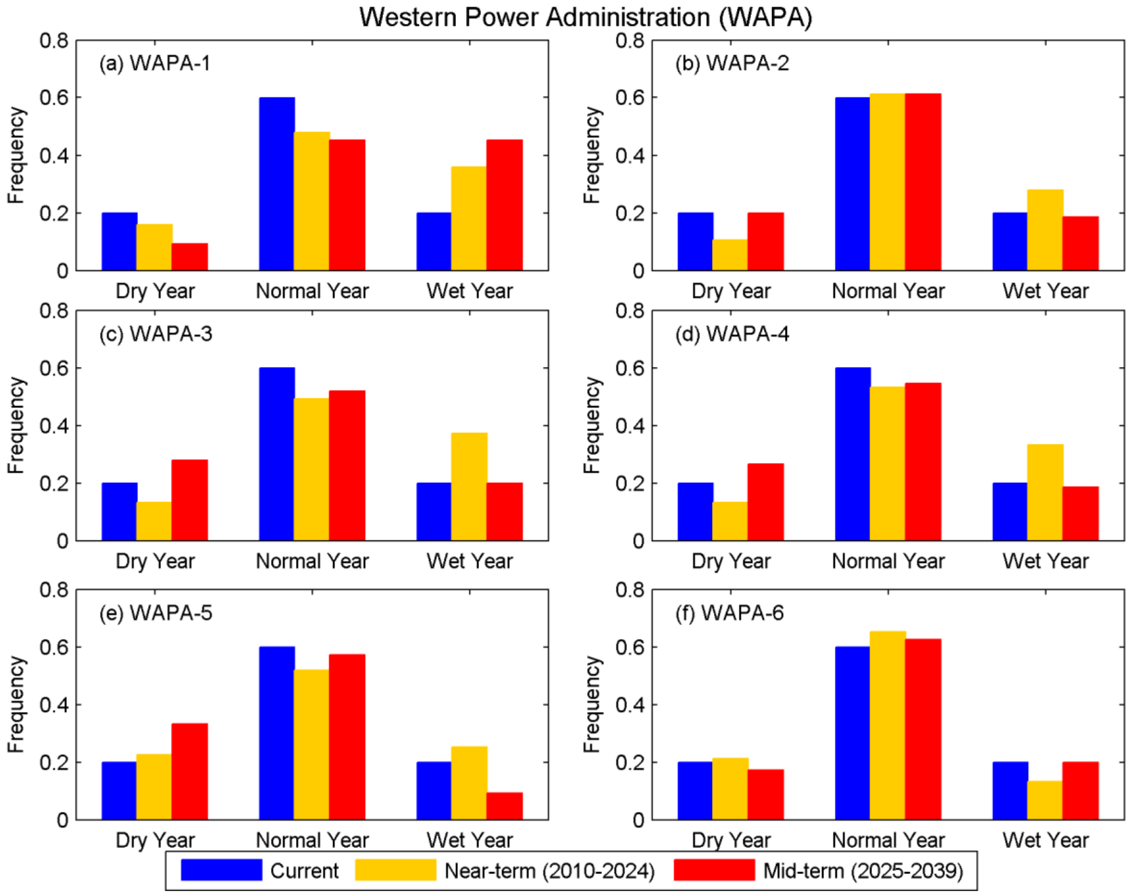

Figure 4-6. Projected frequency of water year type in the Western region, based on the 9505-simulated runoff. Dry, normal, and wet water years are defined by the lower 20%, middle 60%, and upper 20%, respectively, from the 1960-1999 baseline period; the reference values are designated with blue bars to left of each group.

Additional extremes-related statistics are shown in Table 4-4, which presents the 10 year return level quantiles of seasonal low-runoff for both baseline and future projection periods. The 10 year low runoff indicates, statistically, the amount of low flow that may occur every 10 years on average. A wetting trend is again observed in WAPA-1, with large increases in projected winter and spring runoff. Strong reduction of summer runoff is projected in the mid-term for the other five Western areas, suggesting the potential for more droughts in the future. The results are generally consistent with Figure 4-6. Although short-duration wet extremes are not analyzed in this assessment, a recent study (Kao and Ganguly, 2011) suggests there could be more intense and frequent precipitation extremes, as observed in meteorological reanalysis datasets and projected by GCMs. It suggests the possibility of more frequent flood events and may increase the difficulty of water management for hydropower operation.

4.3.2 Other Climate Studies in the Western Region

These 9505 Assessment projections of temperature, precipitation, and runoff for the Western region across 2010–2039 cannot be directly compared with projections from other available studies owing to several factors, such as differences in spatial domain, differences in GHG emissions scenarios in the models, the different spans of baseline and projection periods, and the fact that the output has been statistically bias-corrected. Nonetheless, some qualitative statements and comparisons can be made between this assessment and other studies. Reclamation (2011b) analyzed model output from the CMIP3

Table 4-4. The 10-year return level quantiles of seasonal low-runoff in the Western region

	10-year low runoff (inches/season), 1960–1999 baseline simulation			
	Spring (Mar–May)	**Summer (Jun–Aug)**	**Fall (Sep–Nov)**	**Winter (Dec–Feb)**
WAPA-1	0.51	0.50	0.27	0.51
WAPA-2	0.74	0.98	0.35	0.74
WAPA-3	0.68	0.61	0.26	0.68
WAPA-4	0.54	0.49	0.23	0.54
WAPA-5	0.11	0.13	0.07	0.11
WAPA-6	1.99	1.11	0.88	1.99
	10-year low runoff (inches/season), 2010–2024 future projection and percent change from baseline[a]			
	Spring (Mar–May)	**Summer (Jun–Aug)**	**Fall (Sep–Nov)**	**Winter (Dec–Feb)**
WAPA-1	0.58 (14%)	0.47 (−6%)	0.27 (−1%)	0.58 (14%)
WAPA-2	0.85 (15%)	0.99 (2%)	0.34 (−3%)	0.85 (15%)
WAPA-3	0.74 (9%)	0.59 (−4%)	0.28 (4%)	0.74 (9%)
WAPA-4	0.55 (3%)	0.44 (−9%)	0.22 (−5%)	0.55 (3%)
WAPA-5	0.12 (14%)	0.13 (0%)	0.06 (−4%)	0.12 (14%)
WAPA-6	1.76 (−12%)	0.81 (−27%)	1.03 (18%)	1.76 (−12%)
	10-year low runoff (inches/season), 2025–2039 future projection and percent change from baseline[a]			
	Spring (Mar–May)	**Summer (Jun–Aug)**	**Fall (Sep–Nov)**	**Winter (Dec–Feb)**
WAPA-1	0.65 (28%)	0.54 (9%)	0.26 (−6%)	0.65 (28%)
WAPA-2	0.87 (18%)	0.72 (−26%)	0.34 (−2%)	0.87 (18%)
WAPA-3	0.62 (−8%)	0.43 (−29%)	0.25 (−4%)	0.62 (−8%)
WAPA-4	0.58 (8%)	0.38 (−22%)	0.22 − 3%)	0.58 (8%)
WAPA-5	0.11 (1%)	0.09 (−27%)	0.06 (−7%)	0.11 (−1%)
WAPA-6	1.49 (−25%)	0.78 (−25%)	0.97 (11%)	1.49 (25%)

[a] The percentage indicates the relative change compared with baseline.

with three emissions scenarios (A1B, B1, and A2) to project changes in temperature, precipitation, runoff, and other variables for about a dozen major western watersheds, including the Missouri, Upper/Lower Colorado, and Rio Grande in the Western region. Its assessment employed the BCSD technique of Wood et al. (2002) to generate downscaled translations of 112 CMIP3 projections. It noted that these projections generally do not depend on the particular emission scenario until near the middle of the 21st century. Since the 9505 Assessment uses the A1B scenario (a midrange forcing scenario between B1 and A2) and employs a bias-corrected downscaling approach, it can be viewed as essentially a middle-ground approach with respect to Reclamation (2011b); so in that sense, it may be reasonable to compare the Reclamation (2011b) and 9505 Assessment projections for the river basins they have in common. An important distinction between the results of the 9505 Assessment and Reclamation (2011b), however, is the base climate period to which the projections relate: 9505 Assessment's base period is 1960–1999, which, for temperature, means a cooler reference mean compared with Reclamation's base period of 1990–1999. Thus Reclamation's explicit projection of change in temperature for the Upper Missouri Basin (at Omaha) for the 2020s (the middle 10 years of their 2010–2039 period) is only about +1.5°F (their Table 3), cooler than 9505 Assessment projections of +2.0°F for 2010–2024 and about +3.8°F for 2025–2039 (Figure 4-5). For a better estimate of how well the two assessments' temperature change projections for the Upper Missouri Basin may agree, one must carefully examine the time series shown in Figure 40 of Reclamation (2011b), which shows an increase of about 2.5°F from the 1960–1999 period through the 2020s (close to the middle of the two 9505 Assessment 15 year period projections). Comparisons of temperature projections between Reclamation (2011b) and the 9505 Assessment for the other two basins in common [Upper Colorado (WAPA-3) and Lower Colorado (WAPA-4) in the 9505 Assessment basically comprise the Colorado Basin in Reclamation (2011b)] show fairly close agreement. The 9505 Assessment projections are slightly warmer than Reclamation's, similar to the Upper Missouri comparison. Owing to significant differences in delineation, projections for the smaller, noncontiguous WAPA-6 cannot be directly compared with Reclamation projections for the larger Sacramento and San Joaquin Basin. Nor can Reclamation projections for Rio Grande at Elephant Butte Dam region (actually encompassed in the 9505 Assessment as part of WAPA-3) be compared with the 9505 Assessment projections at Rio Grande Basin (WAPA-5).

Turning to precipitation and runoff projections, a significant difference between Reclamation (2011b) and 9505 Assessment projections is seen for the Upper Missouri Basin. The 9505 Assessment mean annual precipitation and runoff projections averaged over 2010–2039 (Figure 4-5) are about +5% and +20%, respectively, whereas Reclamation (2011b) 2020s projections are about +3% and +4% (see Reclamation Figure 40 and Table 3). These differences are unlikely to be related to the assessments' different reference period means. Note also that the 9505 Assessment's Upper Missouri area (WAPA-1; Figure 4-1) is somewhat smaller than the Upper Missouri as depicted in Figure 40 of Reclamation (2011b), which extends farther east in the Dakotas. This difference is also unlikely to be a cause of the significant differences in Upper Missouri precipitation and runoff projections between the two assessments. Comparisons of precipitation and runoff projections between the Upper Colorado (WAPA-3) and Lower Colorado (WAPA-4) Basins from the 9505 Assessment and the Colorado Basin in Reclamation (2011b) reveal that both assessments show little evidence of change in annual means over the coming decades (Figure 4-5 above; Table 3 and Figure 22 in Reclamation [2011b]). However, the 9505 Assessment projections of summer (June–August) runoff show strong decreases on the order of 20–30% for the mid-term (Figure 4-5). These summer projections cannot be directly compared with those of Reclamation (2011b) because its runoff projections were made for a warm season defined as April–July, which shows little change ("Colorado River above Imperial Dam" in Reclamation Table 3 and Figure 27). Reclamation (2011a; Figure 4a) replotted projections of runoff changes from Milly et al. (2005), which used 24 pairs of GCM simulations for 2041–2060 (relative to a 1901–1970 baseline). The analysis shows that the vast majority of the model runs show decreases in runoff over the Western region, with the exception of the Upper Missouri watershed. These results are very consistent with changes in runoff projected by the 9505 Assessment.

Christensen and Lettenmaier (2007) used downscaled and bias-corrected output from 11 GCMs to project temperature and precipitation over the Colorado River Basin, and to force the VIC model (as in the 9505 Assessment) to produce projections in runoff. They used the A2 and B1 climate scenarios (bracketing the A1B scenario used in the 9505 Assessment) and produced projections for three periods: 2010–2039, 2040–2069, and 2070–2099. The first period encompasses precisely the two 15 year 9505 Assessment projection periods. Projected changes for the 2010–2039 period using the two emissions scenarios (B1 and A2, respectively) were +2.3°F and +2.2°F for temperature, +1% and –1% for precipitation, and 0 and –1% for runoff. Christensen and Lettenmaier describe considerable variability in the magnitude, direction, and seasonality of their projected changes in precipitation. Projected precipitation changes (Figure 4-5) from the 9505 Assessment also show similar types of variability. Christensen and Lettenmaier (2007) also note that their projected runoff changes are considerably smaller than those found for the US Southwest by Milly et al. (2005) and Seager et al. (2007), which simulate runoff directly from GCMs. They state that the high spatial resolution of the VIC model (not part of the GCM-only studies) means their assessment is better able to resolve the interactions of elevation with seasonally varying evaporative trends, resulting in higher confidence in their projections. The 9505 Assessment, also using downscaling and the VIC model, does project significant summer decreases in runoff for the second half of the 2010–2039 period (Figure 4-5) for both the Upper and Lower Colorado watersheds (WAPA-3 – WAPA-4). A recent study by Cloern et al. (2011) on California's San Francisco Bay-Delta-River System suggested temperature increases and precipitation and runoff decreases in the WAPA-6 area.

NARCCAP temperature and precipitation projections (Mearns et al., 2009) can also be generally compared with the 9505 Assessment results. NARCCAP provides results from the CCSM3 (driving GCM of the 9505 Assessment) coupled with the CRCM and MM5I. An important distinction between NARCCAP and the 9505 Assessment is the greenhouse scenario used; NARCCAP uses A2, presumably resulting in considerably stronger forcing, especially later in the 21st century. Seasonal projections for 2041–2170 (relative to a 1971–2000 base period) are readily available from the NARCCAP website. Focusing on the most significant projected changes, the CCSM+CRCM temperature change projections over the southern reaches of the Western region for summer 2041–2070 (5.4–7.2°F) may be described as essentially extrapolations of the magnitude of warming found for 2010–2039 (median change of ~4.0°F) in the 9505 Assessment. Like the precipitation changes projected by the 9505 Assessment, the CCSM+CRCM results show a somewhat mixed signal over the very large Western region, depending on season and specific assessment area. Missouri watershed precipitation is projected to generally increase, whereas over some of the southern watersheds, precipitation is generally projected to decrease. It is interesting that the CCSM+MM5I projected changes in both temperature and precipitation are significantly different from both the CCSM+CRCM and 9505 Assessment projections—warming over essentially the entire Western region is projected to be weaker, whereas decreases in precipitation are projected to be much more pronounced over the southern portion of the region.

The main points of the 9505 Assessment of future climate projections over the Western region for 2010–2039 are as follows:

- Rapid warming has been occurring over the region as a whole since about 1970 with rates of about 0.45°F per decade in the north and 0.65°F per decade in the south.
- Century-scale changes in precipitation over the region generally have not been observed, although interannual and interdecadal variability can be large. The Lower Colorado watershed has seen winter precipitation increase over most of the last half of the 20th century, extending until the onset of major drought in the late 1990s.
- Mean annual temperature for the Western region is projected to increase by about 2.2°F and 3.4°F, respectively, for the near-term and mid-term periods, compared with the 1960–1999 baseline. For most of the Western region, the summer season is projected to warm the most, except for WAPA-1 and -6, which show winter warming slightly exceeding that of summer.
- Projected changes in precipitation present a mixed picture. Projections of mean annual precipitation show little evidence of change over most of the Western region except for the Rio Grande area (WAPA-5), which will likely experience decreased precipitation (mainly driven by summer drying), and the Upper Missouri area (WAPA-1), projected to have modest annual increases driven mainly by wetter springs. In addition, decreases in summer precipitation over the California Central Valley (WAPA-6) are possible for the mid-term.
- Many parts of the Western region are expected to experience changes in seasonal or annual runoff. Most annual changes are not found to be statistically significant. Most of the annual/seasonal changes are expected to be decreases (e.g., the Rio Grande area on an annual basis and the Upper and Lower Colorado mainly in summer). Runoff projections for the Upper Missouri area indicate the possibility of annual increases, driven largely by spring increases (consistent with the nature of precipitation projections).

4.4 EFFECTS ON HYDROPOWER GENERATION IN THE WESTERN REGION

4.4.1 Projection of Hydropower Generation

Projection of future annual hydropower generation (Figure 4-7) is computed by combining the revised runoff-generation relationship (Figure 4-4) with the projection of future runoff (Figure 4-5). The average simulated generation during the baseline period is computed for each of the Western assessment areas, along with their corresponding projected change in the two future periods. Similar to the style in Figure 4-5, the minimum, median, and maximum of the 9505 ensemble members are shown. To avoid

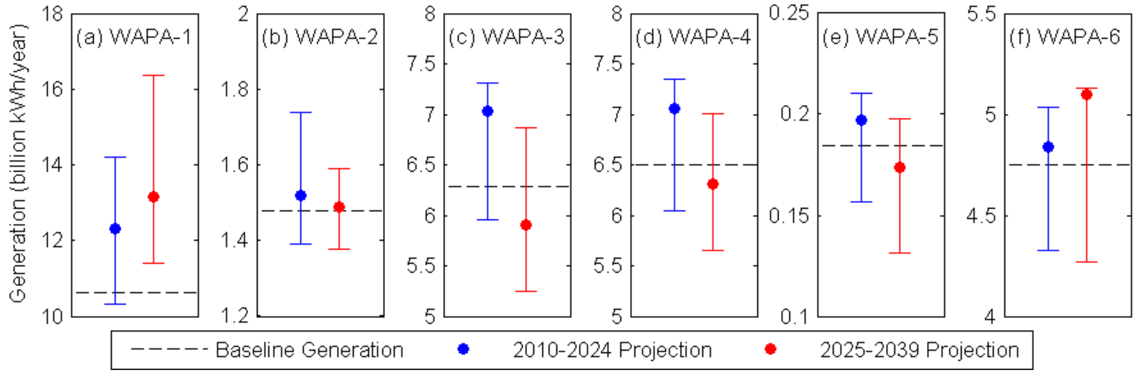

Figure 4-7. Projected annual hydropower generation in the Western region, based on observed correlations with runoff. Dashed line for baseline reference is the mean of simulated 1960-1999 annual generation across five ensemble members; circles are the 15-year mean for the median ensemble member; and the range plotted around each circle extends from the highest to the lowest ensemble member, as a measure of model uncertainty.

bias embedded in the VIC modeling, bias correction is performed for the simulated annual runoff using the USGS WaterWatch observed runoff. In Figure 4-7, the dashed line for the baseline is the mean of simulated 1960–1999 annual generation across five ensemble members; circles are the 15-year mean for the median ensemble member; and the range plotted around each circle extends from the highest to the lowest ensemble member, as a measure of model uncertainty. The numerical results are presented in tables in Appendix H. The minimum and maximum annual hydropower generation during the simulated baseline period (1960–1999), simulated near-term period (2010–2024), simulated mid-term period (2025–2039), and observed recent 20 year period (1989-2008) are also summarized in Appendix H. Detailed cumulative distributions of observed and simulated annual generation are illustrated in Appendix I for each Western assessment area.

According to the median 9505 ensemble, an increasing trend of hydropower generation is projected in the Western region, mostly in WAPA-1 (Upper Missouri). The wetting trend of WAPA-1 is consistent with the findings of the 9503 Assessment. However, the projected increase in hydropower may not be fully realized if the amount of runoff exceeds the current capacity of the system. Increasing difficulty in flood operation seems to be a major challenge related to hydropower generation in WAPA-1. Except for WAPA-1, the minimum and maximum 15 year ensemble mean ranges from decreasing to increasing, suggesting a large uncertainty bound. Although the projected change will add to the historic variability, the change is mostly on a smaller scale in the Western region. Therefore, the climate impact on WAPA-2 through WAPA-6 hydropower generation may not be significant within the assessment period. Although there could be more extremes, as suggested by simulation, the long-term change should be similar to what Western has encountered in the past 20 years, except in WAPA-1.

4.4.2 Indirect Effects

As used in this report, "indirect effects" refers to climate-related changes to federal hydropower operations that are not included in our 9505 Assessment modeling approach and that can be expected to occur in addition to changes in precipitation and runoff. For example, some changes in air temperature are addressed in the 9505 Assessment models; but air temperature changes will also affect energy demands and usage patterns, which may trigger changes in hydropower generation that are important in balancing power systems. Such an effect is highlighted early in the most recent NPPCC Briefing Book (NPPCC, 2010) and explained in the CCSP SAP 4.5 report on climate impacts on the energy sector (CCSP, 2007).

The significant increases in summer temperatures projected by the 9505 Assessment over most of the Western region (>4.0°F by the mid-term) can be expected to increase residential cooling needs and thus increase total and peak electricity demand. This is expected to be an especially significant effect coupled with projections of decreased runoff in the summer over the Colorado River Basin. This warming may also result in increased evaporation from reservoir surfaces, resulting in less water available for hydropower (CCSP, 2007). This effect is hard to confidently predict, however, as evaporation is not determined solely by water and air temperatures; other climate variables such as relative humidity, solar radiation, and cloudiness play important roles. At any rate, reservoirs with the largest surface areas (e.g., Lake Powell and Lake Mead) are those potentially most sensitive to this effect.

Other likely indirect effects on hydropower include temperature-induced changes in water quality and aquatic habitat condition (Meyer et al., 1999), e.g., longer periods of low summertime streamflow and possibly increased algae growth resulting in eutrophic conditions in reservoirs. Such effects may, depending on location and severity, require changes in hydropower project operation that reduce power production (CCSP, 2007).

Another indirect effect brought about by increasing warm-season temperatures may include increasing electricity demand and an associated effect on GHG mitigation activities if renewable energy sources such as hydropower become less reliable because of decreased warm-season runoff. Many states in the Western region have established renewable portfolio standards; less hydropower generation in the warm season (e.g., in the Colorado Basin) may affect future development of other renewable capacity (e.g., solar and wind) and/or result in utilities purchasing more electricity generated by renewable sources from other states.

4.4.3 Implications for Federal Power in the Western Region

WAPA-1: The 9505 Assessment projects about a 20% increase in annual runoff. The large WAPA-1 reservoir storage provides flexibility in water management and is closely tied to generation based on snowpack conditions and associated runoff levels. Additional sources of hydroelectric generation variability are water control manuals and/or policies used by USACE and Reclamation in their operation of the P-SMBP– Eastern Division facilities for other program purposes. As the operator of the six main stem generation facilities on the Missouri River, USACE annually provides a forum for public participation on current hydrologic conditions and projected system regulation as it relates to implementing the final Annual Operating Plan (AOP). Currently, regulation of the system is accomplished in accordance with the USACE Master Manual to serve authorized project purposes (flood control, water supply and water quality control, irrigation, navigation, power, recreation, fish and wildlife, historic and cultural properties) while enhancing habitat construction, including emergent sandbar habitat and shallow water habitat, flow modifications, propagation/hatchery support, research, monitoring and evaluation, and adaptive management. The USACE AOP, including its 4 year forecast for P-SMBP–Eastern Division is provided to Western to use as a primary building block in establishing the levels of generation it will have available to meet its contractual commitments and to market each year.

The marketing for P-SMBP hydropower is administered by two Western power systems: P-SMBP–Eastern Division by the Upper Great Plains (i.e., WAPA-1) and P-SMBP–Western Division by the Rocky Mountain region (i.e., WAPA-2). As noted earlier, power generated at the six Missouri River main stem hydropower plants is just one purpose; P-SMBP also provides for other purposes such as flood control, navigation, irrigation, municipal, rural and industrial water usage, recreation, and fish and wildlife benefits. As a part of that comprehensive program, Western markets hydropower from the P-SMBP – Eastern Division on a project-wide basis that integrates all hydropower resources as if they constitute a single component. The P-SMBP–Eastern Division marketing plan establishes criteria that specify the conditions under which Western will sell the P-SMBP–Eastern Division power. These criteria include such issues as the geographic area for sales of the electricity, types and amount of electric service offered for sale, customer eligibility, contract term, and other issues reflecting Western's mission, legal requirements, and other marketing practices and policies. P-SMBP–Eastern Division markets capacity based on adverse water conditions in WAPA-1, thus ensuring Western's ability to make a firm commitment of capacity to meet a portion of its customer peak load even in adverse water conditions. However, energy in WAPA-1 is marketed on an average historical energy production basis, which allows Western the ability to offer a greater amount of energy on a firm basis to its customers knowing that energy market purchases will be made at certain times and surpluses will be sold into the energy markets at other times. More information about Western's marketing plan is available at http://www.wapa.gov/ugp/powermarketing/2021PMI.htm.

Western's Upper Great Plains region, in cooperation with Reclamation and the USACE as the generating agencies, are responsible for setting rates and ensuring repayment of costs associated with P-SMBP–Eastern Division power produced from the six hydropower plants on the Missouri River, as well as the hydropower plants at Canyon Ferry and Yellowtail in Montana. Revenues and costs for both the Eastern Division and Western Division of P-SMBP are combined and recorded as a collective P-SMBP, both historically and when estimating for future repayment. This methodology allows for the three cooperating agencies to administrate the various operations, generation, and transmission facilities that all must be repaid efficiently under the P-SMBP program. Rates for the P-SMBP power system are collective and are impacted by water conditions (both drought and surpluses) and are set to recover annual power and transmission O&M expenses, power generation and transmission investments, portions of the multi-purpose O&M and investment costs of the dams and storage features, deferred drought deficits, associated interest on unpaid capital costs for the entire P-SMBP power system, and irrigation aid.

A single Power Repayment Study (PRS) for P-SMBP, both Eastern and Western Divisions, is prepared annually by Western, in cooperation with Reclamation and the USACE, in accordance with authorizing legislation and DOE orders. The PRS summarizes historic income, expenses, and investments to be repaid from power revenues. It also estimates income, expenses, and investments for future years. The PRS shows historical application of revenues, as well as the annual repayment of power system production and transmission costs, and other costs assigned to power for repayment. The PRS is used to determine if power revenues are sufficient to pay all project costs allocated to power for repayment within the appropriate repayment period and are used to set power rates.

The WAPA-1 hydroelectric P-SMBP–Eastern Division capacity and energy resources are marketed, as mentioned earlier, via long-term firm electric service (FES) contracts. As a mitigation of risk, the P-SMBP–Eastern Division FES contracts contain a clause allowing Western to adjust firm energy and capacity allocations in response to changes in hydrology and river operations with reasonable public notice and comment period. In addition, the FES contracts contain provisions for Western to limit customer monthly load factors to 70% with a 3 year notice to the customers. To date, Western has not used these contract provisions.

WAPA-2: The 9505 Assessment projects hydroelectric generation variability caused by climate change in the WAPA-2 area that is of a smaller order than the historic variability. The historic generation variability is accommodated by energy purchases, surplus energy sales, and contractual flexibility. Sources of historic hydroelectric generation variability include changes in water demand, reservoir reoperation for the benefit of aquatic species, and extended hydropower plant maintenance outages, in addition to the variability of reservoir inflows. The timing of water deliveries has changed as water use has shifted from agricultural to municipal demands. Municipal water demand is less predictable on a short-term basis. Reclamation has also changed the operation of reservoirs to improve the habitat of both endangered aquatic species and sport fisheries. The timing, frequency, and length of hydropower plant maintenance outages have changed owing to increased requirements for plants that have exceeded typical design lives.

WAPA-2 hydroelectric generating resources are marketed as long-term FES of the LAP. Fixed monthly amounts of firm energy and capacity are committed to individual FES customers. The customers may schedule their energy allotments within a month at their discretion, as long as the scheduled amount in any hour does not exceeded their monthly capacity and is not less than a monthly minimum schedule. Both the generation and generating flexibility of the LAP hydropower plants are, therefore, contractually committed to the FES customers. The total monthly energy and capacity allocation was established, using historic reservoir inflow records, with Reclamation's monthly reservoir operating models. Western marketed the monthly energy available 50% of the time while taking into account losses due to transmission and power system regulation. Western anticipated that the energy generated would exceed or fall short of contractual commitments in equal proportions over time. Western more conservatively marketed the monthly capacity available 90% of the time while taking into account generating reserve requirements and expected maintenance outages.

Short-term generation surpluses or deficits caused by hydrologic conditions or any other reason are compensated by seasonal or real-time purchases or sales of energy on the open market. Every month, Reclamation projects a range of LAP generation for the upcoming 12 month period, with expected plant maintenance outages and water demands taken into account. Reclamation models reservoir operations based on three hydrologic cases: the reasonable minimum reservoir inflow case, the most probable case, and the reasonable maximum case. The reasonable minimum seasonal reservoir inflow is the amount of inflow that will be exceeded 90% of the time. The most probable reservoir inflow is that with a 50% exceedance probability, and the reasonable maximum is an amount with a 10% exceedance probability. Reclamation arrives at the range of seasonal reservoir inflows by employing a weighted multivariate linear regression with indices for snowpack, soil moisture, and total precipitation. Reclamation distributes the seasonal reservoir inflow among the months of the season using typical inflow profiles from historic dry, average, and wet years. Reclamation also annually updates the historical record used in its regression analysis so that any actual impacts of climate change are reflected in both the amount and distribution of reservoir inflow indicated by the regression analysis. Based on Reclamation's projected range of generation and expected market prices, Western either arranges a seasonal purchase or sale of energy, or decides to wait and buy or sell energy in real time—usually a combination of both. Western is required to recover all capital, operating, and maintenance expenses attributed to LAP hydropower facilities through the FES rate setting process. Revenue from energy sales reduces the repayment obligation and future FES rates, and purchases increase the repayment obligation and future rates.

Long-term generation surpluses or deficits may be addressed by exercising an FES contract clause allowing Western to adjust firm energy and capacity allocations, with reasonable notice, in response to changes in hydrology and river operations. Western may also decide to continue to purchase or sell energy to compensate for long-term generation changes. Western's FES customers ultimately bear any financial risk of long-term generation variability directly by rate changes or indirectly by allocation changes.

WAPA-3 and -5: The 9505 Assessment projects hydroelectric generation variability, caused by climate change in the WAPA-3 area, that is less than the historical variability. Historically, inflow to Upper Colorado River Basin reservoirs has been highly variable. This historical inflow variability has been recognized and accommodated with the large storage capacity of the project reservoirs, operational flexibility of the hydropower facilities, and contractual flexibility in delivering that power to customers.

Sources of historical hydroelectric generation variability include changes to water demand, reservoir reoperation for the benefit of aquatic species, and extended hydropower plant maintenance outages, in addition to the variability of reservoir inflows. Western and Reclamation have also changed reservoir operation to improve the downstream habitat of endangered species, recreational use, and sport fisheries.

The timing, frequency, and length of hydropower plant maintenance outages have also increased with the aging hydropower plants and associated hydropower facilities, most of which are 50 years old or older.

Additionally, consumptive demands on Colorado River Basin water are gradually increasing as the seven Colorado River Basin states increase their water depletion from the river. The long-term trend is for less generation from WAPA-3 hydropower plants as these depletions continue. This trend is long anticipated,[5] so current power contracts have been structured to allow for allocation changes to power customers.

Most WAPA-3 hydroelectric generating resources are marketed as long-term FES or SLIP. The SLIP FES contracts contain a clause allowing Western to adjust firm energy and capacity allocations, with reasonable notice, in response to changes in hydrology and river operations. The contracts are structured to have a floor level of capacity and energy that is guaranteed by Western.

Western purchases to firm its capacity to the floor generation level. When additional hydropower is available as a result of improved runoff conditions, Western allocates additional energy and capacity on a monthly basis at the current power rate until the maximum allocation to customers is reached. In the rare case when full customer allocations have been reached, Western can then sell the surplus on the regional power market to customers and other utilities. SLIP also uses the Colorado River Storage Project (CRSP) Basin Fund, a revolving fund used to fund O&M of the CRSP hydropower project, to purchase firming power when needed. A balance is maintained in the Basin fund sufficient to accommodate continued operation during low-runoff periods. Periodically, a risk analysis is performed on the Basin Fund to ensure that the balance is still sufficient given changing hydrological and power system conditions. An additional risk management tool, the cost recovery charge, is included in the firm power rate. The cost recovery charge is a contractual method of passing the cost of firming purchases directly to customers in the event that the Basin fund is depleted to a predetermined level by increased firming purchases.

The remainder of WAPA-3 hydroelectric facilities (Provo River Project) and all of WAPA-5 (Falcon-Amistad Project) are marketed as “pay all-take all.” Under this arrangement, power customers are not guaranteed a quantity of power but take all the power generated by the projects. The customers pay the total annual revenue requirements each year. In these projects, the entire risk of hydrological variability is shifted from Western to the power customers.

Western has developed extensive capabilities to forecast and model power system runoff, generation, and firming purchases to mitigate the risk of hydrological variability and the variability in the cost of firming power. The Western staff is engaged in continual evaluations and reevaluations of conditions as runoff forecasts change. This enables Western to anticipate changes to operations and quickly adapt by changing power deliveries to customers, increasing or decreasing firming purchases, and reacting to changes in the regional power system.

WAPA-4: The 9505 Assessment projects hydroelectric generation variability caused by climate change in the WAPA-4 area that is less than the historical variability. While it is true that the three lower basin dams—Hoover, Davis and Parker—are completely dependent on Upper Colorado River Basin reservoirs and their highly variable inflows, the large storage capacity of Hoover Dam has successfully weathered the current 11 year drought. To date, Hoover Dam has never failed to release enough water to meet downstream water demands.

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[5] The Upper Colorado River Commission publishes an annual report, as required by Article VIII (d) (13) of the Upper Colorado River Basin Compact, that details future depletions in the upper Basin states to at least the year 2060. The annual reports, which have been published for over 60 years, are transmitted to the US president and the governors of the Upper Basin States of Colorado, New Mexico, Utah, and Wyoming. Reclamation has incorporated these future depletions into its Colorado River planning models used to project future reservoir operations.

During the last 11 water years, the Upper Colorado River Basin has exhibited very few years with significant above-average snowpack and reservoir inflows. With Hoover Dam outflows exceeding the releases to Hoover Dam from upstream reservoirs, the Hoover Dam elevation has continued to decline steadily over the drought period. In response to the declining Hoover Dam elevations, the Department of Interior issued its December 2007 *Record of Decision on the Colorado River Interim Guidelines for Lower Basin Shortages and the Coordinated Operations of Lake Powell and Lake Mead*, otherwise known as the Interim Guidelines. For the first time, shortage criteria were put in place that govern the operation of Hoover and Glen Canyon Dams. The shortage criteria basically state that at certain Hoover Dam elevations, downstream water demands will be reduced accordingly and, subsequently, power production will be reduced. In November 2010, the Hoover Dam elevation came within 7 ft of triggering the shortage criteria. Not since May 1937 (when Hoover Dam was initially filling) has the Hoover Dam elevation been this low.

The low elevation at Hoover Dam also affects the operation of its hydro units. Certain units were not designed to operate at such low heads and consequently are operating at only one-third of their rated capacities. In 2005 Reclamation, in consultation with Western and the Hoover contractors, began making modifications to the Hoover units in an effort to reclaim lost generating capacity at low lake levels. A total of 95 MW has been reclaimed to date with an additional 45 MW expected within the next 5 years. A unit control modernization program was initiated in 2009 and completed in 2010. Basically, all mechanical and analog control equipment was replaced with digital controls. In 2010, a study was commissioned to look at the feasibility of replacing the existing turbine runners with wide-head turbines. Later that year, Reclamation awarded a contract for one wide-head turbine installation and associated modeling studies for Hoover unit N8. Turbine installation is currently scheduled for February 2012. This will increase the capacity and energy production at low lake levels and the operating efficiency of Hoover unit N8 over a wide range of lake elevations. If Hoover unit N8 operates as expected with its new wide-head turbine, then additional units will be targeted for wide-head turbine replacement.

WAPA-4 is actively participating in Reclamation's Colorado River Basin Water Supply and Demand Study (CRBWSDST). The purpose of the CRBWSDST is to conduct a comprehensive assessment to define current and future imbalances in water supply and demand in the Colorado River Basin—and in adjacent areas of the Basin states that receive Colorado River water—for approximately the next 50 years and to develop and analyze adaptation and mitigation strategies to resolve those imbalances.

CRBWSDST will characterize current and future water supply and demand imbalances in the Basin and assess the risks to Basin resources. Resources include water allocations and deliveries consistent with the apportionments under the Law of the River; hydroelectric power generation; recreation; fish, wildlife, and their habitats (including candidate, threatened, and endangered species); water quality, including salinity; flow and water -dependent ecological systems; and flood control.

The marketing of WAPA-4 hydroelectric resources is unique, but the energy produced by all three dams depends directly on downstream water demands unless Hoover Dam is spilling water or operating under shortage conditions. Hoover Dam is a storage dam and the resource is marketed as contingent capacity with associated firm energy. This means that Hoover contractors are allocated only the energy that can be generated from the available capacity. The rated capacity of Hoover Dam is 2074 MW but the available capacity is currently 1661 MW. The existing Hoover contracts expire in 2017, and an extensive remarketing effort is currently under way.

Parker and Davis Dams are run-of-the-river dams, and their elevations are strictly controlled because of environmental and recreational concerns. The Parker-Davis resource is marketed as firm capacity and firm energy. A remarketing effort was undertaken in 2007 and put in place at the start of FY 2009. A resource pool was created that resulted in 12 new Parker-Davis contractors. Western began purchasing power to meet firm obligations in FY 2009 and will continue to do so, if necessary, for the foreseeable future.

WAPA-6: Modeling results from the 9505 Assessment anticipate that hydroelectric generation variability associated with climate change in the WAPA-6 area would be less than is indicated by the historical data. Historically, inflow to California reservoirs has been highly variable. What could change, however, is the timing and nature of reservoir inflows. For example, increased temperatures could result in a smaller snowpack. Thus more of the reservoir inflows could be from rainfall rather than from melting snowpack. This could have implications for water and hydropower operations and accomplishments. The historical inflow variability has been recognized and accommodated with the relatively large storage capacity of the project reservoirs, operational flexibility of the hydropower facilities, and contractual flexibility in delivering power to customers.

In addition to precipitation and runoff variability, other sources influencing historical hydroelectric generation variability include changes to water demands, reservoir reoperation for the benefit of aquatic species, and the need to perform both routine and extraordinary maintenance on power generation–related facilities to ensure that they continue to be operated safely and reliably. Reclamation has also changed the operation of reservoirs to improve the downstream habitat of endangered species, recreational use, and sport fisheries. The timing, frequency, and length of hydropower plant maintenance outages have also increased, not only as a result of aging hydropower plants and associated hydropower facilities, most of which are 50 years or older, but also because of budgetary constraints and the need for the power generation facilities to remain operational during peak energy consumption time periods. This has resulted in either deferring maintenance, performing it at less optimal time periods, or determining that an extended time interval is required when the maintenance outage occurs because of the need to take additional corrective actions above and beyond what may have been originally contemplated.

The WAPA-6 hydroelectric facilities (Central Valley Project in particular) are marketed as a "take or pay resource." Under this arrangement, since power customers are not guaranteed a defined quantity of power, they, and not Western, assume the entire hydrologic variability risk. After project-use and first-preference loads have been satisfied, power customers then receive any net hydropower generation in proportion to their allocation percentages. The power customers are responsible for paying their pro rata shares of the annual power revenue requirements each year. One significant potential impact associated with climate change for the WAPA-6 assessment area is a potential seasonal distribution adjustment of generation from the more valuable summer season to the winter season. A change in existing reservoir operation may be desired and/or required to better align projected runoff with reservoir storage capacities. However, such changes, especially if they involved flood control space reservations, would have to be coordinated with the USACE.

Western has developed tools to forecast hydropower system generation to mitigate the risk of hydrological variability. The Western staff is engaged in continual evaluation of conditions as runoff forecasts change. This enables Western to anticipate changes to power operations and quickly notify power customers of changes in the projects' power production.

5. THE SOUTHWESTERN REGION

This section describes SWA Section 9505 Assessment results for the Southwestern region and the federal hydropower projects located there. The section is organized into four subsections, the first of which explains how the region was subdivided into areas of analysis. The first subsection also presents information on the region's federal hydropower system, power marketing by Southwestern, and major water management issues within the region. The second subsection describes existing hydrology and generation patterns in the region under the current climate (i.e., the baseline for comparison to climate change projections). The third subsection contains results of the climate change projection that was done for this Section 9505 Assessment, along with a literature-review comparison to climate studies by others. The fourth subsection focuses on potential changes to federal hydropower generation under the projected future climate and possible adaptation options, responding to the effects of climate change.

5.1 REGIONAL CHARACTERISTICS

The Southwestern region, as defined for this assessment, covers rivers that run through the Ozark Plateau, southern Great Plains, and Texas coastal plains (Figure 5-1). There are 24 hydropower projects in this region, all of which are owned and operated by USACE. There are no Reclamation hydropower projects in this region. The USACE projects in the Southwestern region have a total installed capacity of 2,174 MW and an average annual generation of 5.8 billion kWh (Section 5.1.2 and Appendix B). The region is subdivided into four areas of analysis:

- Southwestern Area 1 (SWPA-1): Ozark Plateau rivers in Missouri and northern Arkansas (Osage, upper White, and Salt River Basins)
- Southwestern Area 2 (SWPA-2): the Arkansas River Basin in Oklahoma and Arkansas, plus the Broken Bow project in the Red River Basin, included because of interconnected system reason
- Southwestern Area 3 (SWPA-3): the Red and Brazos River Basins in Oklahoma and Texas, plus smaller, upstream parts of the Ouachita River Basin draining the southern side of the Ouachita mountains in Arkansas and Oklahoma
- Southwestern Area 4 (SWPA-4): the Neches River Basin in southeastern Texas

5.1.1 Areas of Analysis

There is generally less variety in the physical and climatological differences among the four areas of analysis in this region than there is for the Bonneville or Western regions described in the previous two sections.

The first analysis area (SWPA-1) is located on the northern portion of the Ozark Plateau. This area includes the upper White and Osage River Basins, as well as the Salt River drainage in northeastern Missouri where the USACE Clarence Cannon project is located. The total drainage area of watersheds contributing water to projects in this area is approximately 22,000 mile^2. Elevations range from 300 to 2,400 ft amsl with a median of 981 ft amsl. As a whole, the Southwestern region is significantly lower in elevation than the Bonneville or Western regions, and the topography strongly influences surface water hydrology. Land cover in the SWPA-1 area is a mix of cropland (37%), cropland-natural vegetation mosaic (34%), deciduous broadleaf forest (12%), and grassland (9%).

The second analysis area (SWPA-2) is defined by the Arkansas River Basin upstream of the USACE Dardanelle project. This is a very large river basin that extends upstream to the Continental Divide in Colorado. Total drainage area is about 154,000 mile^2. Elevations vary greatly, from over 14,000 ft amsl in the Rocky Mountains in Colorado to around 300 ft amsl in the vicinity of the hydropower projects that are

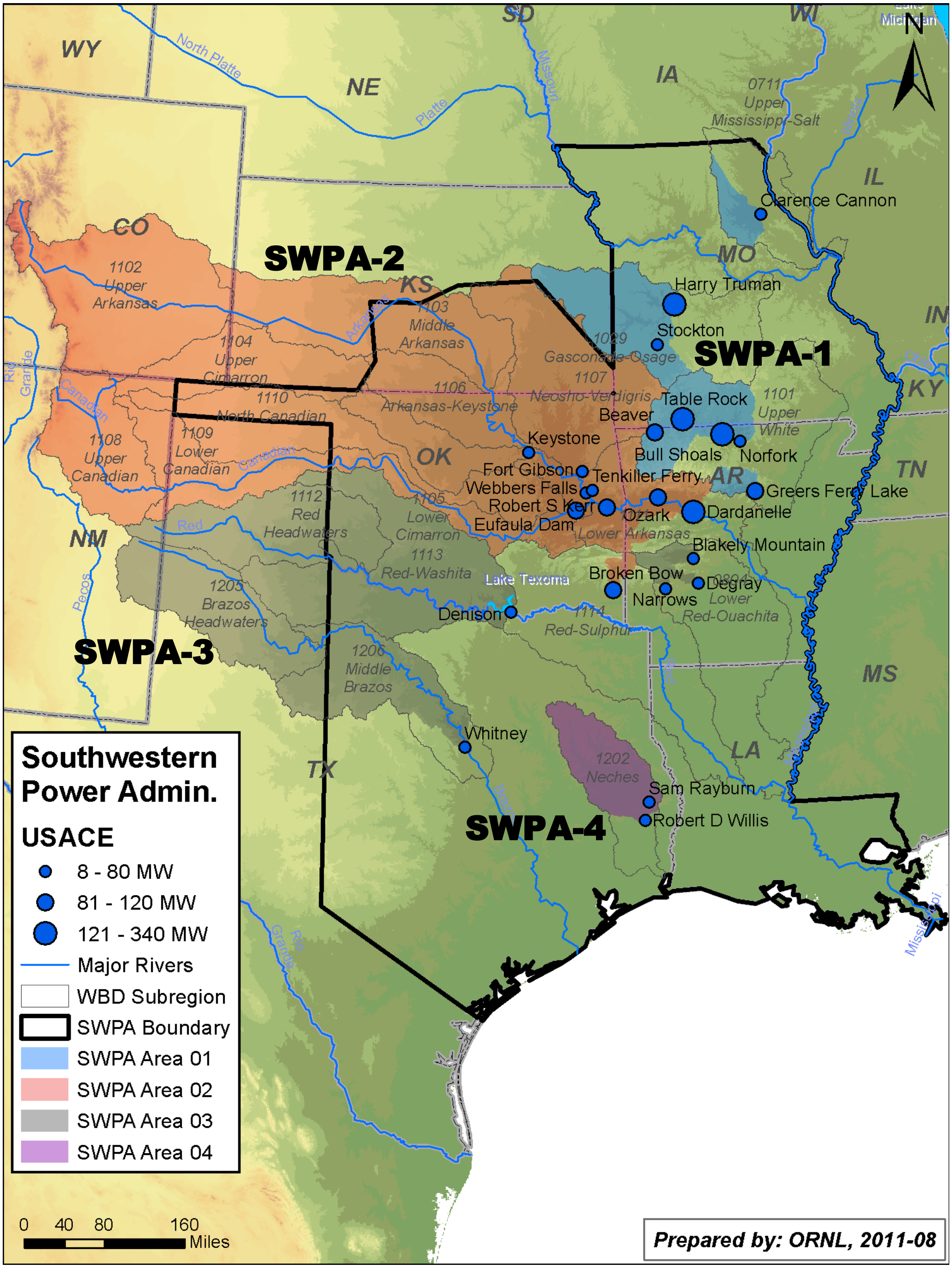

Figure 5-1. Map of the federal hydropower projects and analysis areas in the Southwestern region.

clustered in the eastern end of the river basin. The median elevation is 2,392 ft amsl. Although this area includes high-elevation parts of the Rocky Mountains, most of the runoff to the projects originates locally, in the eastern part of the area. Land cover is mostly grassland (68%) with smaller amounts of cropland (17%), cropland–natural mosaic (5%) and woody savanna (4%).

The third analysis area (SWPA-3) covers three different river basins that drain two different areas: the Red and Brazos River Basins in the arid plains of southwestern Oklahoma and the Texas Panhandle, and the Ouachita River Basin in the southern portions of the Ouachita Mountains/Ozark Plateau, mostly in Arkansas. The total watershed area is moderately large, 68,744 miles^2. Elevations range from almost 5,000 down to 300 ft amsl. Grasslands cover 82% of the watershed.

The fourth analysis area (SWPA-4), in the upper half of the Neches River Basin, is the lowest and one of the smallest of all of the 9505 Assessment areas. Its watershed area is 7,571 miles^2, and elevations range between 774 and 72 ft amsl. Land cover is a diverse mix of cropland–natural mosaic (37%), mixed forest (25%), woody savanna (22%), cropland (3%) and evergreen broadleaf forest (3%).

5.1.2 Federal Hydropower System

As mentioned earlier, all of the federal hydropower projects in the Southwestern region are owned and operated by USACE. There are 24 USACE hydropower plants in the region, ranging in size from Bull Shoals, with an installed capacity of 340 MW, to the Robert D. Willis project, with a capacity of only 7.4 MW. Total nameplate capacity is 2,173.7 MW, but total overload capacity is substantially more, 2,478.4 MW. This is important, because hydropower operations in the region are often in a peaking mode that can be operated in the overload range. Approximately half of the hydropower capacity in this region is in SWPA-1 (Table 5-1). The average age of these USACE projects is 47 years, and they are suffering the same challenges of aging infrastructure as federal projects elsewhere. A complete listing of the projects in this region is located in Appendix B.

Table 5-1. Hydropower distribution among the areas of analysis in the Southwestern region

Area no.	Major watersheds	Number of Plants			Total installed capacity[a] (MW)	Average annual generation[b] (million kWh/year)
		USACE	Reclamation	Total		
SWPA-1	Upper White, Osage and Salt	8	0	8	1,092	2,248
SWPA-2	Arkansas	9	0	9	754	2,791
SWPA-3	Red, Brazos and Ouachita	5	0	5	269	623
SWPA-4	Neches	2	0	2	59	155
Total		**24**	**0**	**24**	**2,174**	**5,817**

[a] Southwestern total nameplate capacity. Includes both conventional hydro and reversible (pumpback capability).
[b] Southwestern average annual generation from October 1970 to September 2008 (fiscal year).

5.1.3 Multi-Purpose Water Management Issues

The water resources management challenges in the Southwestern region are similar to those in the Bonneville and Western regions (Sections 3.1.3 and 4.1.3). Although the rivers in the Southwestern region do not have migratory fisheries management problems of the magnitude of those in the Columbia River or California, the hydropower projects are impacted by endangered species protection issues—such as for the interior least tern—and by recreational fisheries management. Additionally, growing demand for municipal and industrial water supply is one of the most important water resources issues in the Southwestern region. The struggle to provide water to new users is clearly evident in this region.

The water storage reallocation at Lake Texoma (the Denison project in SWPA-3) is a relevant example of how competing water uses are adversely impacting hydropower in the Southwestern region. The USACE recently finalized the reallocation of 150,000 acre-feet of storage in Lake Texoma from the hydropower purpose to municipal water supply (USACE, 2006). In addition to the loss of storage, Southwestern's concern throughout the Lake Texoma reallocation process has been the undervaluation by USACE of the impact to hydropower. The impact of the Lake Texoma water storage reallocation, as evaluated by Southwestern, included loss of both capacity and energy resulting in estimated annual replacement power purchases of $1.5 million, significantly higher than the USACE estimates. Ultimately, for simplification purposes, USACE determined that credits to Southwestern for the loss to hydropower would be equal to the total payment collected from the water supply users for the reallocated storage. Southwestern continues to maintain its objections to the undervaluation of the impact to hydropower in USACE's storage reallocation studies.

Another recent storage reallocation case in the Southwestern region is the White River Minimum Flows project, which provides storage for minimum flow releases at the Bull Shoals and Norfork projects in Arkansas (SWPA-1). By law, Southwestern determined the impacts to federal hydropower resulting from the reallocation. The total present value of losses to federal hydropower was determined to be $52,576,600. In this unique case, the authorizing legislation provided that losses to federal hydropower would be offset by a reduction in the costs allocated to the federal hydropower purpose. These types of impacts usually fall on rural electric cooperatives and municipalities that do not have resources to absorb them.

Storage reallocations, such as the Lake Texoma water supply case and the White River Minimum Flow reallocation, will continue to impact the Southwestern region in the future. Competing interests with water-based recreation, water quality, and other environmental issues are also active in the Southwestern region.

5.1.4 Power Marketing by Southwestern

Southwestern, established in 1943 by the Secretary of Interior, markets hydroelectric power from 24 USACE projects to 102 customers (78 municipalities, 12 distribution cooperatives, 9 generation and transmission cooperatives, and 3 military installations) in 6 states (Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas). Southwestern's total installed capacity is 2,174 MW and total capacity contracted by its customers was 2,053 MW in FY 2008.[6] Table 5-2 breaks down total energy sales in FY 2008 by source and customer type. The total billings associated with FY 2008 energy sales were $168,533,371 (Southwestern, 2008b). Southwestern also operates 1,380 miles of high-voltage transmission lines. Revenues from transmission for third parties represented only 10% of the total gross operating revenue in FY 2008.

Southwestern conducts three annual PRSs: one for the Integrated System, one for Sam Rayburn Dam and one for Robert D. Willis Dam. As a way to provide power at the lowest possible cost, Southwestern's Annual Performance Plan includes the objective of keeping O&M costs per kilowatt-hour below the national median for public power (Southwestern, 2010a).

[6] Besides the installed capacity, many projects have overload capacity, upward of 2,478 MW for the 24 projects.

Table 5-2. Source and distribution of energy (FY 2008). *Source:* Annual Report 2008

		Millions kWh
Energy source	Generated by USACE Plants	7,401.8
	Interchange	135.8
	Losses purchases	76.7
	Direct purchases	6.1
	Contract exchange	0.1
Total sources		**7,620.5**
Energy distribution	Cooperatives	4,963.6
	Municipalities	2,142.4
	Interchange	118.7
	Losses	166.4
	Government agencies	227.4
	Utility companies/others	2.0
Total distribution		**7,620.5**

Southwestern's sales are governed by the following five rate schedules (Southwestern, 2010b):

1. **Hydropower and energy sold to Sam Rayburn Dam Electric Cooperative** (SRDEC). Sam Rayburn (in SWPA-4) has been marketed as an isolated project since starting operation in 1966, under contract with SRDEC. Southwestern's 2008 PRS called for a rate increase of 14.3%. The previous rate was deemed insufficient to meet cost recovery criteria owing to an increase in the USACE's projected O&M costs. The new rate has been approved for the period from January 1, 2009 through September 30, 2012 (Federal Register, 2008b).

2. **Hydropower and energy sold to Sam Rayburn Municipal Power Agency** (SRMPA). Robert D. Willis (in SWPA-4) is an isolated project and is not federally financed. Funds for USACE construction of the project were provided by SRMPA. The existing contract between Southwestern and SRMPA determines that SRMPA will pay all annual O&M and capital replacement expenses associated with this project through the rate paid to Southwestern; and, in turn, it will receive all power and energy produced at the project for a period of 50 years. This project experienced a 14% increase in rates starting in October 2008 after revised O&M cost projections by USACE made previous rates insufficient according to the PRS.

3. **Nonfederal Transmission/Interconnection facilities service.**

4. **Excess energy** at $0.0086/kWh.

5. **Hydro peaking power** entitles customers in the Integrated System to 1,200 kWh of peaking energy per kilowatt of peaking contract demand during each contract year. Additional supplemental peaking energy will be furnished if and when it is determined by Southwestern to be available. For each hour during which peaking power is provided at a rate greater than that in the contract, there is a capacity overrun penalty for the customer. On the other hand, if not enough power is available to meet contract commitments, it is Southwestern's responsibility to purchase

power from other sources. This rate schedule is only applicable to wholesale customers, which have contractual rights with Southwestern.

6. The **capacity charge** for hydro peaking power is $4.06/kilowatt-month.

7. The **energy charge** for hydro peaking power is $0.0086/kWh, plus an adder of $0.0067/kWh to cover costs incurred by Southwestern for purchased power, unless the customer is under a contract support arrangement. This adder may be adjusted up to twice a year to reflect differences between the estimated and actual cost of Southwestern's purchased power. The **supplemental peaking energy charge** is also $0.0086/kWh.

Integrated System capacity and energy charges increased by 16% and 5%, respectively, in 2009. The 2009 PRS determined that such an increase was needed to account for increases in investments, replacements, Southwestern's marketing costs, and O&M at USACE facilities (Southwestern, 2009). Current rates in the Integrated System have been approved on a final basis until September 30, 2013.

Southwestern converted all of its full load factor, firm power contracts to peaking contracts by 1987. Southwestern decided that was the best way to market power from its Integrated System given the limited storage capacity of the projects and the heavy reliance on unpredictable storm inflows (Southwestern is a rain-based system while Western and Bonneville are snow-based systems) (Southwestern, 2008a). The capacity allocations in current peaking contracts derive from Southwestern's 1980 final power allocations and are guaranteed to customers beyond the terms of their current contracts. Southwestern acknowledges that changes to those allocations would force customers to procure new sources of capacity and energy and new transmission agreements to receive the energy, which would take multiple years and millions of dollars to establish. Therefore, as contracts expire, Southwestern will offer to enter into peaking contracts for the sale of a like amount of capacity with the associated annual 1,200 kWh peaking energy per kilowatt of contract capacity. Additionally, Southwestern has maintained that these customers are entitled to receive compensation for the replacement costs derived from losing hydropower benefits, in the event of a modification in their capacity entitlements due to storage reallocations by USACE.

The USACE receives annual appropriations from Congress to cover annual O&M expenses at the hydropower facilities. To fund nonroutine maintenance, rehabilitation, and replacement of USACE hydropower facilities, Southwestern, USACE, and the federal hydropower customers in the Southwestern region have established a customer financing program. Once the customer-funded maintenance projects are completed, the majority of the projects become capitalized assets (Southwestern, 2006). Southwestern, USACE, and Southwestern Power Resources Association (the main customer representative in the Southwestern region) hold an annual council to assess and prioritize nonroutine maintenance needs at the USACE hydropower facilities. The federal hydropower customers ultimately approve which projects will be funded over the next year through the customer financing program.

Southwestern has limited banking arrangements with certain customers by which excess power generated by USACE and marketed by Southwestern is valued and its value banked with the customer. Southwestern can then use those funds to purchase energy from the customer when the system needs additional energy, if the customer has power available (Southwestern, 2008b). Southwestern has a portfolio of funding mechanisms for purchasing power, including receipts authority, alternative financing authority, continuing funding authority, pre-collected receipts, and the purchased power adder and adder adjustment included in Southwestern's system rates. Additionally, to adjust to the drought conditions Southwestern experienced in 2005–2006, Southwestern engaged its customers in a temporary peaking energy deferral program; under it, customers voluntarily took less peaking energy than their contract entitlements in 2006 and agreed to receive the deferred volumes of peaking energy over the following 3 years (Southwestern, 2006).

5.2 WATER AVAILABILITY AND HYDROPOWER GENERATION

5.2.1 Observed Hydrology and Generation

The 1971–2008 average annual, spring (March, April, and May), summer (June, July, and August), fall (September, October, November), and winter (December, January, and February) temperature, precipitation, runoff and generation are summarized in Table 5-3 for the four Southwestern assessment areas. Using drainage area as a weighting factor, the average across the entire Southwestern region is also computed. The mean annual precipitation and runoff in the Southwestern region are 29.0 and 4.1 in., respectively. Southwestern has the second-highest precipitation but the second-lowest runoff among the four PMAs. The evaporation is significant and the runoff to precipitation ratio is low at 14%. Furthermore, since roughly a third of the 24 hydropower projects are run-of-river and several of the storage projects have relatively small conservation pools, the effective storage and head for hydropower generation are limited. Combining all the factors, the USACE hydropower projects in the Southwestern region provide the least hydropower generation among the four PMAs.

Table 5-3. Summary of the 1971–2008 average temperature, precipitation, runoff, and generation for the Southwestern assessment areas.

	Temperature (F)					Precipitation (inches)				
	Annual	**Spring[a]**	**Summer[a]**	**Fall[a]**	**Winter[a]**	**Annual**	**Spring**	**Summer**	**Fall**	**Winter**
SWPA-1	56	56	76	57	34	43.0	12.7	12.0	11.5	6.8
SWPA-2	55	55	76	56	35	27.1	8.1	9.2	6.5	3.3
SWPA-3	61	61	80	62	42	26.5	7.6	8.3	7.0	3.6
SWPA-4	66	65	81	67	49	48.6	12.2	10.7	13.0	12.7
SWPA	57	57	77	58	37	29.0	8.5	9.2	7.3	4.0
	Runoff (inches)					**Generation (million kWh)**				
	Annual	**Spring**	**Summer**	**Fall**	**Winter**	**Annual**	**Spring**	**Summer**	**Fall**	**Winter**
SWPA-1	12.8	4.9	2.8	2.0	3.1	2248	743	609	303	593
SWPA-2	3.6	1.4	0.8	0.6	0.8	2791	892	745	472	682
SWPA-3	1.7	0.6	0.4	0.3	0.4	623	199	152	96	176
SWPA-4	10.3	3.8	1.7	1.2	3.6	155	55	44	25	31
SWPA	4.1	1.6	0.9	0.7	0.9	5817	1889	1550	896	1482

[a] Spring includes March–May; summer, June–August; fall, September–November; and winter, December–February.

In addition, the cumulative distributions of observed monthly temperature, rainfall, runoff, and generation are illustrated in Appendix D for each of the Southwestern assessment areas. On the graphs in Appendix D, solid black lines represent the distribution curves across the entire year, dashed green lines represent the spring months, dashed red lines the summer months, dashed black lines the fall months, and dotted blue lines the winter months.

The seasonal variability is similar in SWPA-1, SWPA-2, and SWPA-3, in which spring and summer precipitation are the greatest. However, the higher summer precipitation is offset by higher evaporation and results in far less runoff and generation than spring. The hydrologic characteristics of SWPA-4 are slightly different. Winter, spring, and fall precipitation are similar and only slightly higher than in summer. Again, because of higher summer and fall evaporation, spring and winter boast the highest runoff.

5.2.2 Correlations Between Precipitation, Runoff, and Generation

It is known that annual hydropower generation may fluctuate to a large degree, and this poses a major challenge to both water management and PMA power contracting. This variation is mainly due to hydrologic variability, which is jointly influenced by precipitation, runoff, streamflow, soil moisture, groundwater recharge, dam regulation, domestic/industrial water usage, vegetation, and urbanization. Given the complexity of the entire hydrologic system, a statistics-based risk assessment framework is required. However, a nationally consistent assessment approach has not been available to quantify the hydrologic sensitivity to hydropower generation. To understand how the major hydrologic variables (i.e., precipitation and runoff) affect hydropower generation, a comparison was performed based on the annual time-series of precipitation, runoff, and federal hydropower generation. The predictive regression models with uncertainty bounds are constructed following the analysis.

Generally speaking, a positively correlated linear pattern was observed between both precipitation-generation and runoff-generation. The scatter plots are illustrated in Figure 5-2 for precipitation-generation, and Figure 5-3 for runoff-generation. A linear fitting was performed and illustrated for each area, along with the corresponding 95% regression CI. To assist interpretation, the correlation coefficients (ρ) are also shown, with one indicating fully correlated (strongest linear relationship) and zero being uncorrelated (weakest linear relationship). Since the power generating facility and operation scheme changed with time, the regression was performed only on the latest 20 years of data (i.e., water years 1989 to 2008).

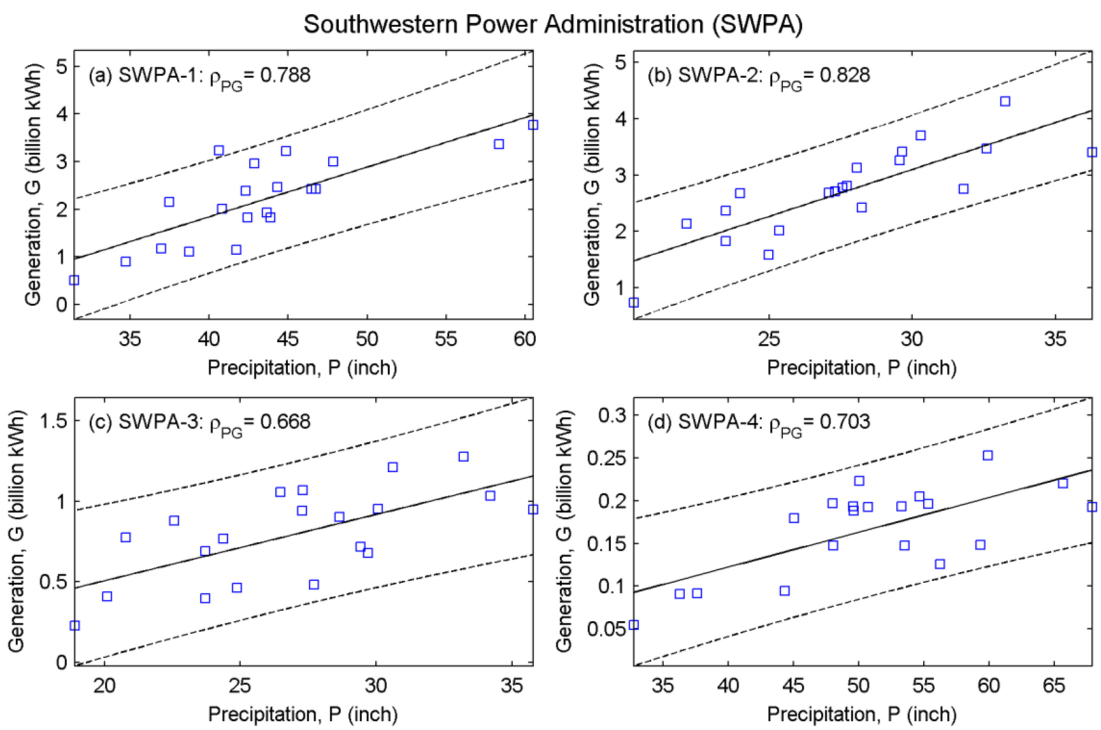

Figure 5-2. Regression between precipitation and generation for Southwestern areas.

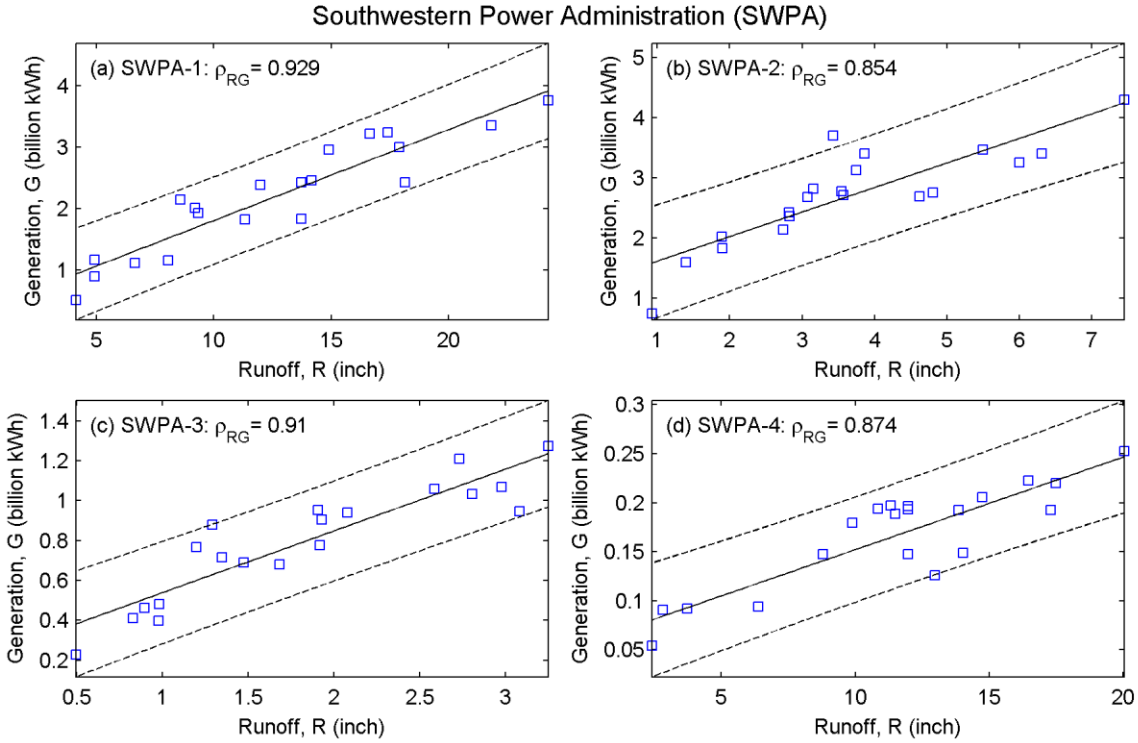

Figure 5-3. Regression between runoff and generation for Southwestern areas.

In the four Southwestern areas, correlation coefficients between precipitation and generation (ρ_{PG}) range from 0.668 to 0.828 with the highest correlation in SWPA-2 and the lowest in SWPA-3. The correlation coefficients between runoff and generation (ρ_{RG}) are much higher, ranging from 0.856 to 0.93, with the highest correlation in SWPA-1 and the lowest in SWPA-2. The width of the uncertainty bounds can be seen as another indicator showing how strong the relationship is. A narrow uncertainty bound suggests the higher confidence of a prediction model. For SWPA-1, both correlations between precipitation and generation and runoff and generation are high. The correlation coefficient ρ_{PG} between precipitation and generation is 0.788, and the 95% CI uncertainty bound is around 1.2 billion kWh. The relationship between runoff and generation is even stronger, with ρ_{RG} being 0.929 and the CI bound around 0.7 billion kWh. It indicates that while there are many factors that may affect hydropower generation, the dominant variable is runoff, which controls the amount of water available for hydropower generation. The strong relationship supports evaluating hydropower variability from simulated annual runoff directly. Similar results can be found in SWPA-2. In SWPA-2, the correlation coefficient ρ_{PG} between precipitation and generation is 0.828 with a 1 billion kWh CI bound. The relationship between runoff and generation is slightly stronger, with ρ_{RG} being 0.854 and the CI bound again around 1 billion kWh.

The difference between precipitation-generation and runoff-generation is larger in SWPA-3. The correlation coefficient ρ_{PG} between precipitation and generation is 0.668 with a 0.5 billion kWh CI bound. The relationship between runoff and generation is much stronger, with ρ_{RG} being 0.91 and CI bound around 0.25 billion kWh. In SWPA-4, the correlation coefficient ρ_{PG} between precipitation and generation is 0.703 with a 0.08 billion kWh CI bound. The relationship between runoff and generation is stronger, with ρ_{RG} being 0.874 and the CI bound around 0.06 billion kWh.

5.3 FUTURE CLIMATE PROJECTIONS FOR SOUTHWESTERN

The four Southwestern areas assessed in the 9505 Assessment make up a mainly contiguous area in the south-central United States (Figure 5-1). Far fewer regional climate assessment studies have been conducted for this general region of the United States than for other regions. The climate assessment of Karl et al. (2009) includes the Southwestern region as part of the entire Great Plains region and does not relate historical climate details strictly for this southern region; however, analysis of NCDC data from its "South" region states (KS, OK, TX, AR, LA, MS; Vose, 2010) allows characterization of the historical temperature regime. Average annual temperature over the region has increased by about 0.9°F over the period 1901–2010; but, as in many areas of the United States, changes include strong warming from the early 1900s through about 1940, followed by a general cooling through the 1970s and a renewed strong warming through the end of the 20th century (rate of about +0.45°F per decade).

The Southwestern region is characterized by a strong precipitation gradient from west to east, with mean annual precipitation of less than 50 cm (~20 in.) in the west, but approaching 125 cm (~50 in.) in the east (Karl et al., 2009). The region also experiences large interannual variability and occasional severe drought (especially evident in the 1930s and 1950s). In general, there has been an overall increase in precipitation on the century scale (NCDC, 2011; Lettenmaier et al., 2008).

5.3.1 9505 Assessment Climate Projections

The 9505 results are presented first in this section because they provide a consistent set of methods that can support inter-regional comparisons, as required. From the 9505 ensemble runs, projections of mean annual, spring, summer, fall, and winter air temperature, precipitation, and runoff changes for the near-term (2010–2024) and mid-term periods (2025–2039) were produced for each of the four Southwestern assessment areas. Comparisons were made with the baseline period (1960–1999). Projections are illustrated in Figure 5-4, showing the minimum, median, and maximum changes derived from the five 9505 ensemble members. For ease of reference, we refer here generally to approximate averages of the median changes over all four watersheds (SWPA-1 – SWPA-4). The detailed cumulative distributions of observed and simulated temperature, rainfall, and runoff are illustrated in Appendix E for each of the Southwestern assessment areas. The maps of projected runoff are shown in Appendix F for the visualization of spatial variability.

Mean annual temperature for the Southwestern region is projected to increase by approximately 2.0 and 3.0°F for the near-term and mid-term, respectively, compared with the baseline period (left column in Figure 5-4). The mid-term period change is the cumulative change, representing additional warming of about 1.0°F after the near-term. The amount of summer warming is projected to exceed that of all other seasons over both periods (on the order of 3.0–4.0°F in the latter period). The 9505 results show a consistent pattern of annual and summer warming plus, to a somewhat lesser extent, winter warming.

The projected change in precipitation in the Southwestern region is limited to fewer seasons than the change in temperature (middle column in Figure 5-4). The projected changes for precipitation in Figure 5-4 are in percentages relative to the 1960–1999 baseline. Ensemble members project little change overall in mean annual precipitation; but summer changes show a clear decreasing trend, especially over 2025–2039, and spring changes show a weaker increasing trend. However, it should be noted that for the SWPA-3 and SWPA-4 areas, the spread of the ensemble members is especially large in the mid-term, which indicates high model uncertainty. Nonetheless, the uniformly negative projections of summer precipitation over the mid-term period for the three larger, contiguous assessment areas in the Southwestern region (SWPA-1 – SWPA-3) are a strong and important trend.

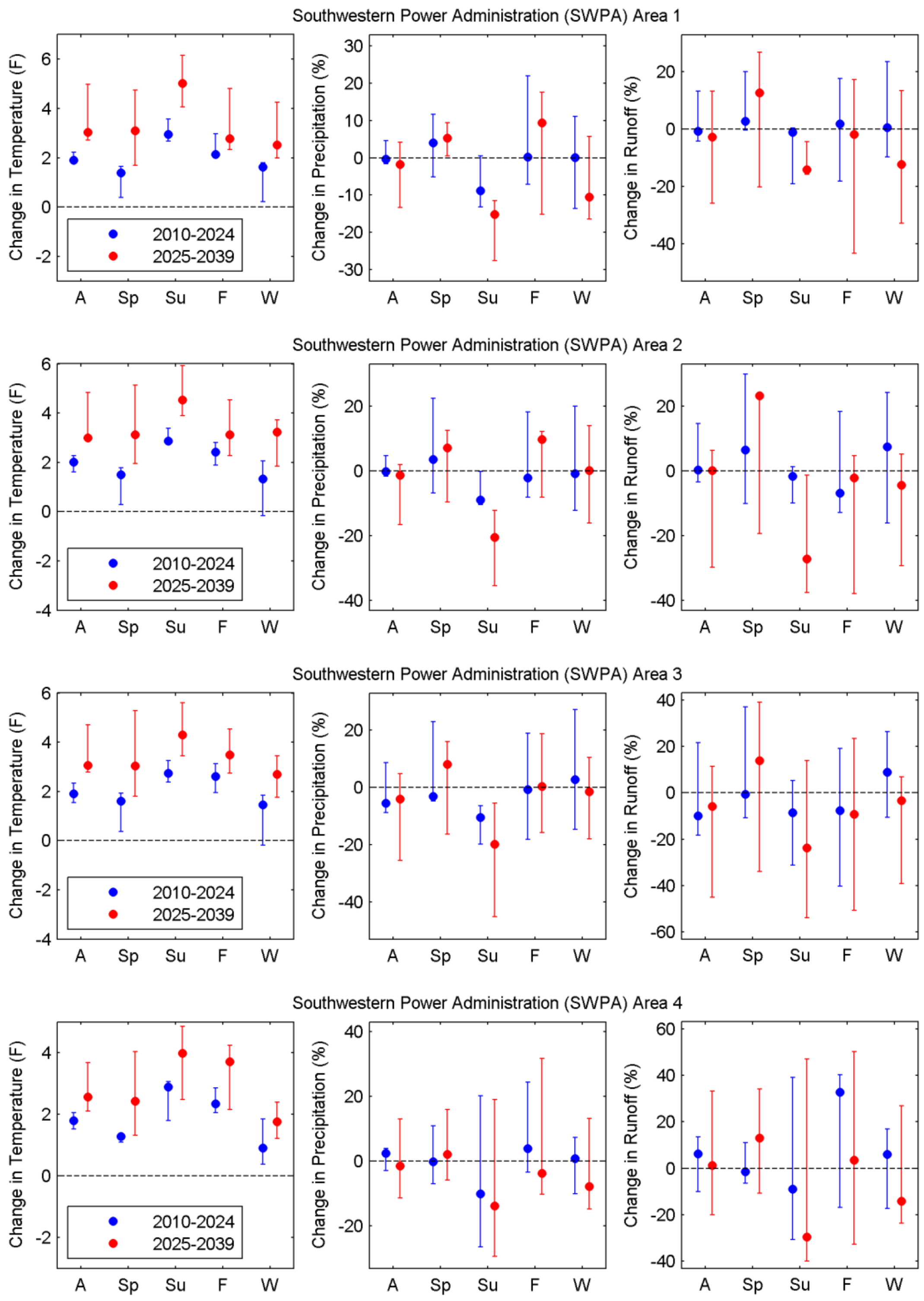

Figure 5-4. Projected change of mean annual and seasonal values of temperature (left column), precipitation (middle column), and runoff (right column) in the Southwestern region, relative to the baseline period of observed climate. The dashed line at zero is based on the mean from 1960 to 1999; circles are the mean of the median ensemble member; and the range plotted around each circle extends from the highest to the lowest ensemble member.

The 9505 results show more potential for seasonal change in runoff than in precipitation in the Southwestern region. However the spread among the 9505 ensemble members is generally quite large in this region, especially for individual seasons (right column in Figure 5-4). Some fairly consistent features in Figure 5-4 include negative changes in summer, fall, and winter median values of runoff and positive changes in spring median values of runoff in the mid-term. As with projected changes in precipitation, the spread in runoff among ensemble members for the SWPA-3 and -4 areas is extremely large.

The projected runoff changes drive changes in the frequency of water year types (Figure 5-5). Water year types are defined by annual runoff values for the baseline period. Annual runoff values of less than the lower 20% quantile during the baseline period are designated as dry years, and values greater than the upper 80% quantile are designated as wet years. The near-term shows little projected change; whereas the readily apparent mid-term changes largely correlate with projections of precipitation, with more frequent dry years and less frequent wet years, especially over the SWPA-1 – SWPA-3 areas.

Additional extremes-related statistics are shown in Table 5-4, where 10 year return level quantiles of seasonal low runoff are presented for both baseline and future projection periods. The 10 year low runoff indicates, statistically, the amount of low flow that may occur every 10 years on average. While the low-runoff quantiles generally increase in the near-term, nearly all quantiles become smaller in the mid-term.

The patterns of change in low-flow periods are consistent with Figure 5-5. Although short-duration wet extremes are not analyzed in this assessment, a recent study (Kao and Ganguly, 2011) suggested that there could be more intense and frequent precipitation extremes as observed in meteorological reanalysis datasets and projected by GCMs. It suggests the possibility of more frequent flood events and may increase the difficulty of water management for hydropower operation.

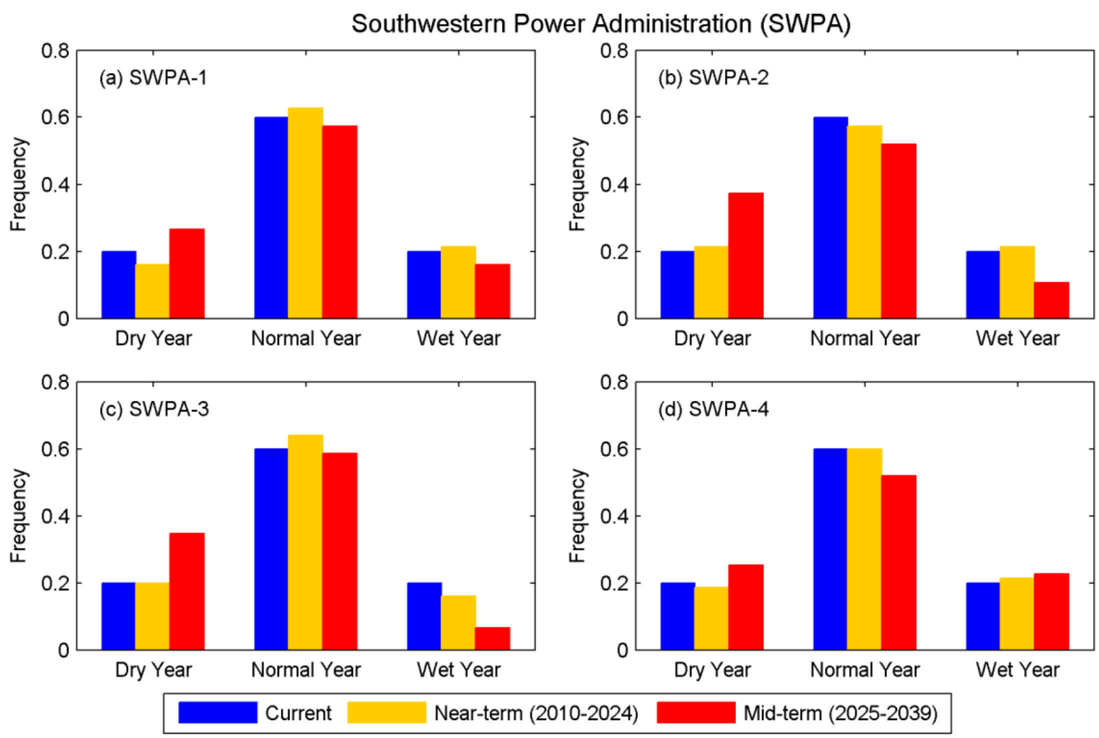

Figure 5-5. Projected frequency of water year type in the Southwestern region, based on the 9505-simulated runoff. Dry, normal, and wet water years are defined by the lower 20%, middle 60%, and upper 20%, respectively, from the 1960–1999 baseline period; these reference values are designated with blue bars to left of each group.

Table 5-4. The 10-year return level quantiles of seasonal low-runoff in the Southwestern region.

	10-year low runoff (inches/season), 1960–1999 baseline simulation			
	Spring (Mar–May)	**Summer (Jun–Aug)**	**Fall (Sep–Nov)**	**Winter (Dec–Feb)**
SWPA-1	1.78	1.20	0.64	0.84
SWPA-2	0.46	0.28	0.12	0.18
SWPA-3	0.25	0.12	0.12	0.12
SWPA-4	0.79	0.30	0.17	0.61
	10-year low runoff (inches/season), 2010–2024 future projection and percent change from baseline[a]			
	Spring (Mar–May)	**Summer (Jun–Aug)**	**Fall (Sep–Nov)**	**Winter (Dec–Feb)**
SWPA-1	2.25 (26%)	1.32 (9%)	0.75 (16%)	0.63 (−24%)
SWPA-2	0.51 (11%)	0.30 (8%)	0.09 (−23%)	0.14 (−24%)
SWPA-3	0.23 (−7%)	0.14 (18%)	0.09 (−25%)	0.13 (6%)
SWPA-4	0.96 (22%)	0.30 (0%)	0.31 (77%)	0.76 (24%)
	10-year low runoff (inches/season), 2025–2039 future projection and percent change from baseline[a]			
	Spring (Mar–May)	**Summer (Jun–Aug)**	**Fall (Sep–Nov)**	**Winter (Dec–Feb)**
SWPA-1	1.44 (−19%)	1.05 (−13%)	0.47 (−27%)	0.92 (10%)
SWPA-2	0.42 (−8%)	0.21 (−24%)	0.09 (−22%)	0.17 (−8%)
SWPA-3	0.23 (−6%)	0.09 (−28%)	0.09 (−29%)	0.11 (−10%)
SWPA-4	0.90 (14%)	0.27 (−10%)	0.15 (−13%)	0.58 (−5%)

[a] The percentage indicates the relative change comparing to baseline.

5.3.2 Other Climate Studies in the Southwestern Region

These 9505 Assessment projections of temperature, precipitation, and runoff for the Southwestern region across 2010–2039 cannot be directly compared with projections from other available studies because of several factors, such as differences in spatial domain, differences in GHG emissions scenarios in the models, the different span of baseline and projection periods, and the fact that the output has been statistically bias-corrected. Nonetheless, some qualitative statements and comparisons between this assessment and other studies can be made.

Karl et al. (2009) used the WCRP CMIP3 multi-model dataset (Meehl et al., 2007), combined with the statistical downscaling techniques of Wood et al. (2002), to make projections for six large regions of the contiguous United States. The southern portion of their “Great Plains” region largely encompasses the four Southwestern assessment areas. They provided projections of changes in temperature for 2020, 2050, and 2090 using the lower-emissions (B1) and higher-emissions (A2) scenarios (which essentially bracket the medium-emissions A1B scenario used in the 9505 Assessment). Their median projections of changes in temperature over the entire Great Plains region are approximately 2.5°F for 2020 and 4.0°F for 2050, a bit higher than the 9505 Assessment projections of 2.0°F and 3.0°F for the near-term and mid-term periods, just for the Southwestern region. (The 9505 Assessment’s mid-term period is not directly comparable with Karl et al.’s 2050 projection.) The comparison of their projected 2020 change in temperature (2.5°F) with the 9505 Assessment projected change over 2010–2025 (2.0°F) gains context through an indication of greater warming in the central and northern Great Plains compared with the

South, which includes the Southwestern region. In addition, Karl et al. projections of larger increases in summer versus winter temperature over the southern Great Plains were consistent with the 9505 Assessment seasonal projections for the Southwestern region. Only qualitative comparisons of projections in precipitation between their study and the 9505 Assessment can be made, as their study simply states that future conditions in the southern Great Plains are expected to become drier. The 9505 Assessment projections show only consistent decreases in precipitation during summers over the Southwestern region, which drive only a slight decreasing projection of annual precipitation.

There has been very little work pertaining to projecting changes in runoff over the Southwestern region. A recent study that addresses this issue to some extent is Reclamation (2011b), which analyzed model output from the CMIP3 with three emissions scenarios (A1B, B1, and A2) to project changes in temperature, precipitation, runoff, and other variables for about a dozen major western watersheds. The study employed the BCSD technique of Wood et al. (2002) to generate downscaled translations of 112 CMIP3 projections. It noted that these projections are generally not dependent on the particular emission scenario until near the middle of the 21st century. Since the 9505 Assessment uses the A1B scenario (a midrange forcing scenario between B1 and A2) and employs a bias-corrected downscaling approach, it can be viewed as essentially a middle-ground approach with respect to Reclamation (2011b). Although Reclamation (2011b) does not give detailed hydroclimate projections for the four Southwestern assessment areas (they are not classified as Western watersheds), it presents ensemble-median projected changes in mean annual runoff at the 154 USGS Hydroclimatic Data Network stations (Slack et al., 1993) over roughly the western half of the United States. These include several stations in the Arkansas and the Red and Brazos basins. Reclamation's 2020s projected changes (with respect to the 1990s), while having magnitudes of less than 10%, are uniformly negative, generally consistent with 9505 Assessment projections for SWPA-2 and -3 areas (see Figure 5-4). In addition, the work of Milly et al. (2005)—reproduced in Karl et al. (2009)—used an ensemble of 12 GCMs (not combined with RCMs) to project global changes in runoff for 2041–2060 compared with a 1901–1970 baseline. The median projected changes in runoff from the ensemble show decreases similar to those cited in Reclamation (2011b), ranging from −5 to −10% over most of the Southwestern region.

NARCCAP (Mearns et al., 2009) temperature and precipitation projections can also be generally compared with the 9505 Assessment results. NARCCAP provides results from the CCSM3 GCM (driving GCM of the 9505 Assessment) coupled with the CRCM and MM5I regional models. An important distinction between NARCCAP and the 9505 Assessment is the GHG scenario used; NARCCAP uses A2, presumably resulting in considerably stronger forcing, especially later in the 21st century. Seasonal projections for 2041–2170 (relative to a 1971–2000 base period) are readily available from the NARCCAP website. The CCSM+CRCM projections over the Southwestern region for 2041–2070 show summer warming the most, with increases of 4.5–5.4°F, followed in magnitude by fall, spring, and winter. The NARCCAP projected seasonal changes are actually rather close to the 9505 Assessment projections for 2025–2039, and the seasonal ranks for the region as a whole are the same. Given the later 2041–2070 window and greater A2 emissions forcing in the NARCCAP model runs, the similarity between CCSM+CRCM and 9505 Assessment projections of temperature is perhaps somewhat surprising. CCSM+CRCM projections of changes in precipitation over the Southwestern region for 2041–2070 are largest in summer, ranging from −20 to −30%, a range that may be described as essentially an extension of the decreases found for 2025–2039 in the 9505 Assessment (–15 to –20%). CCSM+CRCM projections also show precipitation decreasing to a smaller degree in fall and winter; modest increases in precipitation are projected for spring. The 9505 Assessment for 2010–2039 shows little evidence of significant precipitation changes for fall, winter, and spring, but of course these projections cannot be directly compared with the later NARCCAP projection period. The CCSM+MM5I temperature and precipitation projections are similar to those of CCSM+CRCM, but the magnitude of projected summer warming over the Southwestern region is considerably less.

5.4 EFFECTS ON HYDROPOWER GENERATION IN THE SOUTHWESTERN REGION

5.4.1 Projection of Hydropower Generation

The combination of the annual runoff-generation relationship (Figure 5-3) and the projection of future runoff (Figure 5-4) allows annual hydropower generation to be projected into the future (Figure 5-6). The average simulated generation during the baseline period is computed for each of the Southwestern assessment areas, along with their corresponding projected change in the two future periods. Similar to the style in Figure 5-4, the minimum, median, and maximum of the 9505 ensemble are shown. To avoid bias embedded in the VIC modeling, the bias correction technique is performed again for the simulated annual runoff by using the USGS WaterWatch observed runoff. In Figure 5-6, the dashed line for the baseline is the mean of the simulated 1960–1999 annual generation across five ensemble members; circles are the 15 year mean for the median ensemble member; and the range plotted around each circle extends from the highest to the lowest ensemble member, as a measure of model uncertainty. The numerical results are presented in tables in Appendix H. The minimum and maximum annual hydropower generation during the simulated baseline period (1960–1999), simulated near-term period (2010–2024), simulated mid-term period (2025–2039), and observed recent 20 year period (1989–2008) are also summarized in Appendix H. Detailed cumulative distributions of observed and simulated annual generation are illustrated in Appendix I for each Southwestern assessment area.

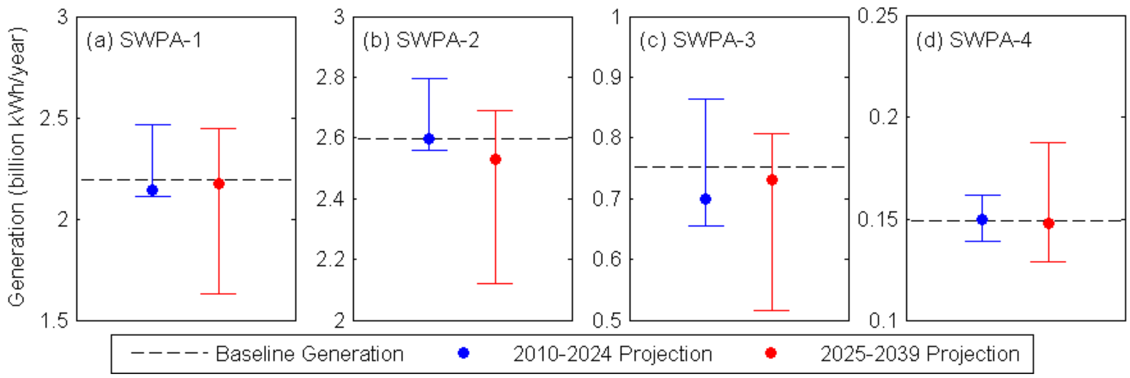

Figure 5-6. Projected annual hydropower generation in the Southwestern region, based on observed correlations with runoff. The dashed line for the baseline is the mean of simulated 1960–1999 annual generation across five ensemble members; circles are the 15 year mean for the median ensemble member; and the range plotted around each circle extends from the highest to the lowest ensemble member, as a measure of model uncertainty.

Based on the median 9505 ensemble member, a slightly decreasing trend of hydropower generation is projected in the Southwestern region. The minimum and maximum 15 year ensemble mean ranges from decreasing to increasing, suggesting a large uncertainty bound. Although the projected changes will add to the historic variability, they are mostly on a smaller scale in the Southwestern region. Therefore, the climate impact on Southwestern hydropower generation may not be significant within the assessment period. Although there could be more dry years, as suggested by simulation, the long-term change should be similar to what Southwestern has encountered in the past 20 years. However, because of the importance of rain-driven runoff and the projected change in summer precipitation and runoff in this region (Figure 5-4), summer generation from hydropower may be adversely affected by climate change in the next several decades.

5.4.2 Indirect Effects

As used in this report, "indirect effects" refers to climate-related changes to federal hydropower operations that are not included in our 9505 Assessment modeling approach and that can be expected to occur in addition to changes in precipitation and runoff. For example, some changes in air temperature are addressed in the 9505 Assessment models, but changes in air temperature will also affect energy demands and usage patterns, which may trigger changes in hydropower generation that are important in balancing power systems. Such an effect is highlighted early in the most recent NPPCC Briefing Book (NPPCC, 2010) and in the CCSP SAP 4.5 report (CCSP, 2007).

The significant increases in summer temperature projected by the 9505 Assessment over the entire Southwestern region (4.0–5.0°F by the mid-term) can be expected to increase total and peak electricity demand to accommodate increased residential cooling needs. This warming may also result in increased evaporation from reservoir surfaces, resulting in less water available for hydropower (CCSP, 2007). This effect is hard to confidently predict, however, as evaporation is not determined solely by water and air temperatures; other climate variables such as relative humidity, solar radiation, and cloudiness play important roles. At any rate, reservoirs with the largest surface areas (e.g., Eufaula and Sam Rayburn reservoirs in SWPA-2 and -4, respectively) are those potentially most sensitive to this effect.

Other likely indirect effects on hydropower include temperature-induced changes in water quality and aquatic habitat condition (Meyer et al., 1999). Possible longer periods of low summer streamflow, associated with more frequent low-runoff years (e.g., the mid-term period in Figure 5-5), could lead to increased algae growth, resulting in eutrophic conditions in reservoirs. Such effects may, depending on location and severity, require changes in hydropower project operation that reduce power production (CCSP, 2007).

Another indirect effect brought about by increasing warm-season temperatures may be increasing electricity demand and its effect on GHG mitigation activities, if renewable energy sources such as hydropower become less reliable owing to more frequent dry years (e.g., the mid-term period in Figure 5-5). Some states in the Southwestern region have established renewable portfolio standards; less hydropower generation may affect future development of other renewable capacity (e.g., solar and wind) to attain these standards. However, this influence is less likely over much of the Southwestern region, given the already considerable wind-generated electricity produced in certain states, especially Texas and Oklahoma.

5.4.3 Implications for Federal Power in the Southwestern Region

Unlike the river systems in the western United States that contain large reservoirs with the ability to store water over multiple years from snowpack runoff as well as rainfall, Southwestern's river systems do not have a significant amount of water storage and rely solely on rainfall for inflow. Roughly one-third of the 24 hydropower projects in the Southwestern region are run-of-river, and the storage projects have comparatively small power pools. Therefore, the hydropower production capability in the Southwestern region is greatly affected by changes in inflow from rainfall. For that reason, Southwestern is particularly interested in the projected potential changes in precipitation and runoff shown in the 9505 Assessment. As evidenced in Figure 5-6, Southwestern has sustained hydropower generation year after year through inflow amounts that vary to a much greater extent than the projected change due to climate variation. Although the 9505 Assessment projection does reveal the potential for impacts from climate change, particularly in the mid-term (2025–2039), it also suggests that the long-term change due to climate variation should be well within the natural variability that Southwestern already encounters. However, Southwestern must remain alert to any factors that could impact inflows, storage, or project operation and subsequently hydropower generation capability in the Southwestern region. The greatest potential to affect Southwestern's generation as revealed in the 9505 Assessment is the increased chance of drought conditions compounded by higher temperatures that would likely result in higher energy demand during the summer, which is the peak energy demand season in the Southwestern region.

Southwestern's long-term power sales contracts are based on the consideration that its electrical system relies entirely on hydropower for power generation. Those long-term contracts, typically 15 years in length, provide the customers with only 1,200 hours of energy per kilowatt of contracted capacity per year, representing a portion of their firm load requirements. To meet the contractual peaking energy requirements, energy produced at the hydropower projects must be supplemented by energy purchased on the open market, particularly in periods of below-average rainfall. These purchases are blended with the available federal hydroelectric power to allow the system to provide a beneficial, reliable product while ensuring repayment of the federal investment plus interest. System purchase requirements are affected by weather, volatile market prices, and limited availability of energy banks. In determining when to begin replacement power purchases, Southwestern uses a number of factors and computer models: non-hydro guide curve (developed using period of record system simulations) in combination with inflow trends, storage remaining, long-term weather forecasts, Palmer Drought Severity Index, season of the year, price of power, impacts on competing users, and anticipated electrical loads.

As a result of severe drought conditions experienced in the Southwestern region in 2005–2006, Southwestern worked with the presidential administration, Congress, and its customers to ensure sufficient funding mechanisms are available when needed to purchase replacement power to meet contractual obligations. Current funding mechanisms include (1) the use of receipts authority, allowing Southwestern to use receipts from the sale of hydropower to purchase replacement power; (2) alternative financing authority, including net billing, bill crediting, and/or reimbursable authority (customer advances); and (3) continuing fund authority, which allows Southwestern to request an apportionment from the Office of Management and Budget, through DOE, to use current fiscal year receipts on deposit in the US Treasury, including pre-collected receipts and funds collected through Southwestern's purchased power adder and purchased power adder adjustment.

The wide variation in rainfall, runoff, and generation historically experienced in the Southwestern region, as shown in Figure 5-6, has resulted in the development of a marketing plan for federal hydropower that already contains flexibility, contingencies, and the ability to purchase energy to firm the hydropower resources. Therefore, should climate conditions deteriorate to the level of a severe drought, Southwestern should have adequate funding mechanisms for purchasing replacement power, provided that energy and transmission are available in the region and subject to Office of Management and Budget approval for Southwestern's use of continuing fund authority.

In addition to the ability to purchase power to mitigate drought conditions, if it should become imminently unlikely that Southwestern can meet contractual power obligations because of severe long-term drought conditions, Southwestern has a contract remedy in the Uncontrollable Forces provision, which is stated as follows in Southwestern's power sales contracts:

> The Parties understand and agree that the sale of such Federal Power and Federal Energy... is contingent upon the absence of all Uncontrollable Forces and other contingencies set forth herein which may make any part or all of these quantities unavailable for sale by Southwestern.
>
> Uncontrollable Force is defined as:
>
> ... any force which is not within the control of the Party affected, including, but not limited to, failure of water supply, failure of facilities, flood, earthquake, storm, lightning, fire,

> epidemic, war, riot, civil disturbance, labor disturbance, sabotage, Congressional Act, or restraint by court of general jurisdiction, which by exercise of due diligence and foresight such Party could not reasonably have been expected to avoid.

In response to the 2005–2006 drought in the Southwestern region, before accessing the current portfolio of funding mechanisms for purchasing power, Southwestern raised the issue of the Uncontrollable Forces provision. The issue raised led to the voluntary customer deferment of peaking energy for the summer of 2006 and the contract year ending in 2007, with the agreement that the deferred volume of energy was to be repaid over the following 3 years. This action reduced the federal government's energy obligation throughout the drought. The Uncontrollable Forces provision includes "failure of water supply" specifically, which is the result of a severe long-term drought.

Southwestern continually remains aware of, and proactively responsive to, competing use demands on project storage as well as climate and hydrologic conditions that impact inflows in the Southwestern region. As all of the hydropower projects in the Southwestern region are multi-purpose projects, competing uses include flood control, water supply, navigation, fish and wildlife, both in-lake and downstream recreation, and tourism. The various uses affect the operation and available storage of each project, and all, including hydropower, depend upon inflows from rainfall. Southwestern actively participates in numerous water resource committees and work groups; participates in and reviews and comments on studies; and continuously communicates with USACE and stakeholders concerning the balance of power and nonpower uses and the availability of water, at each project and for the region as a whole. The concerns this initial 9505 Assessment and future climate change studies bring to light in the Southwestern region will continue to be reviewed and monitored in conjunction with the various other concerns that impact Southwestern's hydropower production capability and its ability to meet contract power obligations.

6. THE SOUTHEASTERN REGION

This section describes SWA Section 9505 Assessment results for the Southeastern region and the federal hydropower projects located there. The section is organized into four subsections, the first of which explains how the region was subdivided into areas of analysis. The first subsection also presents information on the region's federal hydropower system, power marketing by Southeastern, and major water management issues within the region. The second subsection describes existing hydrology and generation patterns in the region under the current climate (i.e., the baseline for comparison with climate change projections). The third subsection contains results of the climate change projection that was done for this Section 9505 Assessment, along with a literature-review comparison with climate studies by others. The fourth subsection focuses on potential changes to federal hydropower generation under the projected future climate, and possible adaptation options in response to the effects of climate change.

6.1 REGIONAL CHARACTERISTICS

The Southeastern Power Administration (Southeastern) markets hydroelectric power in ten southeastern states and southern Illinois (Figure 6-1). This region is the only eastern PMA region and contains no Reclamation projects. The 22 USACE hydropower projects in this region have a total installed capacity of 4100 MW and an average annual generation of 7.8 billion kWh (Section 6.1.2 and Appendix B). The region is subdivided into four areas of analysis, based on how Southeastern markets federal power:

- Southeastern Area 1 (SEPA-1): the Roanoke River Basin in Virginia and North Carolina
- Southeastern Area 2 (SEPA-2): the Cumberland River Basin in Kentucky and Tennessee
- Southeastern Area 3 (SEPA-3): the combination of the Savannah, upper Apalachicola, and Alabama River Basins in South Carolina, Georgia, and Alabama
- Southeastern Area 4 (SEPA-4): the lower Apalachicola and Flint River Basins in Georgia and Florida

6.1.1 Areas of Analysis

The Southeastern region is distinctly different from the other three regions considered in the 9505 Assessment because of its lower elevations, higher precipitation, and more heavily vegetated, deciduous land cover.

The first analysis area in the Southeastern region (SEPA-1) is located in the upper half of the Roanoke River Basin above the John H. Kerr project. The watershed begins on the eastern slope of Blue Ridge Mountains in southwestern Virginia and extends down into the mid-Atlantic coastal plain. The total drainage area is 7,866 mile^2, making it one of the smallest evaluated in the 9505 Assessment. Elevations range from 3,743 to 299 ft amsl with a median of about 700 ft amsl. Dominant land cover types are cropland–natural vegetation mosaic (52%), deciduous broadleaf forest (32%), and mixed forest (8%), plus minor cropland (3%).

The second analysis area (SEPA-2) includes the entire Cumberland River Basin, extending from the Appalachian Mountains westward to its confluence with the Tennessee and Ohio Rivers. The total drainage area is 17,607 mile^2. Elevations range from over 4,000 ft amsl in the eastern headwaters to 300 ft amsl at the Ohio River with a median of approximately 900 ft amsl. Land cover is a diverse mixture of deciduous broadleaf forest (39%), cropland–natural vegetation mosaic (36%), cropland (17%), and mixed forest (3%).

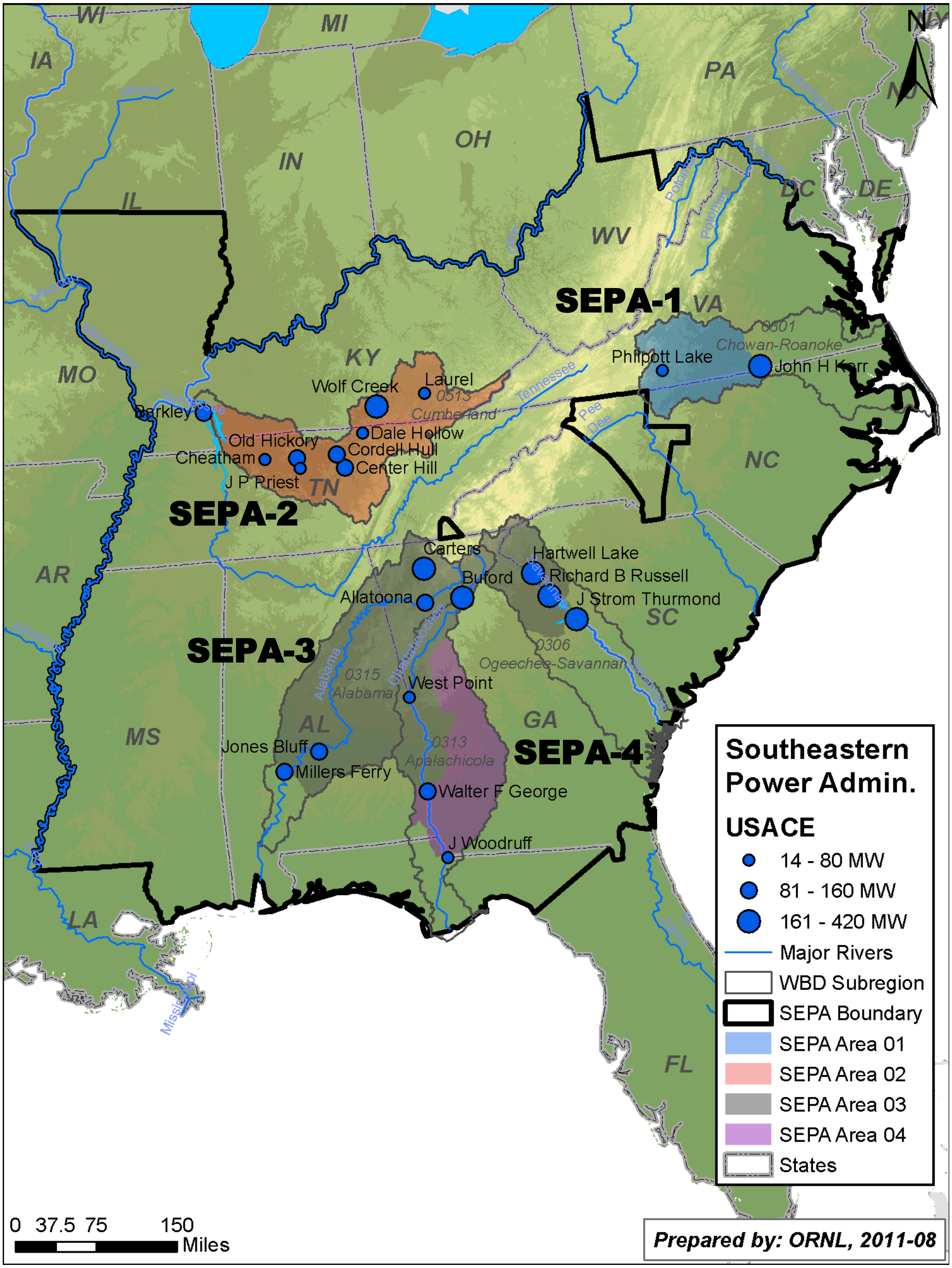

Figure 6-1. Map of the federal hydropower projects and analysis areas in the Southeastern region.

The third area of analysis in the Southeastern region (SEPA-3) covers the upper portions of three relatively large river basins, all of which have their headwaters in the southern Blue Ridge Mountains. The Savannah River flows to the Atlantic Ocean, and the Apalachicola and Alabama river systems flow to the Gulf of Mexico. The total drainage area of these three watersheds is 34,244 mile^2. Elevations range from over 5,000 ft amsl to about 40 ft amsl, from mountains in the northern end to the southern coastal plains. The median elevation of this area is 682 ft amsl. Land cover is mostly cropland–natural vegetation mosaic (42%) and mixed forest (35%), plus minor amounts of woody savanna (12%) and deciduous broadleaf forest (4%).

The fourth area (SEPA-4) is defined by one small USACE hydropower project, the J. Woodruff project located on the border of Georgia and Florida. Power from this project is marketed separately by Southeastern; therefore, it defines a distinct area on the Georgia piedmont and coastal plain. The total watershed area is 17,164 mile^2, 39% of which comes from the upper Apalachicola River that flows through the Atlanta metropolitan area and from the Flint River. Land cover is primarily cropland–natural vegetation mosaic (50%), mixed forest (20%), cropland (17%), and woody savanna (9%).

6.1.2 Federal Hydropower System

All of the federal hydropower projects in the Southeastern region are owned and operated by USACE (Table 6-1). Most of the installed capacity in the region (66%) is located at the ten projects located on the large rivers flowing out of Georgia, Alabama, and South Carolina (SEPA-3 area). The Cumberland River system accounts for most of the rest (26%) of Southeastern's power capacity. The two largest projects, in terms of capacity, in the Southeastern region are Richard B. Russell (eight units totaling 664.0 MW) and Carters (four units totaling 606.0 MW). The smallest projects are J. Percy Priest (30.0 MW) and Philpott (15 MW). Two of the USACE projects in the Southeastern region have some reversible turbines (Richard B. Russell and Carters). A complete listing of all of the federal hydropower projects in the Southeastern region can be found in Appendix B, including capacities and average annual generation for each.

Table 6-1. Hydropower distribution among the areas of analysis in the Southeastern region

Area	Major watersheds	Number of plants			Total installed capacity[a] (MW)	Average annual generation[b] (million kWh/year)
		USACE	Reclamation	Total		
SEPA-1	Roanoke	2	0	2	311	463
SEPA-2	Cumberland	9	0	9	1049	3120
SEPA-3	GA-AL-SC	10	0	10	2697	3963
SEPA-4	Jim Woodruff	1	0	1	43	237
Total		22	0	22	4100	7783

[a] Southeastern total nameplate capacity. Includes both conventional hydro and pumped storage.
[b] Southeastern average annual generation from October 1970 to September 2008 (fiscal year). Conventional hydro only.

The oldest projects in this region are the Allatoona project in SEPA-3 and the Center Hill project in SEPA-2, each with an on-line date of 1950. The newest hydropower project in the Southeastern region is the Richard B. Russell project on the upper Savannah River, which began operation in 1984. The average age of USACE hydropower projects in Southeastern's region is 35 years; hence, it shares the need for equipment modernization and refurbishment that is common to the entire federal hydropower fleet (Sale, 2011). The USACE is actively studying these needs in the Hydropower Modernization Initiative (HMI)

(MWH, 2009 and 2010). In the Cumberland system, for example, HMI studies have estimated a total need of between $344 and $472 million over the next 10 to 30 years for equipment replacement and upgrades, just for nine of the projects in the Cumberland system (MWH, 2009). If these needed investments are not made, the USACE HMI studies predict that unplanned outages, O&M costs, and equipment upgrade costs will all increase over the next several decades.

6.1.3 Multi-Purpose Water Management Issues

The Southeastern region has some of the same water resources management challenges that occur in other parts of the United States. Growing demand for municipal and industrial water supply, especially in the rapidly growing Atlanta area of northern Georgia, is the most pressing issue (e.g., Magnuson, 2009). Recreational and environmental water uses are also causing changes in how surface water is managed (e.g., Whisnant et al., 2009). Reallocation of water storage to all of these competing water uses is having a gradual but increasingly adverse impact on federal hydropower production.

A persistent, unresolved controversy over reallocation of water storage in USACE reservoirs has been going on for more than two decades in the Georgia-Alabama-Florida region, where the Atlanta metropolitan area continues to expand and demand more water for municipal and industrial uses. Two river systems are involved: the Alabama-Coosa-Tallapoosa (ACT) River Basin, which drains to the southwest from Atlanta through Georgia and Alabama, and the Apalachicola-Chattahoochee-Flint (ACF) River Basin, which drains to the south from Atlanta through Georgia, Alabama, and Florida. Twelve federal agencies, three state governments, and numerous nongovernmental interest groups have been involved in these negotiations. In 1997, two river basin compacts were established to find water allocation formulas, but these compacts fell apart in 2003 because of the failure to find an acceptable formula. This failure represented a significant lost opportunity to avoid future controversy.

Two USACE hydropower projects and reservoirs are involved in the ACT-ACF systems: Lake Lanier, above Buford Dam in the upper part of the ACF Basin, and Lake Allatoona in the ACT Basin. These projects were originally authorized in the 1950s for flood control, hydropower, and navigation but not for water supply (Magnuson, 2009). Hydropower revenues paid for most project costs (88% in the case of Buford Dam). Both river basins are potential sources of new municipal and industrial water supplies for the Atlanta area. Over the last 60 years, water supply uses of these water systems have been allowed to gradually increase under short-term "interim" water contracts between USACE and local municipalities and water utilities. For example, in the cases of Lake Lanier and the Chattahoochee River at Atlanta, water supply withdrawals have grown, respectively, from 10 and 230 million gallons per day (mgd) in the mid-1970s to 141 and 377 mgd now. These increases in water supply withdrawals have been supported by a gradual de facto reallocation of storage in the conservation pool of Lake Lanier from hydropower uses to water supply. The USACE cooperated in meeting local economic development needs by permitting these new uses, but it never requested authorization from Congress, as required under the Water Supply Act.

The US District Court in Jacksonville ruled that water supply was not an authorized use of Lake Lanier; that new water supply uses did seriously affect hydropower, which was one of the authorized uses; and the reallocation could not occur unless Congress authorized it (Magnuson, 2009). The judge in the case, Paul A. Magnuson, gave USACE and water users in the region 3 years to obtain new Congressional authorization. If it is not obtained, water management is to revert to the withdrawal levels that were occurring in the mid-1970s. Even Judge Magnuson admitted that such a loss in water supply for this region would have "draconian results." But he also firmly stated that "USACE's failure to seek Congressional authorization for the changes it has wrought in the operation of Buford Dam and Lake Lanier is an abuse of discretion and contrary to the clear intent of the Water Supply Act." Resolution of the ACT-ACF water disputes will continue to be the most complex issue and the hardest to solve because of the number and diversity of interests involved. One of the major unresolved issues is how to evaluate the tradeoffs between lost hydropower generation and water supply benefits and how to equitably compensate hydropower customers for the services they will no longer have. Another unresolved issue is how to protect downstream aquatic ecosystems that are adversely affected by consumptive water withdrawals upstream.

Another case representative of the challenges facing hydropower in the Southeast is the ecosystem restoration initiative occurring at the John H. Kerr Dam on the Roanoke River in Virginia and North Carolina (Whisnant et al., 2009). At that project, a Section 216 study was conducted to review dam operations and make recommendations to Congress as to how ecological conditions downstream of the dam can be improved. From an ecosystem restoration point of view, the primary driver for the study is the fact that the dam's flood control operations have significantly changed the frequency and magnitude of high flows that are ecologically important in maintaining floodplain forests downstream of the dam. The hydropower plant at Kerr Dam also operates in a peaking mode. Peaking releases maximize the monetary value of hydropower but also cause rapid swings between high and low flows in downstream aquatic habitats, which may damage fish resources. Alternative operating procedures are being sought that will stabilize short-term fluctuations in dam releases and restore both flood plain hydrology and habitat conditions for fish.

The operational changes needed to restore downstream ecosystems below Kerr Dam could have adverse effects on hydropower generation and associated revenues.

In addition to Kerr Dam, there are two other downstream hydropower plants on the main stem of the Roanoke River, Gaston Dam and Roanoke Rapids Dam, which are owned and operated by Dominion Power. Changes in releases from Kerr Dam would affect flows and generation at the two downstream Dominion projects. Power generated at Kerr Dam is marketed to federal preference customers by SEPA at rates based on federal costs of operation, and they are significantly below market values in the regional transmission area into which that power is sold. Less peaking generation at Kerr Dam would mean that SEPA and its preference customers would have to replace cheap existing power with more expensive, open-market alternatives. Also, higher seasonal releases from Kerr Dam, designed to restore floodplain hydrology, would exceed the maximum generation at Roanoke Rapids, resulting in spillage there that has no energy value. To date, the most balanced alternative for ecosystem and energy objectives is identified as Alternative 6B (Whisnant et al., 2009). Depending on water year type and electricity pricing assumptions, that alternative could result in up to 6% less hydropower generation and $1.1 million per year in revenue reductions to combined power customers (Whisnant et al., 2009). While not large, these tradeoffs are enough to cause opposition between energy and environmental interests.

The recommendations from the Kerr 216 Study will advise USACE and ultimately Congress regarding the feasibility of modifying the structures or their operation and regarding improving the quality of the environment in the overall public interest. Information developed during the study may become the basis for changes under existing or new authorities. These new authorities could be implemented by Congress or by the legislatures of the sponsors, the State of North Carolina and the Commonwealth of Virginia. The study provides the opportunity to integrate and assess different viewpoints from interested parties to achieve common beneficial goals.

6.1.4 Power Marketing by Southeastern

Southeastern, created in 1950 by the Secretary of Interior, sells power to 489 preference customers in 11 states. Capacity allocated to customers in FY 2010 was 2417 MW. Its customer body includes 290 public bodies, 198 electric cooperatives, and 1 investor-owned utility, Florida Power Corporation (Southeastern, 2009). Southeastern is the only PMA that does not own any transmission assets. It operates four power systems:[7]

- Georgia-Alabama-South Carolina system (ten projects). The Russell and Carters pump storage projects are included in this system.
- Kerr-Philpot system (two projects).
- Cumberland system (nine projects).
- Jim Woodruff system (one project).

In FY 2010, Southeastern's power sales amounted to $255M. Power purchases were $14M. Southeastern's debt service ratio for FYs 2006–2009 was below 1 because of adverse water conditions (i.e., cash flow was not enough to cover O&M expenses plus principal and interest payments on outstanding debt) (Southeastern, 2009).

Southeastern's rates are reviewed annually and revised on a 5 year interval or less, as is appropriate under the terms of Southeastern's current contracts and DOE Order RA 6120.2.

Southeastern's rate schedules are approved until September 2013 for the Cumberland System, until September 2014 for the Jim Woodruff System, and until September 2015 for the Georgia-Alabama-South Carolina and Kerr-Philpott systems. Customers in the Georgia-Alabama-South Carolina System experienced a rate increase starting in October 2010 (Federal Register, 2010d). In the Kerr-Philpott System, capacity and energy rates will not remain constant over the interim approval period. Instead, they will experience an annual adjustment each April 1 to account for additions to plant-in-service during the previous fiscal year that were not included in the most recent power repayment study (Federal Register, 2010c). In addition, there is an adjustment clause to net revenue available for repayment.

Jim Woodruff project customers saw an increase in rates in 2009 (Federal Register, 2009b). Even after the increase, its rates will be significantly lower than those for electricity purchased from alternate sources. Estimates of purchased power expenses are based on a historical average and bundled in the capacity and energy charges. Southeastern is in the process of adjusting rates in the Jim Woodruff System. The adjustment would reduce the capacity and energy rates and establish a pass-through for purchased power.

The current rate schedules for the Cumberland System are significantly different from those in other systems. Since 1993, the marketing policy for the Cumberland System has provided peaking capacity along with 1500 hours of energy annually with each kilowatt of capacity. Because of restrictions imposed by USACE on the operation of the Wolf Creek and Center Hill Projects, Southeastern cannot provide peaking capacity from these projects and has implemented an Interim Operating Plan for the Cumberland System to provide them with energy. Southeastern is in the process of adjusting the rate schedules for the Cumberland System. If approved, the proposed rates under the Interim Operating Plan would increase. Under the Interim Operating Plan, the affected customers would receive a ratable share of the energy made available by the Nashville District of USACE (Federal Register, 2008a). The rate schedules for preference customers in the other Southeastern power systems are long-term firm power sales by which the government is obligated to supply, and the customer is entitled to receive, allocated capacity and energy (Southeastern, 2010b).

Southeastern and USACE receive annual Congressional appropriations through DOE and the Department of Defense to finance their operations. The USACE also receives Congressional appropriations to finance construction of its hydroelectric projects. Southeastern is responsible for repayment, with interest, of its

[7] According to DOE Order RA6120.2, a power system is a system comprising one project or more than one project hydraulically and/or electrically integrated and therefore treated as one unit for the purpose of establishing rates.

appropriations, as well as USACE construction and operation appropriations allocated to power in Southeastern's marketing region (Southeastern, 2009). Southeastern's appropriations go toward O&M expenses, purchase power (acquisition of contractually required power purchases), and wheeling (acquisition of contractually required transmission services). Southeastern also has access to a continuing fund for emergency power purchases. However, nonroutine maintenance and rehabilitation work has not been conducted because appropriated funding to USACE has not been available, resulting in increased outage rates and decreased peak availability rates over the last decade. Under Section 212 of the Water Resources Development Act of 2000, USACE has the authority to use funds provided by Southeastern's preference customers to carry out the operation, maintenance, rehabilitation, and modernization of hydroelectric power-generating facilities. Since this law was passed, customer funding initiatives have been implemented in the Georgia-Alabama-South Carolina, Cumberland, and Kerr-Philpott Systems (Southeastern, 2009).

In recent years, rainfall amounts in the Southeastern region have been lower than average. As a result, USACE has had to implement its drought operational plans for the river basins. In FY 2010, generation was 111% of the historical average in the Georgia-Alabama-South Carolina system, 137% for the Kerr-Philpott system, 93% in the Cumberland system, and 68% in the Jim Woodruff system (Southeastern, 2009). The difference in capacity or energy between the project generation and the customer contract requirements must be purchased by Southeastern. Capacity allocations cannot be changed unless a contract is terminated.

6.2 WATER AVAILABILITY AND HYDROPOWER GENERATION

6.2.1 Observed Hydrology and Generation

The 1971–2008 average annual, spring (March, April, and May), summer (June, July, and August), fall (September, October, November), and winter (December, January, and February) temperature, precipitation, runoff, and generation are summarized in Table 6-2 for the four Southeastern assessment areas. Using drainage area as a weighting factor, the average across the entire Southeastern region is also computed. Southeastern has the highest precipitation and runoff among the four PMAs, in which the mean annual precipitation and runoff are 52.0 and 19.8 in., respectively. Although it is also the hottest region, with strong evaporation, the runoff-to-precipitation ratio (38%) is the second highest, smaller than Bonneville's (51%). Therefore, the hydrologic inputs to the Southeastern region should be fairly abundant. However, not having large reservoirs like Grand Coulee, Southeastern produces only around 10% as much hydropower as Bonneville.

In addition, the cumulative distributions of observed monthly temperature, rainfall, runoff, and generation are illustrated in Appendix D for each of the Southeastern assessment areas. On the graphs in Appendix D, solid black lines represent the distribution curves across the entire year, dashed green lines represent the spring months, dashed red lines the summer months, dashed black lines the fall months, and dotted blue lines the winter months. Note that in computing the regional average temperature, precipitation, and runoff for SEPA-4, the upstream area in SEPA-3 is used. Winter and spring runoff contributes the most to the Southeastern system. Given the high summer evaporation, winter runoff is much stronger than summer, suggesting the need for reservoir storage to meet the higher summer water use demand.

Table 6-2. Summary of the 1971-2008 average temperature, precipitation, runoff, and generation for the Southeastern assessment areas

	Temperature (F)					Precipitation (inches)				
	Annual	Spring[a]	Summer[a]	Fall[a]	Winter[a]	Annual	Spring	Summer	Fall	Winter
SEPA-1	56	56	74	58	38	45.0	11.9	12.0	11.2	9.9
SEPA-2	57	56	75	58	38	52.8	14.7	12.7	11.8	13.6
SEPA-3	61	61	77	63	45	53.7	14.4	13.1	11.5	14.7
SEPA-4	64	63	79	65	48	51.2	13.1	13.8	10.4	13.9
SEPA	60	60	77	61	43	52.0	13.9	13.0	11.3	13.8
	Runoff (inches)					**Generation (million kWh)**				
	Annual	**Spring**	**Summer**	**Fall**	**Winter**	**Annual**	**Spring**	**Summer**	**Fall**	**Winter**
SEPA-1	14.0	5.0	2.5	2.5	4.0	463	159	92	84	128
SEPA-2	22.8	8.2	3.0	2.8	8.8	3120	961	662	520	977
SEPA-3	20.6	7.4	3.4	3.1	6.7	3963	1118	915	825	1105
SEPA-4	17.7	6.1	3.2	2.7	5.7	237	63	59	55	60
SEPA	19.8	7.1	3.1	2.8	6.8	7783	2306	1724	1478	2275

[a] Spring includes March–May; Summer includes June–August; Fall includes September–November; and Winter includes December–February

6.2.2 Correlations Between Precipitation, Runoff and Generation

It is known that annual hydropower generation may fluctuate in large degree, and the variation poses a major challenge to both water management and PMA power contracting. This variation is mainly due to hydrologic variability, which is jointly influenced by precipitation, runoff, streamflow, snowmelt timing, soil moisture, groundwater recharge, dam regulation, domestic/industrial water usage, vegetation, and urbanization. Given the complexity of the entire hydrologic system, a statistics-based risk assessment framework is required. However, a nationally consistent assessment approach has not been available to quantify the hydrologic sensitivity to hydropower generation. To understand how the major hydrologic variables (i.e., precipitation and runoff) affect hydropower generation, a comparison was performed based on the annual time series of precipitation, runoff, and federal hydropower generation. The predictive regression models with uncertainty bounds are constructed following the analysis.

Generally speaking, a positively correlated linear pattern was observed between both precipitation-generation and runoff-generation. The scatter plots are illustrated in Figure 6-2 for precipitation-generation, and Figure 6-3 for runoff-generation. A linear fitting was performed and illustrated for each area, along with the corresponding 95% regression CI. To assist interpretation, the correlation coefficients (ρ) are also shown, with 1 indicating fully correlated (strongest linear relationship) and 0 being uncorrelated (weakest linear relationship). Since the power generating facility and operation scheme changed with time, the regression was performed only on the latest 20 years of data (i.e., water years 1989 to 2008).

In the four Southeastern areas, correlation coefficients between precipitation and generation (ρ_{PG}) range from 0.371 to 0.79 with the highest correlation in the Cumberland River Basin (SEPA-2) and the lowest in the Jim Woodruff project (SEPA-4). The correlation coefficients between runoff and generation (ρ_{RG}) are much higher, ranging from 0.525 to 0.992, with the highest correlation in SEPA-1 and the lowest again in SEPA-4. The width of the uncertainty bounds can be seen as another indicator showing how strong the relationship is. A narrow uncertainty bound suggests the higher confidence of a prediction model.

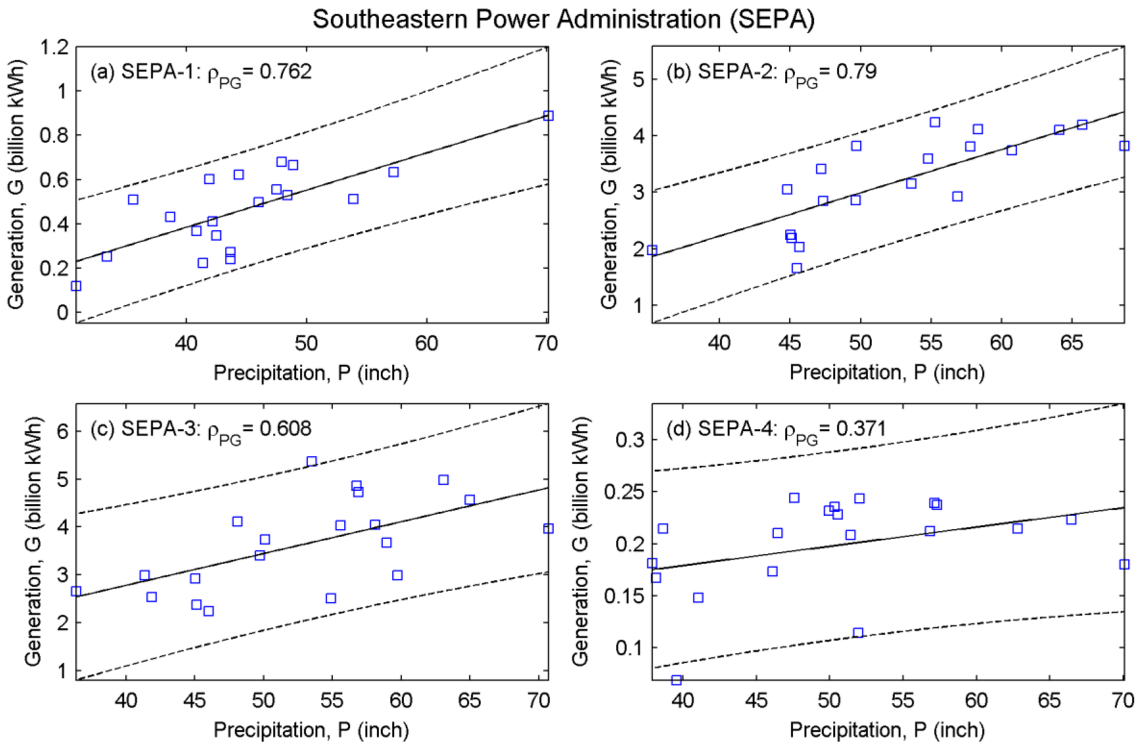

Figure 6-2. Regression between precipitation and generation for Southeastern areas.

For SEPA-1, the correlation between runoff and generation is much higher than between precipitation and generation. The correlation coefficient ρ_{PG} between precipitation and generation is 0.762, and the 95% CI uncertainty bound is around 0.3 billion kWh. The relationship between runoff and generation is very strong with ρ_{PG} being 0.992 and the CI bound around 0.05 billion kWh. It indicates that although there are many factors that may affect hydropower generation, the dominant variable is runoff, which controls the amount of water available for hydropower generation. The strong relationship supports evaluating hydropower variability from simulated annual runoff directly.

Similar results can be found for SEPA-2 and SEPA-3. For SEPA-2, the correlation coefficient ρ_{PG} between precipitation and generation is 0.79 with a 1.2 billion kWh CI bound. The relationship between runoff and generation is again stronger with ρ_{RG} being 0.912 and the CI bound around 0.8 billion kWh. For SEPA-3, the correlation coefficient ρ_{PG} between precipitation and generation is 0.608 with a 1.7 billion kWh CI bound. The relationship between runoff and generation is much stronger with ρ_{RG} being 0.903 and the CI bound around 0.8 billion kWh. The weakest relationship is observed in SEPA-4, in which both correlations are 0.371 and 0.525 with a 0.09 billion kWh uncertainty bound. Note that SEPA-4 contains only one smaller project, and nonhydrologic factors may affect more than its hydropower generation.

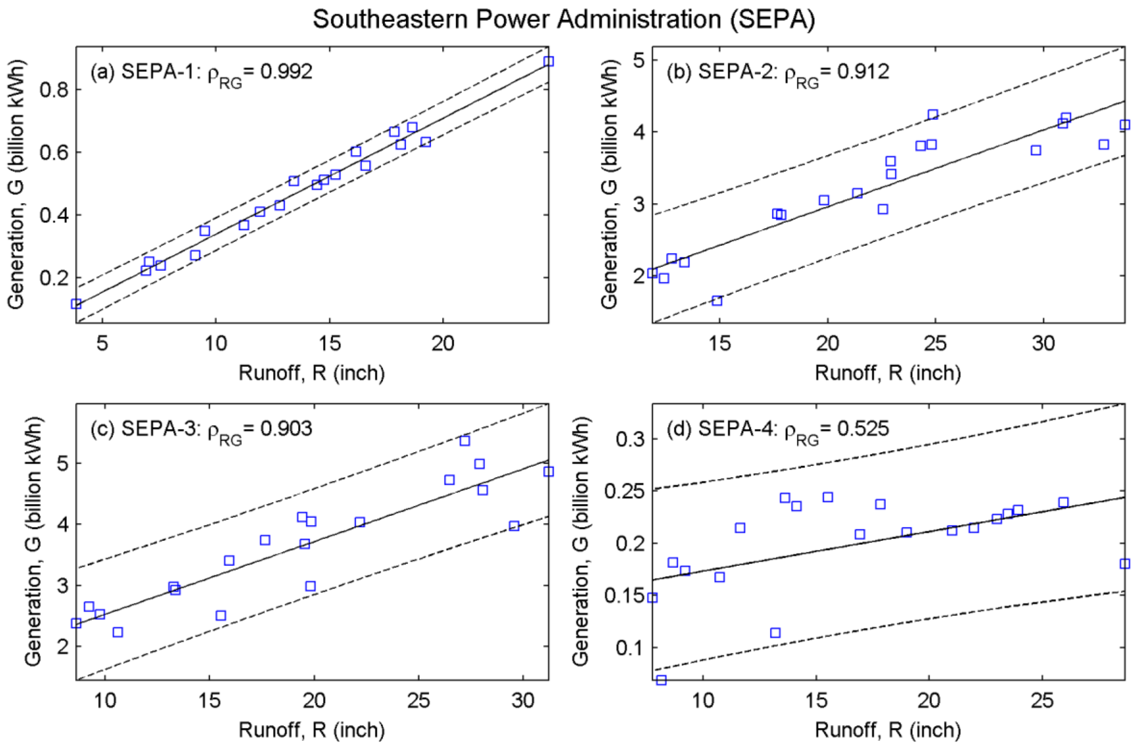

Figure 6-3. Regression between runoff and generation for Southeastern areas.

6.3 FUTURE CLIMATE PROJECTIONS FOR SOUTHEASTERN

The Southeastern region is made up of assessment areas in three discontinuous areas (Figure 6-4). Far fewer regional climate projection studies have been conducted for this general region of the United States than for the others examined in the 9505 Assessment, especially compared with the western states. However, as with other regions, century- and decadal-scale climate changes in the Southeast have been analyzed in detail. Karl et al. (2009) discusses changes for the Southeast United States, defined as a region stretching from the Texas Gulf Coast eastward across all other Gulf Coast states and the southeast Atlantic Coast states, and bordered in the north by Arkansas, Kentucky, and Virginia. Their analysis shows that the average annual temperature of the Southeast has not changed significantly over the period 1901–2008; however, since 1970, it has risen by about 1.8°F (about 0.45°F per decade) with the largest increases over the winter months (about 2.7°F). Analysis of NCDC data (Vose, 2010) for its somewhat different "Southeast" region (roughly the eastern half of the Karl et al. [2009] region: Florida, Alabama, Georgia, South Carolina, North Carolina, and Virginia) also indicates little century-scale warming but a somewhat smaller, but still significant, change since 1970 of about 1.25°F.

Karl et al. (2009) also provides spatial information on Southeast precipitation changes over 1901–2007. Average autumn precipitation over most of the Southeast has increased significantly (about 30%, with the exception of Florida and southern Georgia), but summer and winter precipitation have both decreased significantly over the eastern part of the region. Decreases are on the order of 10% for the GA-AL-SC and Jim Woodruff watersheds (SEPA-3 and 4), and 15–25% in the vicinity of the Roanoke watershed (SEPA-1). Using data from NCDC's US Historical Climatology Network (USHCN, 2009), Karl et al. found that from 1958 to 2008, mean annual precipitation decreased over most states in the Southeast (NC, SC, GA, AL, and FL); the largest decreases of 10–15% covered all of South Carolina and most of

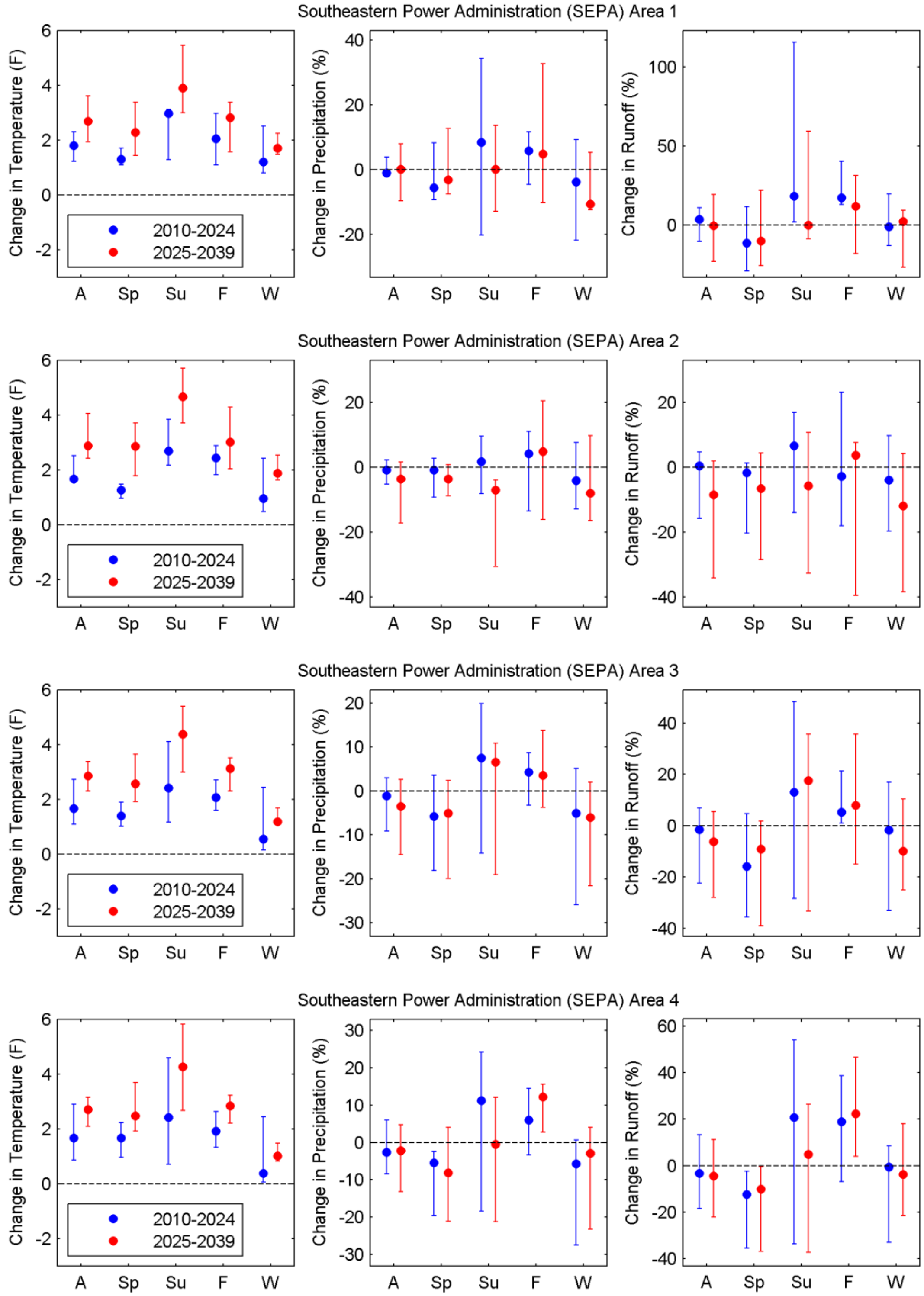

Figure 6-4. Projected change of mean annual and seasonal values of temperature (left column), precipitation (middle column), and runoff (right column) in the Southeastern region relative to the baseline period of observed climate. The dashed line at zero is based on the mean from 1960 to 1999; circles are the mean of the median ensemble member; and the range plotted around each circle extends from the highest to the lowest ensemble member.

Georgia and Florida. In addition, for that study's Southeast region as a whole, decreases in spring precipitation of almost 30% over 1970–2008 were reported. No region-wide significant trends in runoff have been observed for the Southeast, although large interannual variations in runoff are common.

6.3.1 9505 Assessment Climate Projections

Projections of the future Southeastern regional climate using the 9505 Assessment methods are described first, because they provide a consistent assessment approach for use in inter-regional comparisons. Using the 9505 ensemble runs, projections of mean annual, spring, summer, fall, and winter air temperature, precipitation, and runoff changes for the near-term (2010–2024) and mid-term (2025–2039) periods were produced for each of the four major Southeastern assessment areas. The future projections are illustrated in Figure 6-4, showing the minimum, median, and maximum changes derived from the five 9505 ensemble members. For ease of reference we refer here generally to approximate averages of the median changes over all four watersheds (SEPA-1 – SEPA-4). The detailed cumulative distributions of observed and simulated temperature, rainfall, and runoff are illustrated in Appendix E for each of the Southeastern assessment areas. The maps of projected runoff are shown in Appendix F for the visualization of spatial variability.

Mean annual temperature for the Southeastern region is projected to increase by about 1.8°F and 2.7°F for the near-term and mid-term periods, respectively, compared with the baseline period (left column in Figure 6-4). The mid-term period change is the cumulative change, representing an additional warming of about 0.9°F after the near-term period. Summertime warming is projected to exceed that of all other seasons over both periods (summer warming of 4.0–4.5°F in the mid-term period), followed in magnitude of warming by fall, spring, and winter. The degree of projected annual and seasonal warming is generally similar over all four Southeastern areas, as well as to other regions, although the magnitude of warming in the Southeastern region is somewhat less than other, more northern regions.

The 9505 results do not show a clear and consistent pattern of changes in precipitation over the Southeastern region for either of the future 15 year periods (middle column in Figure 6-4), compared with the temperature changes. The projected precipitation changes presented in Figure 6-4 are in percentages relative to the 1960–1999 baseline precipitation. There is little indication of change in mean annual precipitation, and the range of ensemble members spans the reference line. The strongest indicators of change in precipitation are in drier spring and winter seasons in all areas, but those are balanced by increased summer and fall precipitation, especially in SEPA-3. The model spread among ensemble members is especially large in summer and winter in the two southern Southeastern areas (SEPA-3 and SEPA-4), indicating high model uncertainty for precipitation in this region.

The 9505 projections for runoff change in the Southeastern region show even less clear patterns than precipitation changes (right column in Figure 6-4). The projected changes in runoff (in percentages relative to the 1960–1999 baseline runoff) are similar to the annual and seasonal projections of precipitation in terms of both sign and magnitude of change. There are no clear trends in mean annual runoff except possibly in SEPA-2 and SEPA-3, where there are slight decreasing trends and the medians are less in the mid-term than in the near-term. The spread among ensemble members is especially great in summer, again indicating model uncertainty and regional high variability.

The extremes in hydrology in the Southeastern region are projected to increase with the 9505 methods (Figure 6-5) as dry years increase in frequency and normal years are projected to be less frequent. Water year types are defined by annual runoff values for the baseline period. Annual runoff values lower than the lower 20% quantile during the baseline period are designated as dry years and values greater than the upper 80% quantile are designated as wet years. Figure 6-5 shows that, in general, dry water years will occur significantly more often and normal and wet years will decrease somewhat; the only exception is

SEPA-1, which shows more wet *and* dry years, implying large variance. These types of projections, since Southeastern precipitation and runoff are known to exhibit large interannual variability, may be especially important to consider in light of less-compelling projections of positive or negative trends in runoff.

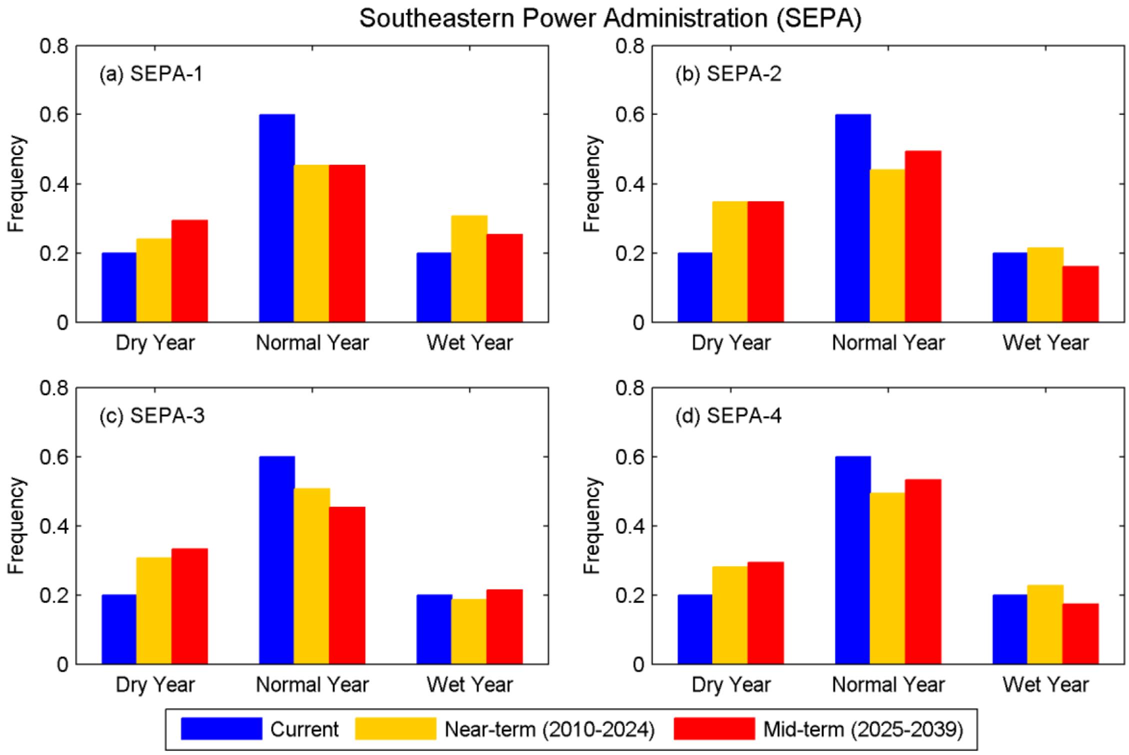

Figure 6-5. Projected frequency of water year type in the Southeastern region, based on the 9505-simulated runoff. Dry, normal, and wet water years are defined by the lower 20%, middle 60%, and upper 20%, respectively, compared with the 1960–1999 baseline period. These reference values are designated with blue bars to left of each group.

The extremes in low flow conditions in Southeastern rivers, as estimated by 10 year return-level quantiles of seasonal low runoff, are also projected to increase (Table 6-3). The 10 year low runoff indicates, statistically, the amount of low flow that may occur every 10 years on average. Strong reduction is projected in nearly all seasons, suggesting that more droughts may occur in the future. The results are consistent with Figure 6-5. Although short-duration wet extremes are not analyzed in this assessment, a recent study (Kao and Ganguly, 2011) suggested that there could be more intense and frequent precipitation extremes, as observed in meteorological reanalysis datasets and projected by GCMs. It suggests the possibility of more frequent flood events, which may increase the difficulty of water management for hydropower operation.

Table 6-3. The 10-year return level quantiles of seasonal low-runoff in the Southeastern region.

	10-year low runoff (inches/season), 1960-1999 baseline simulation			
	Spring (Mar–May)	**Summer (Jun–Aug)**	**Fall (Sep–Nov)**	**Winter (Dec–Feb)**
SEPA-1	2.37	1.18	1.15	2.39
SEPA-2	4.60	1.82	0.94	4.06
SEPA-3	3.93	2.35	1.99	4.03
SEPA-4	3.45	2.32	1.93	3.59
	10-year low runoff (inches/season), 2010-2024 future projection and percent change from baseline[a]			
	Spring (Mar–May)	**Summer (Jun–Aug)**	**Fall (Sep–Nov)**	**Winter (Dec–Feb)**
SEPA-1	1.57 (−34%)	1.10 (−7%)	1.04 (−10%)	1.79 (−25%)
SEPA-2	3.62 (−21%)	1.53 (−16%)	0.96 (2%)	3.70 (−9%)
SEPA-3	2.72 (−31%)	2.06 (−12%)	1.94 (−3%)	3.40 (−16%)
SEPA-4	2.66 (−23%)	2.10 (−9%)	1.72 (−11%)	3.34 (−7%)
	10-year low runoff (inches/season), 2025-2039 future projection and percent change from baseline[a]			
	Spring (Mar–May)	**Summer (Jun–Aug)**	**Fall (Sep–Nov)**	**Winter (Dec–Feb)**
SEPA-1	1.59 (−33%)	1.13 (−4%)	1.05 (−9%)	2.11 (−12%)
SEPA-2	3.06 (−33%)	1.30 (−28%)	0.94 (1%)	2.91 (−28%)
SEPA-3	3.15 (−20%)	1.86 (−21%)	1.94 (−2%)	2.88 (−29%)
SEPA-4	3.01 (−13%)	1.67 (−28%)	2.20 (14%)	2.97 (−17%)

[a] The percentage indicates the relative change compared with baseline.

6.3.2 Other Climate Studies in the Southeastern Region

These 9505 Assessment projections of temperature, precipitation, and runoff for the Southeastern region across 2010–2039 cannot be directly compared with projections from other available studies because of several factors, such as differences in spatial domain, differences in GHG emissions scenarios in the models, different spans of baseline and projection periods, and the fact that the output has been statistically bias-corrected. Nonetheless, some qualitative statements and comparisons between this assessment and other studies can be made.

In an early modeling study, Lettenmaier et al. (1999) used downscaled climate change scenarios from transient climate change experiments performed with coupled ocean–atmosphere GCMs for the 1995 IPCC assessment (IPCC 1996) to examine potential impacts on the Savannah River and ACF systems (coinciding largely with SEPA-3 and -4). They used simulations from three of the leading modeling centers of that era that had somewhat different sensitivities and that of course predated the A1B emissions scenario used in the 9505 Assessment. In effect, these simulations assumed increases in atmospheric CO_2 of 1% per year. Projections of several variables were output for "IPCC Decades 2 and 5" (2020 and 2050; with the decade centered on the year); other decadal projections before 2050 were determined by interpolation. The ranges of averaged projected temperature increase for the two river systems were about 3.0–4.0°F for the 2020 decade and 3.0–5.4°F for the 2040 decade. For precipitation, increases of 3–9% for 2020 and 3–13% for 2040 were projected; for runoff, averages ranged from –4 to 11% and –7 to 20% for these two decades. The authors concluded that precipitation changes, on the whole, were less consistent than temperature changes and followed few monotonic trends. They also stated that the modeled sensitivity of runoff to temperature tended to be less than its sensitivity to precipitation, and that runoff changes mostly followed precipitation changes.

Karl et al. (2009) used the WCRP CMIP3 multi-model dataset (Meehl et al., 2007) combined with the statistical downscaling techniques of Wood et al. (2002) to make temperature and precipitation projections for six large regions of the contiguous United States, including the Southeastern region. These projections show continued warming in all seasons across the entire Southeast, with increasing rates of warming as the century progresses. Projections of temperature changes over 2010–2029 and 2080–2099, each using the lower-emissions (B1) and higher-emissions (A2) scenarios (which essentially bracket the medium-emissions A1B scenario used in the 9505 Assessment), were also discussed. The first period, which aligns closely with the near-term period of the 9505 Assessment, indicates temperature changes under both emissions scenarios on the order of 1.8°F, whereas the 2080–2099 projections are about 4.5 and 9.0°F under the lower- and higher-emissions scenarios, respectively. The approximate midpoint of these "bracketing" projections for 2080–2099 would be a reasonable extension of the 9505 Assessment's 2025–2039 projected warming of about 2.7°F. The Karl et al. projections of changes in precipitation are given for 2080–2099 (for the higher-emissions scenario), so comparisons with the 9505 Assessment cannot readily be made. However, as in the 9505 Assessment projections, no definitive changes in mean annual precipitation were found, even for this later time period. Their projections do show some decrease in precipitation on the order of 5–10% for winter, and especially spring, in the more southern reaches of the region.

The NARCCAP (Mearns et al., 2009) temperature and precipitation projections can also be generally compared with the 9505 Assessment results. NARCCAP provides results from the CCSM3 (driving GCM of the 9505 Assessment) coupled with the CRCM and MM5I regional models. An important distinction between NARCCAP and the 9505 Assessment is the GHG scenario used; NARCCAP uses A2, presumably resulting in considerably stronger forcing, especially later in the 21st century. Seasonal projections for 2041–2170 (relative to a 1971–2000 base period) are readily available from the NARCCAP website. The CCSM+CRCM projections over the Southeastern region for 2041–2070 show the summer months warming the most, with increases of 5.4–7.2°F, followed in magnitude by fall, spring, and winter. These projections may be described as essentially extrapolations of the magnitude of warming found for 2010–2039 in the 9505 Assessment, and the seasonal ranks for the region as a whole are the same. CCSM+CRCM projections of precipitation over 2041–2070 are generally negative over all seasons except autumn but not strongly so (largest decreases are on the order of –10%). These results are similar to the 9505 Assessment in regard to projected increases in fall precipitation (Figure 6-4) and also consistent with the 2080–2099 projections of Karl et al. (2009). The CCSM+MM5I projections of warming over 2041–2070 are generally weaker than in CCSM+CRCM, especially in summer (~3.6–5.4°F), for which they differ little from the 9505 Assessment projections for 2025–2039. CCSM+MM5I projections of changes in precipitation are also quite different from both CCSM+CRCM and 9505 Assessment projections, with little indication of decreasing precipitation except for summer (–5 to –20%).

6.4 EFFECTS ON HYDROPOWER GENERATION IN THE SOUTHEASTERN REGION

6.4.1 Projection of Hydropower Generation

Combining the annual runoff-generation relationship (Figure 6-3) with the projection of future runoff (Figure 6-4) enables a projection of annual hydropower generation (Figure 6-6). The average simulated generation during the baseline period is computed for each of the Southeastern assessment areas, along with their corresponding projected changes in the two future periods. Similar to the style in Figure 6-4, the minimum, median, and maximum of the 9505 ensemble are shown. To avoid bias embedded in the VIC modeling, the simulated annual runoff is bias-corrected using the USGS WaterWatch observed runoff. In Figure 6-6, the dashed line for baseline reference is the mean of simulated 1960-1999 annual generation across five ensemble members; circles are the 15-year mean for the median ensemble member; and the range plotted around each circle extends from the highest to the lowest ensemble member as a measure of model uncertainty. The numerical results are presented in tables in Appendix H. The minimum and maximum annual hydropower generation during the simulated baseline period (1960–1999), simulated near-term period (2010–2024), simulated mid-term period (2025–2039) and observed recent 20-year period (1989–2008) are also summarized in Appendix H. Detailed cumulative distributions of observed and simulated annual generation are illustrated in Appendix I for each Southeastern assessment area.

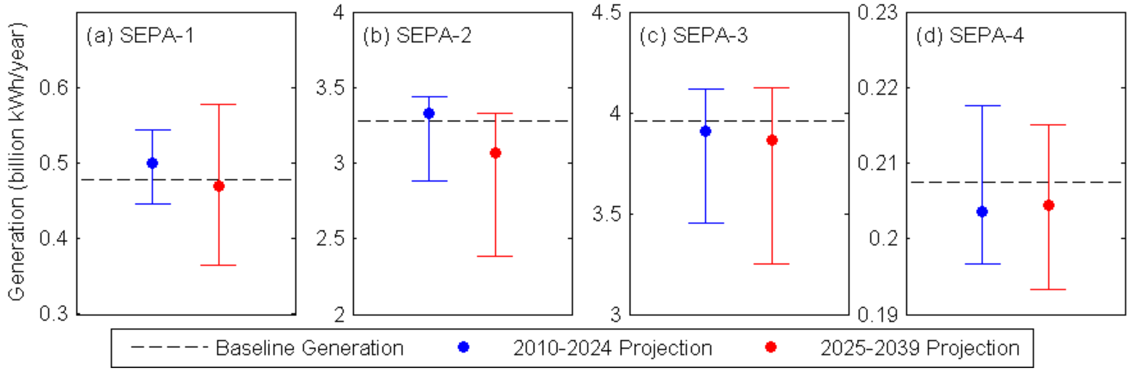

Figure 6-6. Projected annual hydropower generation in the Southeastern region, based on observed correlations with runoff. The dashed line for baseline reference is the mean of simulated 1960–1999 annual generation across five ensemble members; circles are the 15-year mean for the median ensemble member; and the range plotted around each circle extends from the highest to the lowest ensemble member as a measure of model uncertainty.

According to the median 9505 ensemble, a slightly decreasing trend of hydropower generation is projected in the Southeastern region. The minimum and maximum 15-year ensemble means range from decreasing to increasing, suggesting a large uncertainty bound. Although the projected change will add to the historic variability, the change is mostly in a smaller scale in the Southeastern region. Therefore, the climate impact on Southeastern hydropower generation may not be significant within the assessment period. Although there could be more dry years, as suggested by the 9505 simulation results, the range of long-term change in generation should be similar to what Southeastern has encountered in the past 20 years. The relatively large storage capacity in the federal system in this region should be a buffer to climate variability, at least to some degree, as long as it is available for power uses.

6.4.2 Indirect Effects

As used in this report, "indirect effects" refers to climate-related changes to federal hydropower operations that are not included in our 9505 Assessment modeling approach and that can be expected to occur in addition to changes in precipitation and runoff. For example, some changes in air temperature are addressed in the 9505 Assessment models; but changes in air temperature will also affect energy demands and usage patterns, which may trigger changes in hydropower generation that are important in balancing power systems. Such an effect is highlighted early in the most recent NPPCC Briefing Book (NPPCC, 2010) and in the CCSP SAP 4.5 report on climate impacts on the energy sector (CCSP, 2007).

The significant increases in summer temperature projected by the 9505 Assessment over the entire Southeastern region (>4.0°F by the mid-term) can be expected to increase total and peak electricity demand to accommodate increased residential cooling needs. This warming may also result in increased evaporation from reservoir surfaces, resulting in less water available for hydropower (CCSP, 2007). This effect is hard to confidently predict, however, as evaporation is not determined solely by water and air temperatures; other climate variables such as relative humidity, solar radiation, and cloudiness play important roles. At any rate, reservoirs with the largest surface areas are those potentially most sensitive to this effect.

Other likely indirect effects on hydropower include temperature-induced changes in water quality and aquatic habitat condition (Meyer et al., 1999). Possible longer periods of low summertime streamflow, associated with more frequent low-runoff years (e.g., the mid-term period in Figure 6-5), could lead to increased algae growth, resulting in eutrophic conditions in reservoirs. Such effects may, depending on location and severity, require changes in hydropower project operation that reduce power production (CCSP, 2007).

Another indirect effect brought about by increasing warm-season temperatures may be increasing electricity demand and its effect on GHG mitigation activities if renewable energy sources such as hydropower become less reliable owing to more frequent dry years (e.g., the mid-term period in Figure 6-5). Some states in the Southeastern region have established renewable portfolio standards; less hydropower generation may affect the future development of other renewable capacity (e.g., solar, biomass, or wind) and/or result in utilities purchasing more electricity generated by renewable sources from other states.

6.4.3 Implications to Federal Power in Southeastern's Region

Long-term Power Contracts: All of the capacity and energy produced at the USACE projects marketed by Southeastern are allocated to customers through long-term contractual arrangements. These contracts specify the amount of capacity and energy available to each customer. Each contract also has provisions for dispersing power in excess of the contractual obligation and for replacement mechanisms if project operations cannot support the minimum requirements.

Power operations are coordinated with USACE. USACE is responsible for the overall operation of the river basins and, in that role, maintains the basin Water Control Manuals that specify project release requirements. Southeastern participates in each revision of these manuals and seeks to maximize the hydropower benefits.

Southeastern believes these contracts contain sufficient flexibility to respond to the expected climate changes presented in the 9505 Assessment.

Contingency Capacity Contracts: Purchase power is one of the mechanisms used in cases when project operations are insufficient. Southeastern maintains a list of potential providers and, through a bidding process, makes arrangements for the delivery of replacement power to its customers. The process of purchasing power is coordinated with USACE. Each storage project has an elevation guide curve used by USACE in determining the release pattern of each project. Southeastern and USACE routinely communicate hydrologic forecasts. These forecasts provide information to Southeastern concerning expected inflow and the potential shortfalls in generation. Southeastern can then make a preemptive decision to purchase replacement power and conserve project storage for a time when replacement power would be more expensive or seasonal operations would restrict the deliverability of replacement power.

Pumped power is another means of providing energy when hydrologic conditions are insufficient to meet contractual requirements. Southeastern has two pumped-storage projects in its marketing area. Pumping provides short-term flood control and increased availability of generation for contract energy during drought conditions when natural inflow is diminished, or to offset replacement purchases at higher prices from fossil fuel sources.

Southeastern uses customer funding agreements, when possible, to provide for replacement and refurbishment of failed or damaged generating equipment that would otherwise remain out of service while awaiting congressional appropriations. Customer funding expedites the rehabilitation of existing generating equipment, which increases power production and enhances equipment reliability. Utilization of this funding maximizes the availability of renewable generation resources.

Southeastern believes these processes have already been implemented in such a way as to respond to the expected climate changes presented in the 9505 Assessment.

Short-term Sales: Southeastern does not currently have any provisions for short-term sales. All power is marketed on a long-term basis. This marketing policy is aligned with the intent of Section 5 of the Flood Control Act of 1944 to market power at the lowest possible rate.

7. SUMMARY AND CONCLUSIONS

The 9505 Assessment described in this report is the first comprehensive assessment of climate change impacts that specifically focuses on the entire federal hydropower portfolio in the United States. The methods described in Section 2 were designed to provide an objective, quantitative evaluation of the effects and risks to federal hydropower that could be applied consistently across all four PMA regions. The results of the assessment were described for each of the PMA regions in Sections 3 through 6 and are summarized in this final section.

7.1 INTERREGIONAL COMPARISONS

Both the current and the future hydroclimatic conditions at federal hydropower projects vary seasonally and spatially (Figure 7-1), as would be expected. Based on averages over the watersheds above federal hydropower projects, Southeastern's region is the wettest, along with the BPA-4 (Cascade watersheds in southeast Oregon) and WAPA-6 (northern Central Valley of California) areas. Western's region is the driest except for WAPA-6. The Bonneville and Western regions are the only ones with average winter temperatures below freezing (Figure 7-1b); this is an indication of the importance of water storage in the form of ice and snow to the hydrology of those regions, relative to the others. Average temperatures in the summer are highest in the Southwestern and Southeastern regions.

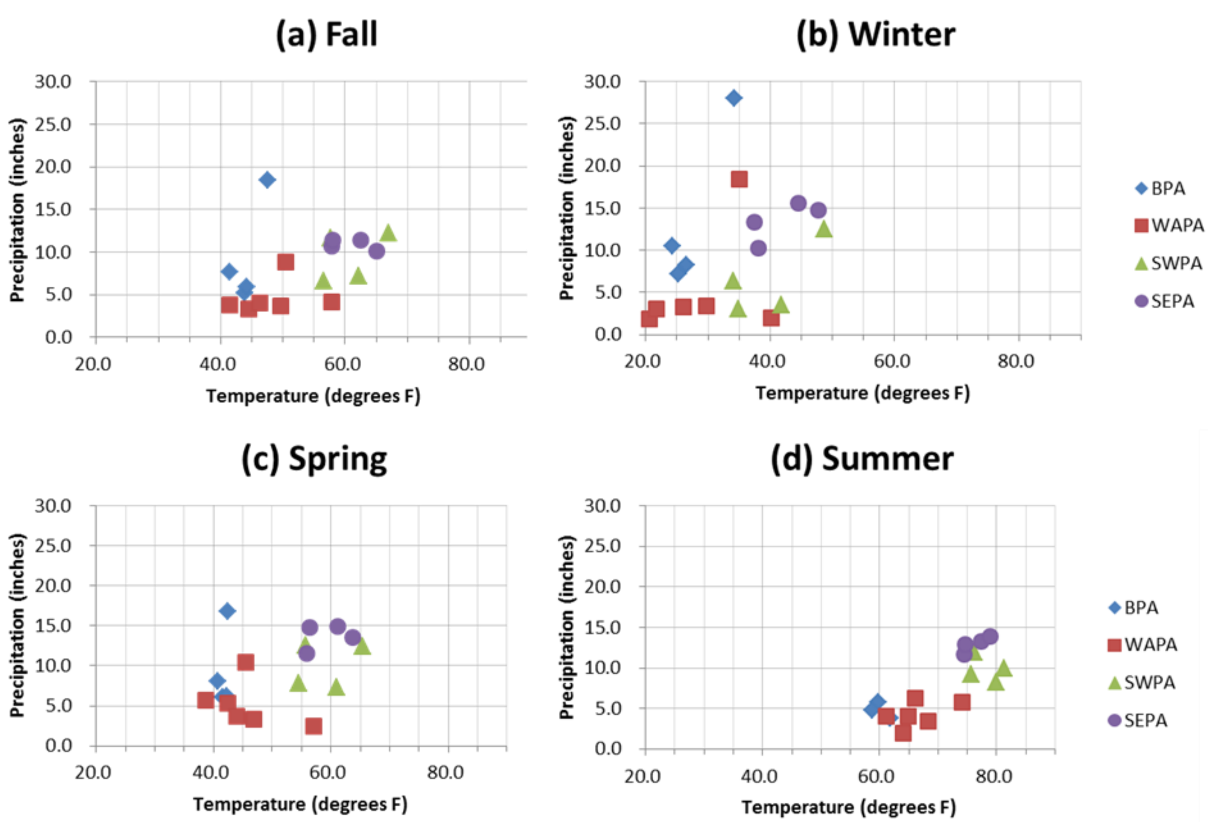

Figure 7-1. Comparison of precipitation and temperature conditions among the PMA regions, based on observational data from 1960 to 1999. *Source*: PRISM data, Daly et al., 2002.

One way to summarize the 9505 future climate projections is to analyze for statistically significant trends. The longest available period to do so from the 9505 dataset is the 80 year period from 1960 to 2039, which includes the longest available period of record in observations and all of the projected future climate conditions generated from the 9505 modeling (Section 2.2). Statistical analysis of the climate trends across this 80 year period shows a mixed pattern of significance (Table 7-1). The trend analysis applied uses a Mann-Kendall test at a 95% significance level, and it considers both the existing climate variability and the variability of future projects in all five members of the 9505 simulation ensemble. Such trend analyses are very sensitive to their length and starting point, so different conclusions may be drawn with different datasets. Nevertheless, the trend analysis results in Table 7-1 can be interpreted as follows (note: these statements apply only to the 80 year period, not to shorter-interval trends).

- Air temperature is likely to be increasing in all regions and areas of analysis through 2039 compared with the recent past (1960 to 2008).
- Except in two Southwestern areas, there is no significant pattern of change in annual or seasonal precipitation through 2039, most likely because of year-to-year variability. In the SWPA-2 and SWPA-3 areas (Arkansas, Red, and Brazos River Basins in Kansas, Oklahoma, and northern Texas), summer precipitation is likely to decrease significantly; but in other seasons, change will not be significantly different from the recent past.
- In all areas of the Bonneville region, summer runoff will significantly decrease relative to the recent past; but no consistent, statistically significant changes in other seasons are indicated over the 80 year period.
- In the Western region, runoff in the spring season will increase in the two northern-most areas (WAPA-1 and WAPA-2, upper Missouri River Basin and Rocky Mountain watersheds in Wyoming and Colorado); summer runoff is likely to significantly decrease in more southern and western areas; no other seasonal changes are apparent.
- There are no statistically significant patterns in runoff in any areas of the Southwestern or Southeastern regions.

Despite the relatively few significant trends in the longer-term analysis, there are other important, shorter-term trends that should not be ignored, even though they may not pass the test for statistical significance. These are described in the previous sections on each region, as well as in research by others (e.g., Milly et al., 2005; Karl et al., 2009; Mearns et al., 2009; Brekke et al., 2011). Scientific consensus is building that hydrologic conditions in the future, especially later in the 21st century, will not be the same as they were in the 20th century, because of both climate change and other nonclimate factors such as land-use and water-use changes (Gleick and Adams, 2000; Milly et al., 2008; Olsen et al., 2010).

7.1.1 Water Availability for Hydropower

Runoff, aggregated spatially over the watersheds upstream of federal projects, is the primary hydrologic variable used to estimate water availability for hydropower. Because of the large number of federal hydropower projects considered in the 9505 Assessment, it was not possible to develop methods that route runoff down through river networks to each project. Storage of water in surface reservoirs was not included in this analysis because of lack of operational data consistent across all projects. Nevertheless, based on the strong correlation observed between annual runoff and generation data (Section 7.1.2), runoff proved to be an adequate assessment variable for this first 9505 Assessment.

Table 7-1. Trend analysis for the 9505 simulation data across the 80 year period from 1960 to 2039. Numbers in cells indicate the number of ensemble members with significant trends, and the sign indicates the direction of change; shaded and bolded cells indicate the strongest significant trends, where a majority of ensemble members have significant trends; zero values indicate no significant trends.

Area of analysis	Temperature					Precipitation					Runoff				
	A	Sp	Su	F	W	A	Sp	Su	F	W	A	Sp	Su	F	W
BPA-1	**5+**	**5+**	**5+**	**4+**	**5+**	0	1+	0	1+	0	0	0	**5-**	0	0
BPA-2	**5+**	**5+**	**5+**	**4+**	**5+**	0	0	1-	0	0	0	1+	**5-**	0	1+
BPA-3	**5+**	**5+**	**5+**	**4+**	**5+**	0	0	1-	1+	0	0	0	**5-**	0	1+
BPA-4	**5+**	**5+**	**5+**	**4+**	**5+**	1-	1-	0	1+	0	1-	1-	**5-**	1+	1+
WAPA-1	**5+**	**4+**	**5+**	**4+**	**5+**	2+	2+	0	2+	0	2+	**4+**	2+	2+	2+,1-
WAPA-2	**5+**	**5+**	**5+**	**5+**	**5+**	0	1+	2-	0	1+	1+,1-	**3+**	**3-**	1-	2+,2-
WAPA-3	**5+**	**5+**	**5+**	**5+**	**5+**	0	0	2-	0	1+,1-	1+,1-	2+	**4-**	1-	2+
WAPA-4	**5+**	**5+**	**5+**	**5+**	**5+**	0	0	1+,1-	0	1-	1+,1-	1+	**4-**	1-	1+
WAPA-5	**5+**	**5+**	**5+**	**5+**	**5+**	1-	0	2-	0	1-	2-	1+,1-	2-	1-	2-
WAPA-6	**5+**	**5+**	**5+**	**5+**	**5+**	0	0	2-	0	1-	1-	1-	**4-**	0	1+
SWPA-1	**5+**	**5+**	**5+**	**5+**	**4+**	1-	0	2-	0	0	1-	0	0	1-	1-
SWPA-2	**5+**	**5+**	**5+**	**5+**	**5+**	1-	1+	**3-**	0	0	1-	1+	1-	1-	0
SWPA-3	**5+**	**5+**	**5+**	**5+**	**5+**	1-	0	**3-**	0	0	1-	0	2-	1-	0
SWPA-4	**5+**	**5+**	**5+**	**5+**	**4+**	1+	0	1-	1+	0	1+	0	1-	1+,1-	0
SEPA-1	**5+**	**5+**	**5+**	**5+**	**4+**	0	0	1+,1-	0	0	0	0	1+,1-	0	0
SEPA-2	**5+**	**5+**	**5+**	**5+**	**3+**	1-	0	2-	0	0	1-	0	0	1-	1-
SEPA-3	**5+**	**5+**	**5+**	**5+**	**3+**	1-	0	1+,1-	0	0	0	0	1+,1-	0	0
SEPA-4	**5+**	**5+**	**5+**	**5+**	**3+**	0	0	1+,1-	0	1-	0	0	1+,1-	1+	0

Spatial patterns in the projected runoff changes are shown in Figure 7-2 across all PMA regions. The PMA areas with the greatest projected increases in runoff are in the Missouri River Basin (WAPA-1 and, to a lesser degree, WAPA-2). In the WAPA-1 area, average annual runoff is projected to increase by 18% in the near-term period (2010–2024) and 21% in the mid-term period (2025–2039). Most of this increase will be in the form of higher spring runoff (for details see Section 4.3).

Median annual runoff values for all Bonneville areas are projected to decrease by 8–10% in the near-term but then show less of a decrease in the mid-term period, according to the models used in this assessment. More important for Bonneville, the greatest decreases in runoff will be in the summer season, when median changes could be as high as 40 to 50%. Although those changes are for median conditions over the 15 year time periods, both high- and low-runoff years will continue to occur. In high-runoff years, the range of ensemble members would indicate that annual runoff may be 10 to 20% higher than in the baseline period.

As median values of runoff are expected to change over time, the frequency of occurrence of both wet and dry water years will also change relative to recent experience. In almost all areas examined, the frequency of normal water years (defined by the middle 60% of baseline years) decreases and the extremes increase. In the Bonneville and Southeastern regions, dry water years can be expected to be 20 to 70% more frequent (for reference, a 50% increase in frequency would equate to one more dry or wet year over a decade). In contrast to those regions, the Western and Southwestern regions will experience more frequent wet water years, at least in the near-term period. By the mid-term period, drier water years will be substantially more frequent, except in the upper Missouri River Basin and in coastal areas of Texas and the Southeast.

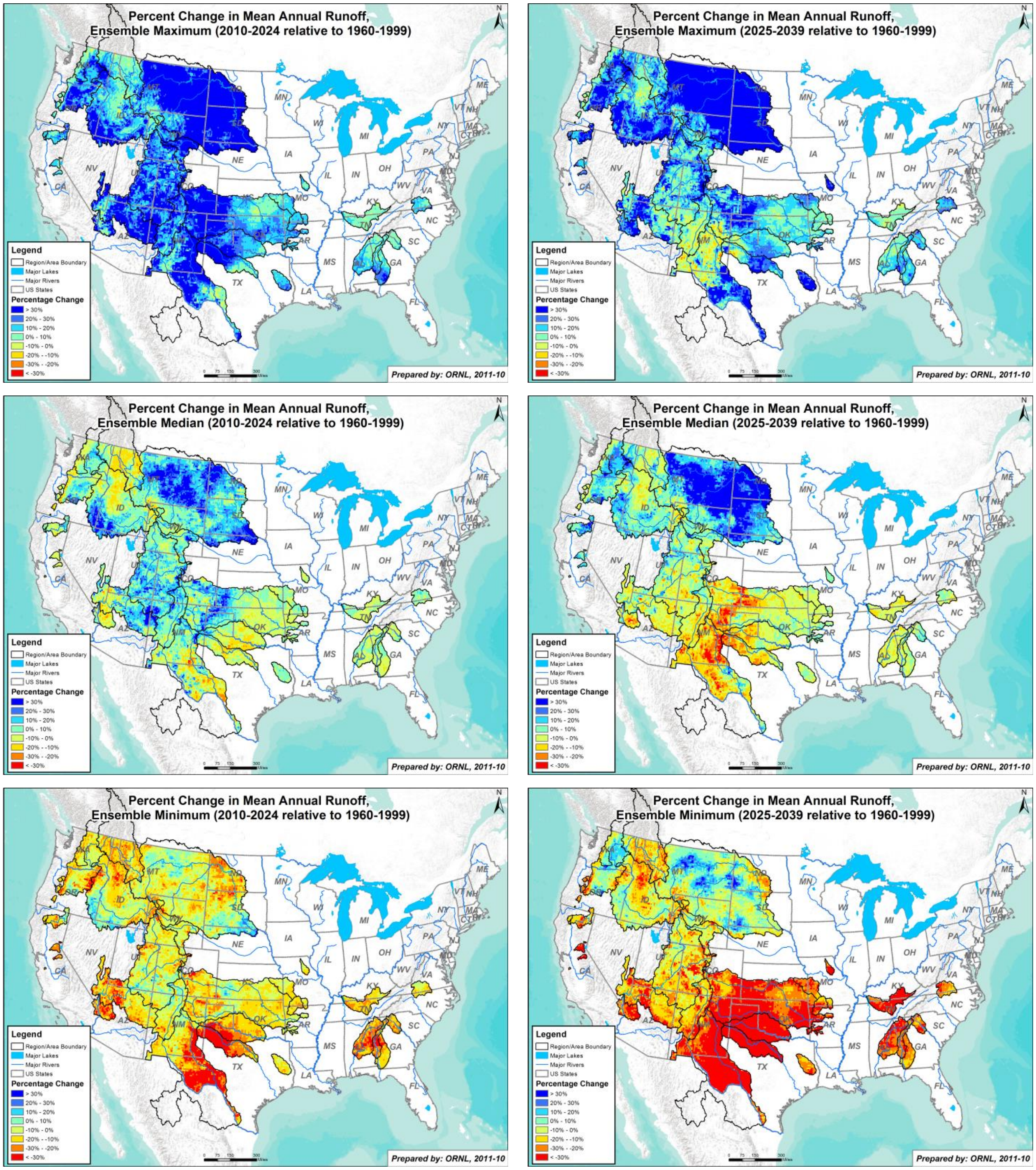

Figure 7-2. Change in runoff projected for PMA regions over the near-term period (2010–2024, left) and the mid-term period (2025–2039, right), based on the minimum, median, and maximum of the five ensemble members.

7.1.2 Generation at Federal Hydropower Plants

The Bonneville region dominates the federal hydropower statistics because it accounts for 65% of all federal power generation. The average annual generation values over the baseline period of 1960–1999 for the Bonneville, Western, Southwestern, and Southeastern regions are 80.6, 29.9, 5.7, and

7.9 billion kWh, respectively. Annual generation is highly correlated with the runoff values that were used to represent water availability for hydropower in almost all of the areas of analysis (Table 7-2 and the column for R^2 values). Simple linear regressions with runoff as the independent variable are sufficient to explain almost all of the variation in annual generation everywhere except the first five Western areas and SEPA-4. When multi-year runoff values were used in the regression analysis, the problematic areas dropped to just two, WAPA-5 and SEPA-4. The most likely reason for the weak correlation in WAPA-5 (Rio Grande River) is poor data availability for runoff in the Mexican portion of that watershed. The weak correlation in SEPA-4 may be caused by hydropower operational issues (e.g., unplanned outages) at the J. Woodruff project, the only hydropower plant in that area.

Table 7-2. Generation versus runoff regression parameters for the PMA regions analyzed, best fit to data

PMA Study Area	Independent variable (inches)	Slope, a	Intercept, b	R^2	Standard error (TWh/year)
BPA-1	single-yr runoff	1.0447	5.5456	0.868	1.573
BPA-2	single-yr runoff	1.0480	3.4254	0.941	0.715
BPA-3	single-yr runoff	1.7227	18.5209	0.770	2.759
BPA-4	single-yr runoff	0.0209	0.8182	0.729	0.161
WAPA-1	two-yr runoff	4.5304	-0.1372	0.791	1.585
WAPA-2	two-yr runoff	0.2071	0.6648	0.783	0.117
WAPA-3	three-yr runoff	1.7990	0.8381	0.801	0.684
WAPA-4	five-yr runoff	1.6838	2.3765	0.661	0.590
WAPA-5	single-yr runoff	0.2860	0.0016	0.181	0.109
WAPA-6	single-yr runoff	0.2243	2.0639	0.706	0.823
SWPA-1	single-yr runoff	0.1482	0.3269	0.863	0.361
SWPA-2	single-yr runoff	0.4091	1.2052	0.729	0.453
SWPA-3	single-yr runoff	0.3095	0.2304	0.828	0.127
SWPA-4	single-yr runoff	0.0094	0.0579	0.765	0.028
SEPA-1	single-yr runoff	0.0369	-0.0290	0.984	0.026
SEPA-2	single-yr runoff	0.1069	0.8243	0.832	0.364
SEPA-3	single-yr runoff	0.1190	1.3406	0.815	0.442
SEPA-4	single-yr runoff	0.0038	0.1353	0.276	0.042

The slope of the generation-to-runoff regressions is an indicator of how sensitive federal hydropower is to changes in runoff in each area of analysis. The areas where federal power is most sensitive to runoff are WAPA-1 (upper Missouri), BPA-3 (lower Columbia), WAPA-3 and WAPA-4 (Colorado River), BPA-1 (upper Columbia), and BPA-2 (Snake). These areas have the highest installed capacity of federal hydropower. The least sensitive areas generally have fewer and smaller projects, such as SWPA-4 and SEPA-4. There are other characteristics of hydropower systems that will determine sensitivity to climate change that were not included in the 9505 Assessment models because of a lack of site-specific data. They include the sizes of active power pools in reservoirs relative to inflows, and project-specific operating rules. Improvements in assessment data and models will be needed to address those issues.

Future changes in annual hydropower generation can be estimated from projected changes in runoff and the generation-to-runoff regression relationships (Section 2.2.4 and Table 7-3). The largest changes in amount of generation are in Bonneville's region, but because of the high installed capacity in the FCRPS, the percentage changes for Bonneville are less than those for Western. For Western, increases in WAPA-1 tend to balance decreases elsewhere in the region, especially in the mid-term period. The ranges in change estimates shown in Table 7-3 are based on the lowest and highest of the five-member ensemble of climate model outputs, not on a more explicit estimate of extreme events that could occur. Nevertheless, those ranges provide useful insights into the fact that both high and low water years will continue to occur in the future, and some areas will be more susceptible to wetter or drier conditions. For example, in the mid-term period (2025–2039), the WAPA-5, SWPA-1, SWPA-3, SEPA-1 and SEPA-2 areas could experience years in which generation is 20 to 30% less than the baseline (Table 7-3). In contrast, the SWPA-4 and SEPA-1 areas could experience increases in generation up to 20% greater than the baseline. Increases in generation in WAPA-1 could exceed 50% of the baseline. All of the climate-related estimated runoff and generation changes would occur at the same time as other nonclimate changes in water resource management. The cumulative effects of climate and nonclimate impacts cannot be determined with the methods used in this 9505 Assessment.

Table 7-3. Projected changes in hydropower generation compared with the mean of simulated 1960–1999 annual generation across five ensemble members

Area of analysis	Baseline 1960-1999 simulated annual generation (billion kWh/yr)	Near-term change (2010‑2024)		Mid-term change (2025‑2039)	
		Median change (billion kWh/year)	Range (percentage)	Median change (billion kWh/year)	Range (percentage)
BPA total	80.6	–3.869	–6% to 5%	–0.044	–8% to 3%
BPA-1	25.2	–1.779	–10% to 7%	–0.105	–10% to 2%
BPA-2	12.9	–0.633	–6% to 6%	–0.293	–8% to 9%
BPA-3	40.7	–1.401	–5% to 4%	–0.092	–7% to 3%
BPA-4	1.8	–0.083	–7% to 2%	–0.026	–12% to 1%
WAPA total	29.9	3.482	2% to 17%	1.141	–4% to 24%
WAPA-1	10.6	1.715	–3% to 34%	2.542	7% to 54%
WAPA-2	1.5	0.041	–6% to 18%	0.011	–7% to 8%
WAPA-3	6.3	0.750	–5% to 16%	–0.374	–16% to 9%
WAPA-4	6.5	0.555	–7% to 13%	–0.190	–13% to 8%
WAPA-5	0.2	0.012	–15% to 14%	–0.011	–29% to 7%
WAPA-6	4.8	0.088	–9% to 6%	0.345	–10% to 8%
SWPA total	5.7	–0.103	–3% to 10%	0.037	–23% to 3%
SWPA-1	2.2	–0.050	–4% to 12%	–0.019	–26% to 12%
SWPA-2	2.6	–0.001	–1% to 8%	–0.069	–18% to 3%
SWPA-3	0.7	–0.050	–13% to 16%	–0.019	–33% to 8%
SWPA-4	0.1	0.001	–7% to 8%	–0.001	–14% to 26%
SEPA total	7.9	0.044	–10% to 4%	–0.045	–22% to 2%
SEPA-1	0.5	0.022	–7% to 14%	–0.008	–24% to 21%
SEPA-2	3.3	0.049	–12% to 5%	–0.209	–27% to 1%
SEPA-3	4.0	–0.048	–13% to 4%	–0.093	–18% to 4%
SEPA-4	0.2	–0.004	–5% to 5%	–0.003	–7% to 4%
Total federal hydropower	124.4	–2.022	–4% to 8%	–1.394	–8% to 8%

Note that all "projected changes" reported in this study refer to the mean of simulated 1960–1990 annual generation across the five ensemble members. Although the range of projected change may slightly shift when compared with a different baseline (as in Table 7-4 with observed 1989–2008 annual generation), the relative findings across different study areas should remain the same.

Table 7-4. Projected changes in hydropower generation, compared with the observed 1989–2008 annual generation

Area of analysis	Observed 1989–2008 annual generation (billion kWh/year)	Near-term change (2010–2024)		Mid-term change (2025–2039)	
		Median change (billion kWh/year)	Range (percentage)	Median change (billion kWh/year)	Range (percentage)
BPA total	77.1	−0.342	−2% to 10%	3.483	−4% to 7%
BPA-1	24.4	−0.975	−7% to 10%	0.699	−7% to 6%
BPA-2	11.7	0.533	4% to 16%	0.873	2% to 20%
BPA-3	39.2	0.111	−1% to 8%	1.420	−3% to 7%
BPA-4	1.8	−0.038	−5% to 5%	0.019	−10% to 4%
WAPA total	26.8	6.562	14% to 30%	4.221	7% to 39%
WAPA-1	9.1	3.220	13% to 56%	4.047	25% to 80%
WAPA-2	1.4	0.139	1% to 26%	0.109	0% to 15%
WAPA-3	5.6	1.475	7% to 32%	0.351	−6% to 24%
WAPA-4	6.0	1.083	1% to 23%	0.337	−5% to 17%
WAPA-5	0.2	0.018	−13% to 17%	−0.005	−27% to 10%
WAPA-6	4.6	0.242	−6% to 10%	0.500	−7% to 12%
SWPA total	5.9	−0.303	−6% to 7%	−0.163	−25% to −1%
SWPA-1	2.2	−0.050	−4% to 12%	−0.019	−26% to 12%
SWPA-2	2.7	−0.071	−4% to 5%	−0.139	−20% to 1%
SWPA-3	0.8	−0.164	−26% to −1%	−0.132	−42% to −8%
SWPA-4	0.2	−0.017	−17% to −3%	−0.019	−23% to 13%
SEPA total	7.5	0.476	−5% to 10%	0.386	−17% to 8%
SEPA-1	0.5	0.033	−5% to 16%	0.003	−22% to 24%
SEPA-2	3.2	0.138	−10% to 8%	−0.120	−25% to 4%
SEPA-3	3.6	0.274	−5% to 13%	0.229	−11% to 13%
SEPA-4	0.2	0.005	−1% to 10%	0.006	−3% to 8%
Total federal hydropower	117.2	5.135	2% to 14%	5.764	−2% to 14%

7.1.3 Comparison of Power Marketing Approaches

PMAs differ significantly among each other in terms of installed capacity, number and composition of their customer bases, and sources of financing. Their power marketing approaches reflect to some extent their size, with more options and complexity in the larger PMAs. Differences in power marketing also reflect the hydrologic conditions in each region. For instance, Southwestern sells peaking power only because it has very little storage capacity to help it firm its output. The way WAPA markets its power is related to the historical variability of available hydropower at each of its projects. At those projects with the highest variability, WAPA sells available energy only, rather than energy and capacity.

Bonneville is the only PMA that charges the same rate for a given product throughout its entire service area. This lack of variability in rates across projects is offset by seasonal variability, as Bonneville is also the only PMA in which energy and capacity rates vary on a monthly basis. Southeastern markets all of its power on a long-term basis, whereas the other PMAs have short-term sales options as part of their product portfolio.

Since their creation, PMAs have been tasked with marketing power from hydropower installations whose operation they do not control and, for the most part, sharing water with multiple higher-priority uses. Operating under short-term weather-related variability and long-term uncertainty about competing use demands, they have had to build flexibility into their allocation methodologies and rate structures from the beginning. Such flexibility will become all the more valuable in handling the extra variability in hydropower generation that climate change is projected to cause in the following decades. Although they are articulated in slightly different terms, all the PMAs have ways to reduce allocations if the frequency of dry years increases. Moreover, PMAs share the volume risk inherent to hydropower with their customers in one of two fundamental ways. They either offer contingent capacity contracts under which the customer receives a percentage of annual output (rather than a fixed volume), or they offer firm power along with clauses to enable them to pass through the cost of firming available supplies through market purchases. However, note that the rate adders associated with purchased power were conceived of as temporary instruments to respond to typical variability. They are not well suited to dealing with extreme changes, such as those that occurred in 2001 in the Bonneville region (note: in that 2001 case, stress on the power system came from a "perfect storm" of climate variability, power supply shortages, and older contract and rate structures that have since been replaced).

The names and implementation details used by the PMAs to share risk with customers vary by region:

- Bonneville uses a cost recovery adjustment clause that triggers an increase in energy rates in years in which Bonneville's financial reserves fall below a certain threshold. (The cost recovery adjustment clause does not apply to all customers. For example, it does not apply to slice product customers since they are already bearing the risk of low-hydro-output years by being allocated a percentage, rather than a fixed volume, of FCRPS output.)
- SWPA has an adder to cover costs incurred for purchased power unless the customer is under a contract support arrangement. This adder may be adjusted up to twice a year to reflect differences between the estimated and actual cost of Southwestern's purchased power.
- SEPA has replacement power schedules under which it specifies the allocation of costs from purchased power (except for the Cumberland system, which is an energy-only system under its current interim operating plan).
- Western has drought adders in Loveland and Pick-Sloan Program Projects and replacement power at SLIP and Boulder Canyon. Drought adders are not necessary in energy-only projects (Central Valley Project, Provo, Amistad-Falcon) where hydrology risk is already born by the customers.

Depending on the specific region and contract, the cost recovery may occur after a lag, or there may be limits to how much can be passed through each year. For instance, the Pick-Sloan Program's drought adder uses a balloon payment methodology so that it repays Western's drought debt within 10 years of the year in which it was incurred. These adders are viewed as temporary. Another limit to how much the PMAs may increase rates is the market price itself. If other power marketers in their service area start offering rates below those of the PMAs, then customers might want to get out of their contracts or not renew them when the time comes.

7.2 MAJOR FINDINGS

7.2.1 Assessment Methods and Data

Developing a quantitative assessment approach that could evaluate climate impacts consistently across all federal hydropower projects, in a short period of time, was a major technical challenge. The modeling approach developed for the 9505 Assessment was successful, at least with respect to evaluating changes in annual runoff and hydropower generation. A new, integrated database was assembled to describe hydrology and hydropower at a regional scale for all four PMA regions, and those data were used to develop regression models of average annual generation as a function of runoff. Future climate was simulated with a series of global and regional models, and model outputs were adjusted to be consistent with observed data for the recent past. This modeling framework enabled the projection of current climate conditions into near-term (2010–2024) and mid-term (2025–2039) periods, and an estimation of how changes in water availability would affect hydropower generation at federal projects. The 9505 Assessment results therefore are responsive to the Congressional direction in SWA.

The assessment approach developed in this first 9505 Assessment was not able to address some of the more detailed aspects of climate and hydropower, especially at shorter time intervals (e.g., monthly changes). The assessment models also could not resolve project-specific conditions. The lack of consistent monthly hydrology and generation data was a major reason why more detailed modeling could not be conducted at this time. The complexities of surface water reservoir operations are another factor limiting assessment capabilities. To represent monthly or shorter hydrology in river basins where many multiple-use reservoirs are located, as is the case in almost all federal hydropower systems, a much more detailed water-balance modeling approach would be needed. Such details were beyond the scope of this first 9505 Assessment.

The 9505 Assessment did not attempt to project climate change impacts beyond 30 years into the future, because there are too many other nonclimate issues that will interact with climate effects and that depend on policy decisions of several types. Three of these nonclimate factors are (1) the types and efficiency of hydropower equipment as it is replaced and upgraded over time, (2) the reallocation of water storage in federal reservoirs to nonpower uses, and (3) changing water management requirements for environmental protection and restoration. Each of these factors has the potential to have greater impacts on federal power generation than climate change, at least at specific projects or river basins. Climate change will interact with these additional factors in both synergistic and antagonistic ways that cannot be quantified with existing assessment methods.

The fact that the 9505 Assessment did not examine effects beyond 30 years should in no way be interpreted as meaning that longer-term effects are not important. Quite the opposite is true—climate projections by others into the second half of the 21st century consistently show increasing changes in water availability, more extreme wet and dry conditions, and significantly greater challenges for water managers (e.g., Karl et al., 2009; Hamlet, et al., 2010; Brekke et al., 2011; Reclamation, 2011b). The 9505 Assessment did not attempt to evaluate impacts to hydropower in those longer-term periods for several reasons, ranging from practical limitations of time and resources to the fact that the federal hydropower system will be much different from today. Either the deteriorating condition of federal hydropower will force significant modernization, leading to more efficient equipment and operating policies, or federal power facilities will suffer even greater deterioration in energy performance to the point of being unsustainable (MWH, 2009 and 2010; Sale, 2011). Until the decisions on modernization investments in federal hydropower are much more clear than they are today, long-term predictions of its operation are very difficult and are beyond the scope of this first 9505 Assessment.

The assumptions inherent in the series of assessment models should be recognized. All computational models of complex systems involve simplifying assumptions that enable simulation to be carried out. The series of GCM, regional downscaling, and VIC models used in this 9505 Assessment each has its own set of assumptions that may be improved upon in future assessments. Two of the most important of these are the land-surface parameterization (currently it is fixed for all years and seasons) and human manipulation of water conveyance through river basins (not in GCM or regional models). Improving upon these simplifying assumptions was not possible within the scope of this first 9505 Assessment. Despite the unavoidable modeling assumptions, the assessment approach was useful for SWA Section 9505 purposes.

Although it is impossible to know with absolute certainty how well any model and assessment scheme depicts future conditions a priori, the large degree of agreement among the 9505 Assessment results and the climate modeling results from others builds confidence in the predictions. The weight of evidence is strongly in favor of regional changes, especially with respect to the sign of projected precipitation and runoff changes. Additional confidence is gained from the fact that existing climate models (including those used in the 9505 Assessment) are based on well-established physical principles that have been demonstrated to reproduce observed features of recent climate and past climate changes (IPCC, 2007).

7.2.2 Direct Effects of Climate Change on Federal Hydropower

The climate modeling results from this first 9505 Assessment indicate drying trends and decadal-scale changes that are likely to have adverse impacts on federal hydropower in many regions. These trends are generally consistent with other studies, as reviewed in previous sections. Even against the backdrop of these projected regional drying trends, it is important to note that both wet and dry extremes will continue to occur in the future for all regions, although the relative frequency of these extremes is projected to change. On a longer-term basis, looking beyond the 2010–2039 window on which the 9505 Assessment concentrated, climate change is likely to become even more challenging for hydropower operations if warming, drying, and seasonal shifts in hydrology continue on projected trajectories (e.g., SWA Section 9503 results; Reclamation, 2011a).

The upper Missouri River Basin in the northern Great Plains is an outlier compared with other regions studied, because it is the only area where future conditions are predicted to become significantly wetter. The western slope of the Cascade mountains is another area that may be wetter, especially in the mid-term. Runoff and generation are estimated to increase in those parts of the Western and Bonneville regions.

In contrast to the wetter areas, water availability in the southern Great Plains, Texas, and New Mexico is estimated to substantially decrease in the future. Therefore, Southwestern and Western may experience less hydropower generation in those areas, especially during the drier summer months.

The climate-related range of year-to-year variation in future hydropower generation is estimated to be similar in magnitude to the variability in generation that has been experienced in almost all of the PMA areas over the past 20 years. Although this 9505 Assessment identifies the possibility of low-water and low-generation years, those climate-change-driven extremes are within the range of current variability; therefore, they may be manageable within current PMA marketing practices, at least in the near-term and mid-term periods examined.

7.2.3 Current Capabilities to Manage Risks from Climate Variability

From a power marketing perspective, the PMAs already have many management mechanisms to share generation risk with the power customers of the PMAs, USACE, and Reclamation. The PMAs' ability to increase rates to compensate for purchased power expenses in case of a deficit is indicative of the ability to cope with the projected generation changes stemming from climate variability. One notable exception may be in WAPA-6 (northern California), where under the Custom Products provision of Western's marketing plan, Western is contractually obligated to meet energy requirements for full load service customers. The cost of such energy is passed through to full load service customers under the existing rate schedules. Therefore, a rate increase would not be needed in the WAPA-6 area.

In addition to these existing mechanisms, there are other actions the PMAs may take to prepare for extreme events and resulting power shortfalls. These include drought planning, improved monitoring and forecasting, and continuing climate studies. The Climate Risk Management Team that Bonneville has established is an excellent example of being proactive in the climate change arena (Section 3.1.3 and 3.3.2); other regions could benefit from such initiatives.

Conservation efforts and demand response programs are also relevant tools for PMAs in managing different aspects of climate change risk. Encouraging conservation would be useful as a way to offset reduced generation if climate change manifests itself as a slow, decreasing trend in precipitation. On the other hand, demand response programs can help reshape customer loads and attenuate air-conditioning loads if climate change results in higher summer temperatures.

Many of the power marketing mechanisms needed to cope with change already exist or can be put in place, and the range of estimated variation in federal power may not appear to be greater than what is already being managed. However, the weight of evidence from this 9505 Assessment and other, similar studies suggests greater changes in hydrology and generation are coming. The uncertainties in estimates of the future remain large, but continued monitoring and planning initiatives are warranted.

7.2.4 Interactions with Other Water Resource Management Issues

Climate variability and change are not the only factors affecting water availability for federal hydropower. Other important factors currently influencing federal hydropower are reallocation of water storage to nonpower uses and the aging of federal hydropower assets, which is leading to lower reliability and more outages. Future 9505 Assessments should address the interactions among climate and nonclimate influences on water resources.

It is very likely that the federal hydropower system that exists by 2040, the end of the window of time on which the 9505 Assessment concentrated, will be significantly different from what exists now. For example, Reclamation is actively planning changes in many of its dams and hydropower plants to cope with future changes, including

- replacing older turbines with models that are more efficient overall and models that are more efficient at lower head levels (i.e., better during drought conditions)
- replacing wicket gates to improve flow and efficiency at lower head levels
- continuing work on operations optimization programs and systems to maximize the energy received from the available water

USACE has a similar, very extensive HMI under way which, if successful, should significantly increase the generation per unit of water across its hydropower infrastructure (MWH, 2009 and 2010). These types of changes are likely to occur with or without climate change drivers, and they are critical to the long-term sustainability of federal hydropower (Sale, 2011).

7.2.5 Indirect Effects of Climate Change

As described in the regional sections, indirect effects from future climate change can be expected in addition to the direct effects on temperature, precipitation, and runoff projected by the 9505 Assessment methods. Some of these indirect effects are likely to be experienced, to varying degrees, across all regions (e.g., increases in total and peak electricity demand due to increased residential cooling needs in warmer summers, temperature-driven increased evaporation from reservoir surfaces, potentially resulting in less water available for hydropower). Other indirect effects will be region-specific, such as adverse warming-induced effects on freshwater salmon habitat in the PNW, including longer high-water-temperature periods in summer that result in thermal stress and migration barriers.

7.3 PREPARING FOR FUTURE HYDROPOWER ASSESSMENTS

Section 9505 of SWA instructed DOE to submit a first Report to Congress on climate effects to federal hydropower, then to repeat these assessments every 5 years through 2023. There are a number of ways that the assessment approach presented here can be improved for subsequent assessments.

- Establish an ongoing monitoring, data collection, storage, and analysis effort for hydropower plant operation and generation, with at least monthly resolution at all federal facilities. Do this in cooperation with the PMAs and federal hydropower owners to produce a consistent database for tracking trends against baseline conditions. The integrated database content should include water, power, climate, and financial information (e.g., monthly electricity prices at the NERC subregion level). Data on both energy supply and demand will be needed as well.

- Develop a more detailed modeling approach to link project operations and climate variables to generation patterns and water resource management decisions at federal hydropower projects. The regression approach used in this first 9505 Assessment (runoff versus generation) performed reasonably well, but it was limited in its ability to resolve seasonal and monthly changes. A new modeling approach that incorporates water storage, water surface elevation (i.e., head), and competing water uses throughout upstream watersheds would provide a better understanding of future conditions and mitigation options. The VIC model that was used to estimate future runoff could be improved, especially in dry watersheds, or it could be replaced with more advanced hydrologic models. Improved methods of using more GCM simulations should be investigated, especially since new versions of climate models will be available soon as part of the next round of IPCC reports. The improved modeling capabilities will also enable more in-depth assessment of the impact of hydro-meteorological extremes on hydropower generation, especially for reservoir operation during flood periods and competing water usage during drought periods.

- Integrate climate change assessment with other water resources planning activities so that the full spectrum of factors affecting water availability and use can be considered together. Climate change effects will not be independent of other stressors on water availability, so interactions must be addressed as directly as possible. Cumulative impact assessment, including climate change effects, should be a goal to better inform hydropower planning and resource management policies. Ultimately, federal hydropower, including TVA, and nonfederal hydropower should also be addressed together, because they operate with the same water resources and send their electricity into the same power grids. Other factors that should be considered in more integrated assessment include

    - the water-use intensiveness of growing industrial use and how it affects the nature of the growth in demand for available water supplies

- tradeoffs between hydropower and other sources of energy in a region as they affect GHG emissions and water resource impacts
- benefits and costs of long-term investments in replacement and rehabilitation of the aging hydropower infrastructure

- Explore interactions among the power systems within each PMA and between the PMAs and the larger electric reliability regions or markets in which they operate. PMAs' specialization in hydropower makes them more vulnerable than other electric power marketers to the generation risk associated with climate change. Even though PMAs can pass purchased power expenditures through to their firm power customers, there is a threshold beyond which those customers might find better rates from alternative suppliers. The number of alternative suppliers and the correlation between their generation mix and that of the PMAs affect the probability of reaching that threshold.

- Establish a regular interaction of hydropower interests and the community of scientists working to improve models of future climates, so that the key variables affecting hydropower are incorporated into climate models. This could be done via the DOE Office of Energy Efficiency and Renewable Energy and PMA participation on interagency coordination bodies such as the Federal Climate Change and Water Working Group and the Interagency Climate Change Adaption Task Force. Hydropower interests and expertise need to be directly involved in ongoing studies of climate change so that products from such research are responsive to end-user needs.

8. REFERENCES

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APPENDICES

APPENDIX A. SECTION 9505 OF THE SECURE WATER ACT OF 2009 (PUB L. 111-11)

Section 9505. HYDROELECTRIC POWER ASSESSMENT.

(a) Duty of Secretary of Energy—The Secretary of Energy, in consultation with the Administrator of each Federal Power Marketing Administration, shall assess each effect of, and risk resulting from, global climate change with respect to water supplies that are required for the generation of hydroelectric power at each Federal water project that is applicable to a Federal Power Marketing Administration.

(b) Access to Appropriate Data—

(1) IN GENERAL—In carrying out each assessment under subsection (a), the Secretary of Energy shall consult with the United States Geological Survey, the National Oceanic and Atmospheric Administration, the program, and each appropriate State water resource agency, to ensure that the Secretary of Energy has access to the best available scientific information with respect to presently observed impacts and projected future impacts of global climate change on water supplies that are used to produce hydroelectric power.

(2) ACCESS TO DATA FOR CERTAIN ASSESSMENTS—In carrying out each assessment under subsection (a), with respect to the Bonneville Power Administration and the Western Area Power Administration, the Secretary of Energy shall consult with the Commissioner to access data and other information that—

(A) is collected by the Commissioner; and

(B) the Secretary of Energy determines to be necessary for the conduct of the assessment.

(c) Report—Not later than 2 years after the date of enactment of this Act, and every 5 years thereafter, the Secretary of Energy shall submit to the appropriate committees of Congress a report that describes—

(1) each effect of, and risk resulting from, global climate change with respect to—

(A) water supplies used for hydroelectric power generation; and

(B) power supplies marketed by each Federal Power Marketing Administration, pursuant to—

(i) long-term power contracts;

(ii) contingent capacity contracts; and

(iii) short-term sales; and

(2) each recommendation of the Administrator of each Federal Power Marketing Administration relating to any change in any operation or contracting practice of each Federal Power Marketing Administration to address each effect and risk described in paragraph (1), including the use of purchased power to meet long-term commitments of each Federal Power Marketing Administration.

(d) Authority—The Secretary of Energy may enter into contracts, grants, or other agreements with appropriate entities to carry out this section.

(e) Costs—

(1) NONREIMBURSABLE—Any costs incurred by the Secretary of Energy in carrying out this section shall be nonreimbursable.

(2) PMA COSTS—Each Federal Power Marketing Administration shall incur costs in carrying out this section only to the extent that appropriated funds are provided by the Secretary of Energy for that purpose.

(f) Authorization of Appropriations—There are authorized to be appropriated such sums as are necessary to carry out this section for each of fiscal years 2009 through 2023, to remain available until expended.

APPENDIX B. LIST OF FEDERAL HYDROPOWER PLANTS MARKETED THROUGH POWER MARKETING ADMINISTRATIONS

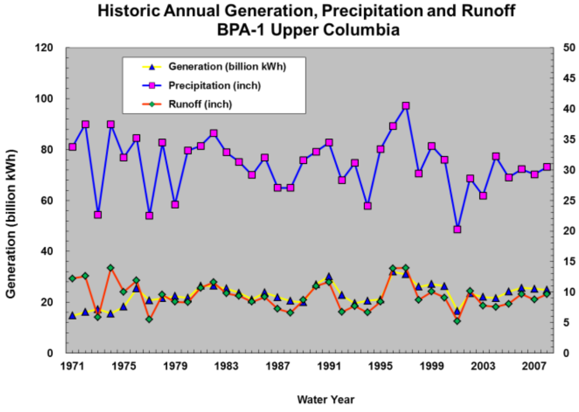
N	Power plant name	Power system	Owner	Generation type	Capacity (MW)	FY 1971–FY 2008 average annual generation (thousand kWh/year)
BPA-1 Upper Columbia						
1	Grand Coulee	Federal Columbia River Power System (FCRPS)	Reclamation	Conventional Hydro	6495	20,016,630
				Pumped Storage	314	
2	Hungry Horse		Reclamation	Conventional Hydro	428	917,417
3	Albeni Falls		USACE	Conventional Hydro	42	216,018
4	Libby		USACE	Conventional Hydro	525	1,970,391
BPA-2 Snake River						
5	Anderson Ranch	Federal Columbia River Power System (FCRPS)	Reclamation	Conventional Hydro	40	133,538
6	Black Canyon		Reclamation	Conventional Hydro	10.2	62,353
7	Boise R Diversion		Reclamation	Conventional Hydro	4.8	2,777
8	Minidoka		Reclamation	Conventional Hydro	27.7	97,866
9	Palisades		Reclamation	Conventional Hydro	176.4	633,776
10	Dworshak		USACE	Conventional Hydro	400	1,745,800
11	Ice Harbor		USACE	Conventional Hydro	603	2,172,195
12	Little Goose		USACE	Conventional Hydro	810	2,569,799
13	Lower Granite		USACE	Conventional Hydro	810	2,553,108
14	Lower Monumental		USACE	Conventional Hydro	810	2,546,621
BPA-3 Mid-Lower Columbia						
15	Chandler	Federal Columbia River Power System (FCRPS)	Reclamation	Conventional Hydro	12	48,343
16	Roza		Reclamation	Conventional Hydro	12.9	59,277
17	Bonneville		USACE	Conventional Hydro	1092.9	4,893,605
18	Chief Joseph		USACE	Conventional Hydro	2456.2	10,715,186
19	John Day		USACE	Conventional Hydro	2160	10,238,507
20	McNary		USACE	Conventional Hydro	990.5	6,301,057
21	The Dalles		USACE	Conventional Hydro	1819.7	7,551,561
BPA-4 Cascade Mountains						
22	Green Springs	Federal Columbia River Power System (FCRPS)	Reclamation	Conventional Hydro	17.2	65,346
23	Big Cliff		USACE	Conventional Hydro	18	96,255
24	Cougar		USACE	Conventional Hydro	26	136,158
25	Detroit		USACE	Conventional Hydro	100	381,825
26	Dexter		USACE	Conventional Hydro	15	74,031
27	Foster		USACE	Conventional Hydro	20	96,983
28	Green Peter		USACE	Conventional Hydro	80	242,993
29	Hills Creek		USACE	Conventional Hydro	30	160,304
30	Lookout Point		USACE	Conventional Hydro	120	33,1673
31	Lost Creek		USACE	Conventional Hydro	49	270,839
WAPA-1 Pick-Sloan-Eastern Division						
32	Canyon Ferry	Pick-Sloan-Eastern Division	Reclamation	Conventional Hydro	49.8	376,874
33	Big Bend		USACE	Conventional Hydro	494.1	958,399
34	Fort Peck		USACE	Conventional Hydro	185.3	1,037,171
35	Fort Randall		USACE	Conventional Hydro	320	1,724,243
36	Garrison		USACE	Conventional Hydro	614	2,225,695
37	Gavins Point		USACE	Conventional Hydro	132.3	723,535
38	Oahe		USACE	Conventional Hydro	784	2,604,414
39	Yellowtail[a]	Pick-Sloan-Eastern Division / Loveland	Reclamation	Conventional Hydro	250	854,285
WAPA-2 Loveland						
40	Alcova	Loveland Area Projects	Reclamation	Conventional Hydro	41.4	120,517
41	Boysen		Reclamation	Conventional Hydro	15	71,155
42	Buffalo Bill		Reclamation	Conventional Hydro	18	63,128
43	Shoshone		Reclamation	Conventional Hydro	3	18,997
44	Heart Mountain		Reclamation	Conventional Hydro	5	25,258
45	Spirit Mountain		Reclamation	Conventional Hydro	4.5	13,941
46	Flatiron		Reclamation	Conventional Hydro	86	228,933
				Pumped Storage	8.5	
47	Big Thompson		Reclamation	Conventional Hydro	4.5	11,199
48	Fremont Canyon		Reclamation	Conventional Hydro	66.8	244,129

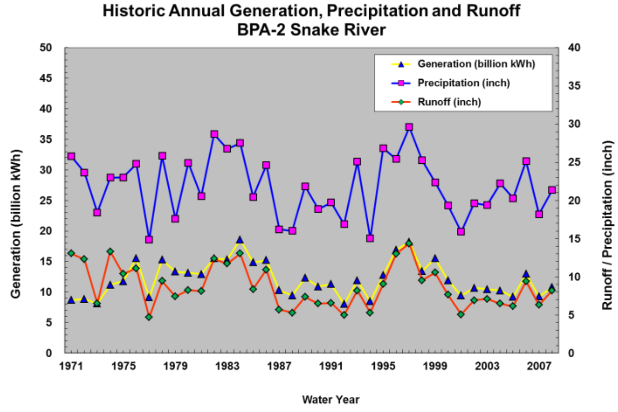
N	Power plant name	Power system	Owner	Generation type	Capacity (MW)	FY 1971–FY 2008 average annual generation (thousand kWh/year)
49	Glendo		Reclamation	Conventional Hydro	38	81,759
50	Green Mountain		Reclamation	Conventional Hydro	26	53,275
51	Guernsey		Reclamation	Conventional Hydro	6.4	19,921
52	Kortes		Reclamation	Conventional Hydro	36	146,194
53	Marys Lake		Reclamation	Conventional Hydro	8.1	37,662
54	Estes		Reclamation	Conventional Hydro	45	100,440
55	Mount Elbert		Reclamation	Pumped Storage	200	
56	Pilot Butte		Reclamation	Conventional Hydro	1.6	3,016
57	Pole Hill		Reclamation	Conventional Hydro	38.2	17,6485
58	Seminoe		Reclamation	Conventional Hydro	51.6	136,810
WAPA-3 Salt Lake City & Provo River						
59	Blue Mesa	Salt Lake City	Reclamation	Conventional Hydro	86.4	266,427
60	Crystal		Reclamation	Conventional Hydro	28	168,470
61	Elephant Butte		Reclamation	Conventional Hydro	27.9	83,948
62	Flaming Gorge		Reclamation	Conventional Hydro	151.8	491,641
63	Fontenelle		Reclamation	Conventional Hydro	10	52,661
64	Glen Canyon Dam		Reclamation	Conventional Hydro	1312	4,595,940
65	Upper Molina		Reclamation	Conventional Hydro	8.6	31,230
66	Lower Molina		Reclamation	Conventional Hydro	4.8	18,137
67	McPhee		Reclamation	Conventional Hydro	1.2	3,291
68	Towaoc		Reclamation	Conventional Hydro	11.4	13,729
69	Morrow Point		Reclamation	Conventional Hydro	173.2	348,212
70	Deer Creek	Provo River	Reclamation	Conventional Hydro	4.8	24,824
WAPA-4 Boulder Canyon & Parker-Davis						
71	Hoover Dam	Boulder Canyon	Reclamation	Conventional Hydro	2078.8	4,590,049
72	Davis Dam	Parker-Davis	Reclamation	Conventional Hydro	254.8	1,175,312
73	Parker Dam		Reclamation	Conventional Hydro	120	518,890
WAPA-5 Falcon-Amistad						
74	Amistad Dam & Power	Falcon-Amistad	IBWC	Conventional Hydro	66	138,005
75	Falcon Dam & Power		IBWC	Conventional Hydro	31.5	81,057
WAPA-6 Central Valley & Washoe						
76	Folsom	Central Valley	Reclamation	Conventional Hydro	198.6	601,560
77	Judge F Carr		Reclamation	Conventional Hydro	154.4	482,209
78	Keswick		Reclamation	Conventional Hydro	117	450,888
79	New Melones		Reclamation	Conventional Hydro	300	439,555
80	Nimbus		Reclamation	Conventional Hydro	13.4	61,831
81	ONeill		Reclamation	Pumped Storage	25.2	
82	W R Gianelli		Reclamation	Pumped Storage	424	
83	Shasta		Reclamation	Conventional Hydro	697	1,939,589
84	Spring Creek		Reclamation	Conventional Hydro	180	588,273
85	Trinity		Reclamation	Conventional Hydro	140	474,789
86	Stampede	Washoe	Reclamation	Conventional Hydro	3.6	9,808
SWPA-1 Upper White, Osage & Salt						
87	Beaver	Southwestern financially integrated projects	USACE	Conventional Hydro	112	154,432
88	Bull Shoals		USACE	Conventional Hydro	340	771,563
89	Clarence Cannon		USACE	Conventional Hydro	27	89,850
				Pumped Storage[b]	31	
90	Greers Ferry		USACE	Conventional Hydro	96	189,101
91	Harry S Truman		USACE	Pumped Storage[c]	160	254,989
92	Norfork		USACE	Conventional Hydro	80.5	200,453
93	Stockton		USACE	Conventional Hydro	45.2	56,506
94	Table Rock		USACE	Conventional Hydro	200	531,238
SWPA-2 Arkansas						
95	Dardanelle	Southwestern financially integrated projects	USACE	Conventional Hydro	140	637,730
96	Eufaula		USACE	Conventional Hydro	90	280,370
97	Fort Gibson		USACE	Conventional Hydro	45	224,176
98	Keystone		USACE	Conventional Hydro	70	281,136
99	Ozark		USACE	Conventional Hydro	100	293,981
100	Robert S Kerr		USACE	Conventional Hydro	110	575,576
101	Tenkiller Ferry		USACE	Conventional Hydro	39.1	124,589
102	Webbers Falls		USACE	Conventional Hydro	60	215,942

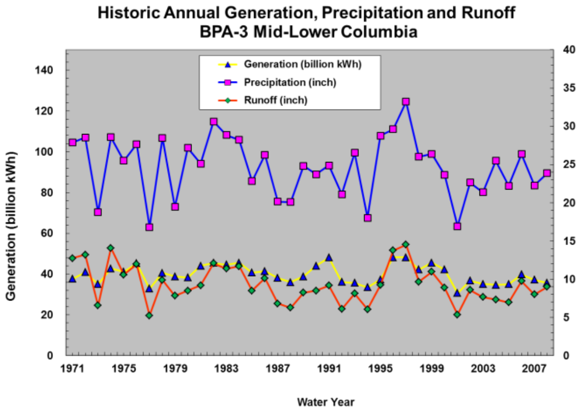
N	Power plant name	Power system	Owner	Generation type	Capacity (MW)	FY 1971–FY 2008 average annual generation (thousand kWh/year)
103	Broken Bow		USACE	Conventional Hydro	100	157,474
SWPA-3 Ouachita, Red & Brazos						
104	Blakely Mountain	Southwestern financially integrated projects	USACE	Conventional Hydro	75	186,893
105	DeGray		USACE	Conventional Hydro	40	83,189
				Pumped Storage (Reversible)	28	
106	Denison		USACE	Conventional Hydro	70	260,283
107	Narrows		USACE	Conventional Hydro	25.5	38,294
108	Whitney		USACE	Conventional Hydro	30	54,120
SWPA-4 *Neches*						
109	Robert D Willis	Southwestern isolated projects	USACE	Conventional Hydro	7.4	29639
110	Sam Rayburn		USACE	Conventional Hydro	52	125487
SEPA-1 Kerr-Philpot						
111	John H Kerr	Kerr-Philpot	USACE	Conventional Hydro	267	437,400
112	Philpott Lake		USACE	Conventional Hydro	15	25,600
SEPA-2 Cumberland						
113	Barkley	Cumberland	USACE	Conventional Hydro	148	584,000
114	Center Hill		USACE	Conventional Hydro	156	377,000
115	Cheatham		USACE	Conventional Hydro	41	160,000
116	Cordell Hull		USACE	Conventional Hydro	114	354,000
117	Dale Hollow		USACE	Conventional Hydro	62	123,000
118	J P Priest		USACE	Conventional Hydro	30	73,000
119	Laurel		USACE	Conventional Hydro	70	65,000
120	Old Hickory		USACE	Conventional Hydro	116	469,000
121	Wolf Creek		USACE	Conventional Hydro	312	915,000
SEPA-3 GA-AL-SC						
122	Allatoona	GA-AL-SC	USACE	Conventional Hydro	82	151,000
123	Buford		USACE	Conventional Hydro	127	186,000
124	Carters		USACE	Conventional Hydro	286	405,000
				Pumped Storage	320	
125	Hartwell Lake		USACE	Conventional Hydro	432	470,000
126	J Strom Thurmond		USACE	Conventional Hydro	364	707,000
127	Millers Ferry		USACE	Conventional Hydro	90	384,000
128	Jones Bluff		USACE	Conventional Hydro	82	335,000
129	Richard B Russell		USACE	Conventional Hydro	336	685,000
				Pumped Storage	328	
130	Walter F George		USACE	Conventional Hydro	163	438,000
131	West Point		USACE	Conventional Hydro	87	202,000
SEPA-4 Jim Woodruff						
132	J Woodruff	Jim Woodruff	USACE	Conventional Hydro	43	237,000

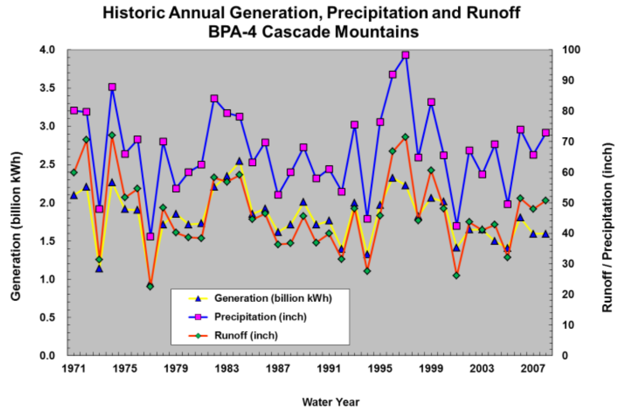
[a] Two of the four Yellowtail units are marketed as a Pick-Sloan-Eastern Division resource and two are marketed as a Loveland Area Projects resource. For the purposes of this analysis, the entire Yellowtail plant is included in the Pick-Sloan-Eastern Division.
[b] The pumpback feature of the reversible unit at Cannon has not been used in regular operation (other than initial tests). As the reservoir has to be significantly low for the pumpback to function, it has not been practice to use the feature. The reversible unit is used regularly like conventional hydro.
[c] Although Harry S. Truman has the capability of pumped storage through multiple reversible units, it is used as conventional hydro because of state objections to the use of the pumpback function. It is currently not available as a pumped storage project.

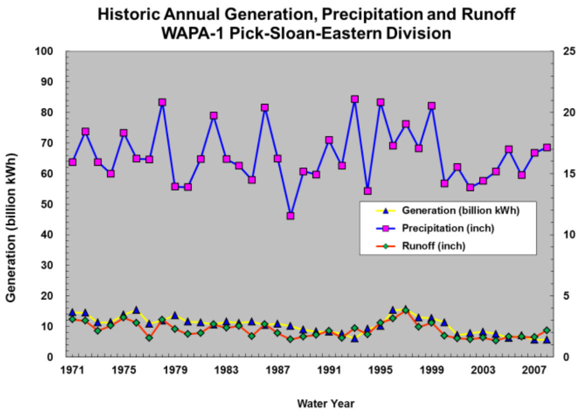
APPENDIX C. ANNUAL PRECIPITATION, RUNOFF, AND GENERATION FOR EACH OF THE PMA ASSESSMENT AREAS

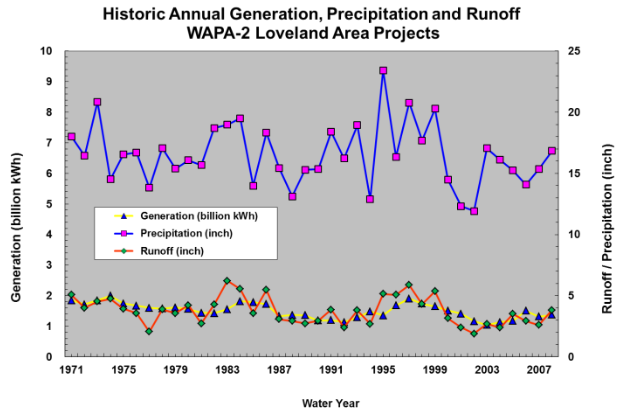


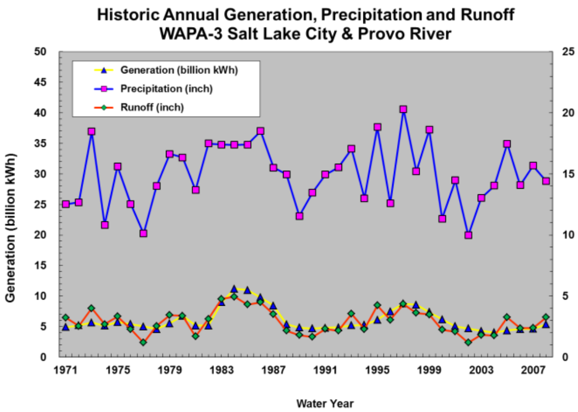


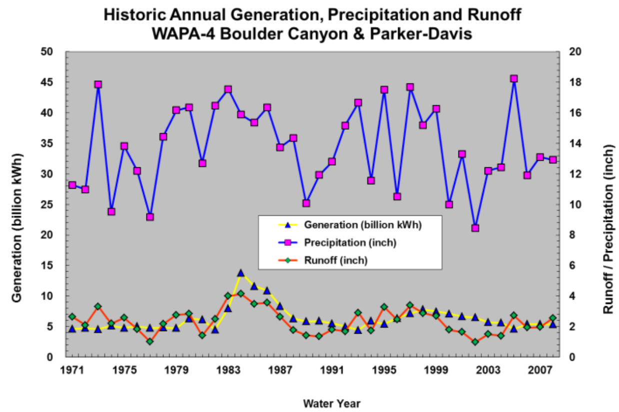


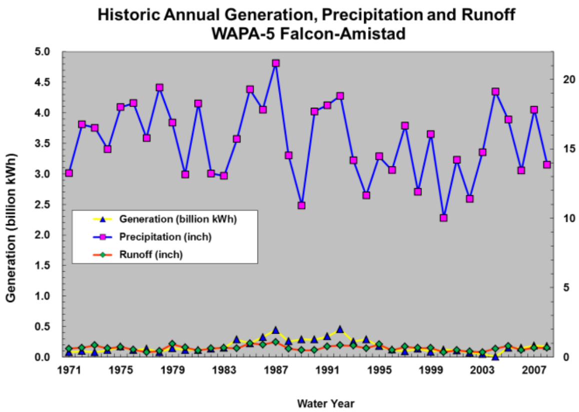


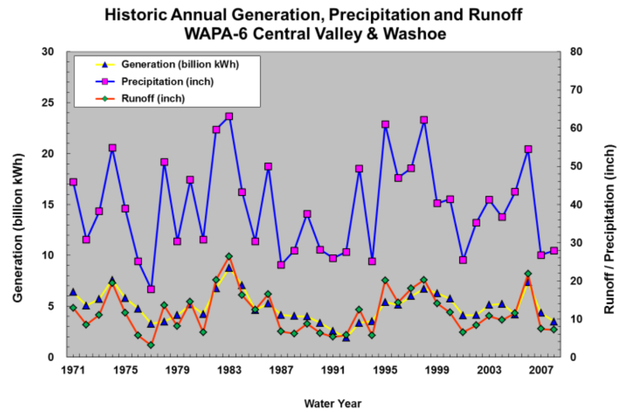


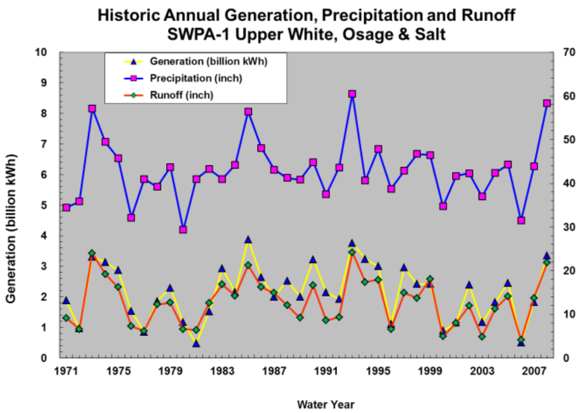


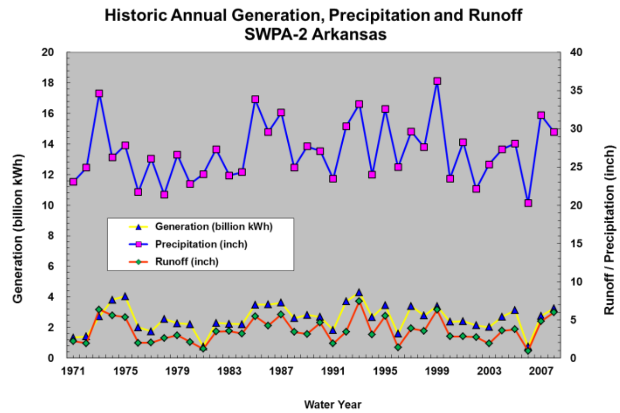

Historic Annual Generation, Precipitation and Runoff
WAPA-3 Salt Lake City & Provo River
Generation (billion kWh)
Precipitation (inch)
Runoff (inch)
Generation (billion kWh)
Runoff / Precipitation (inch)
Water Year


Historic Annual Generation, Precipitation and Runoff
WAPA-4 Boulder Canyon & Parker-Davis
Generation (billion kWh)
Precipitation (inch)
Runoff (inch)
Generation (billion kWh)
Runoff / Precipitation (inch)
Water Year

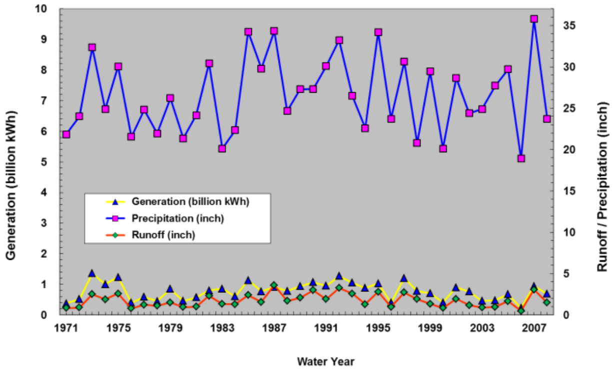

Historic Annual Generation, Precipitation and Runoff
WAPA-5 Falcon-Amistad
Generation (billion kWh)
Precipitation (inch)
Runoff (inch)
Generation (billion kWh)
Runoff / Precipitation (inch)
Water Year


Historic Annual Generation, Precipitation and Runoff
WAPA-6 Central Valley & Washoe
Generation (billion kWh)
Precipitation (inch)
Runoff (inch)
Generation (billion kWh)
Runoff / Precipitation (inch)
Water Year

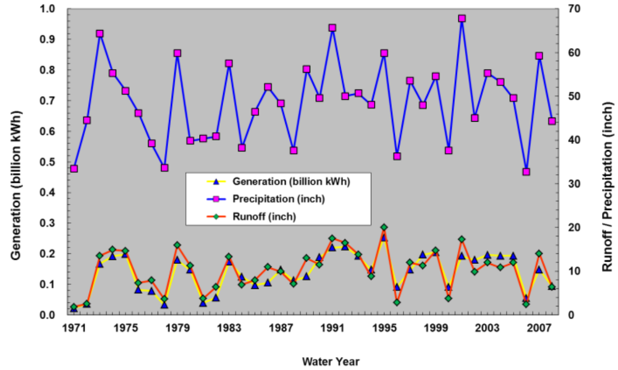

Historic Annual Generation, Precipitation and Runoff
SWPA-1 Upper White, Osage & Salt
Generation (billion kWh)
Precipitation (inch)
Runoff (inch)
Generation (billion kWh)
Runoff / Precipitation (inch)
Water Year


Historic Annual Generation, Precipitation and Runoff
SWPA-2 Arkansas
Generation (billion kWh)
Precipitation (inch)
Runoff (inch)
Generation (billion kWh)
Runoff / Precipitation (inch)
Water Year

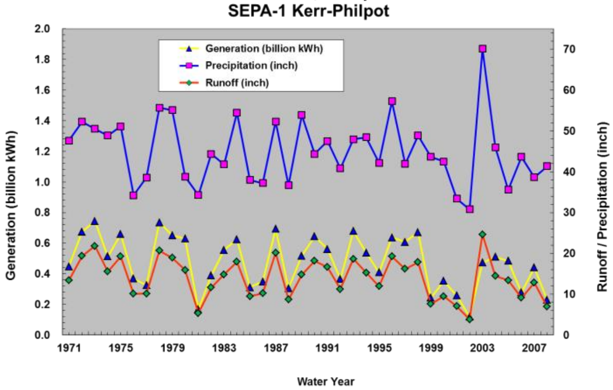
Historic Annual Generation, Precipitation and Runoff
SWPA-3 Ouachita, Red & Brazos



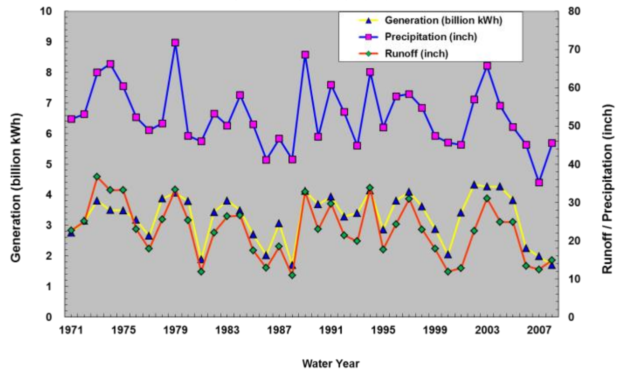
Historic Annual Generation, Precipitation and Runoff
SWPA-4 Neches



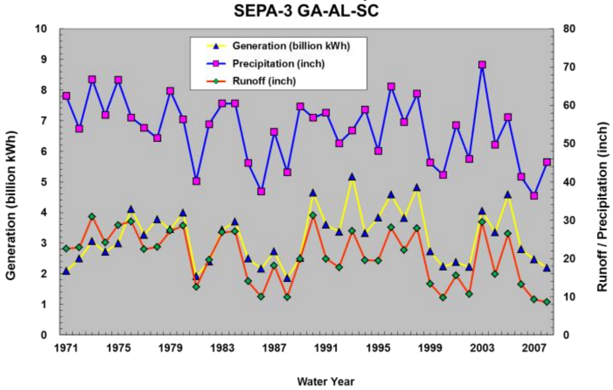
Historic Annual Generation, Precipitation and Runoff
SEPA-1 Kerr-Philpot



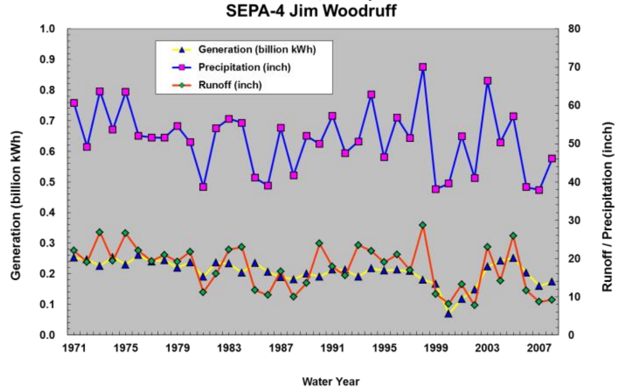
Historic Annual Generation, Precipitation and Runoff
SEPA-2 Cumberland



Historic Annual Generation, Precipitation and Runoff
SEPA-3 GA-AL-SC

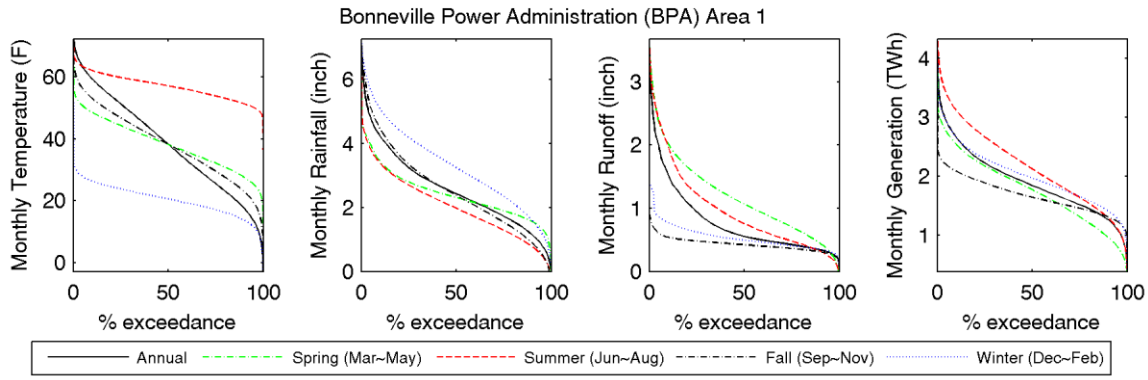


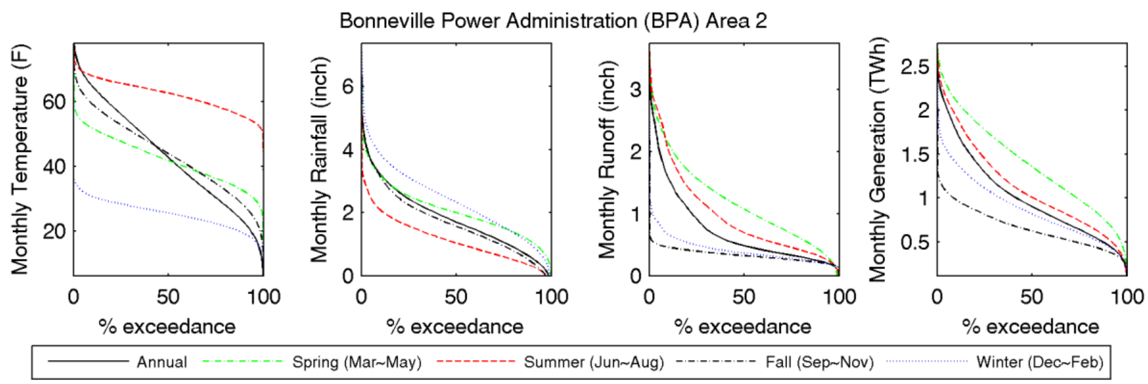
Historic Annual Generation, Precipitation and Runoff
SEPA-4 Jim Woodruff

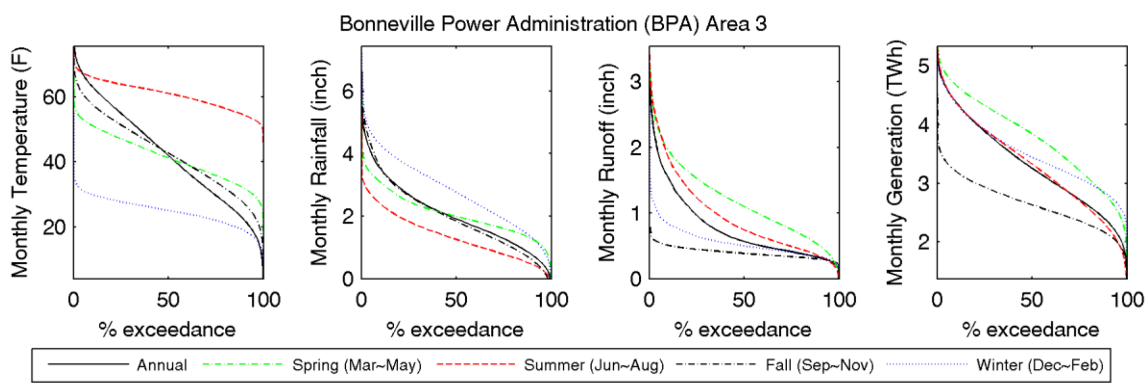


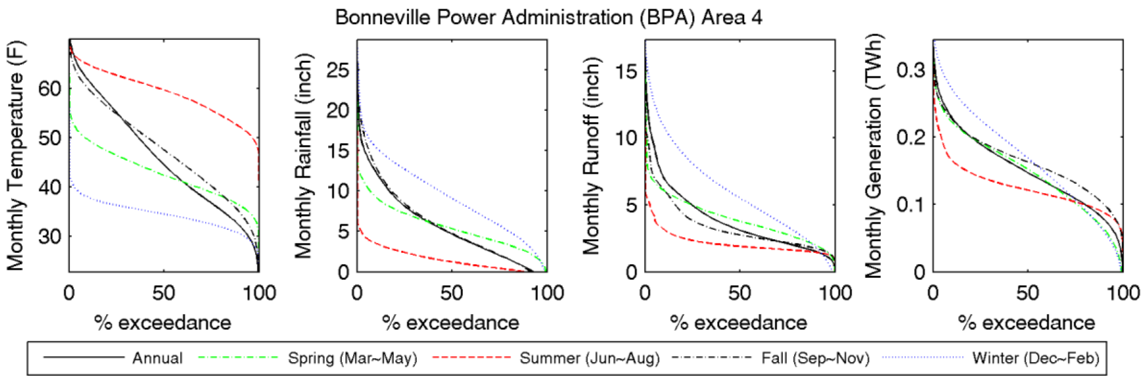
APPENDIX D. CUMULATIVE DISTRIBUTIONS OF MONTHLY TEMPERATURE, RAINFALL, RUNOFF, AND GENERATION

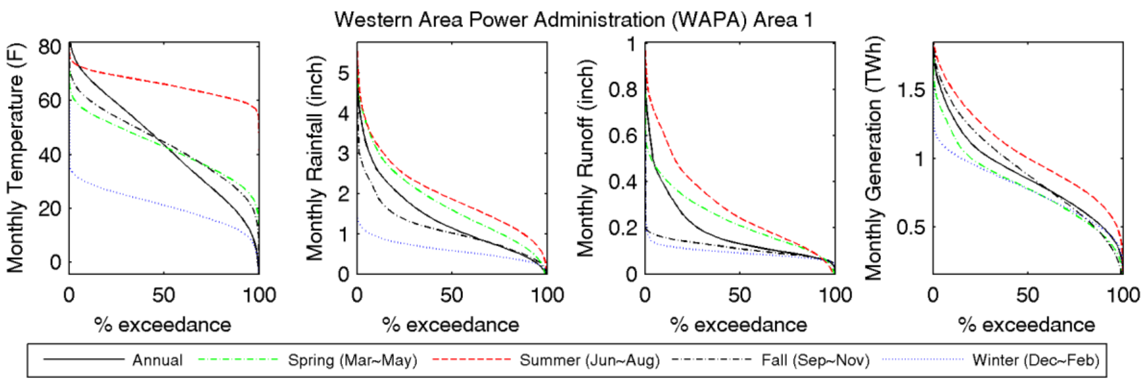
The graphs illustrate cumulative distributions of observed monthly temperature, rainfall, runoff, and generation. Solid black lines represent distribution curves across the entire year; dashed green lines, March–May, dashed red lines, June–August; dashed black lines, September—November; and dotted blue lines, December–February.

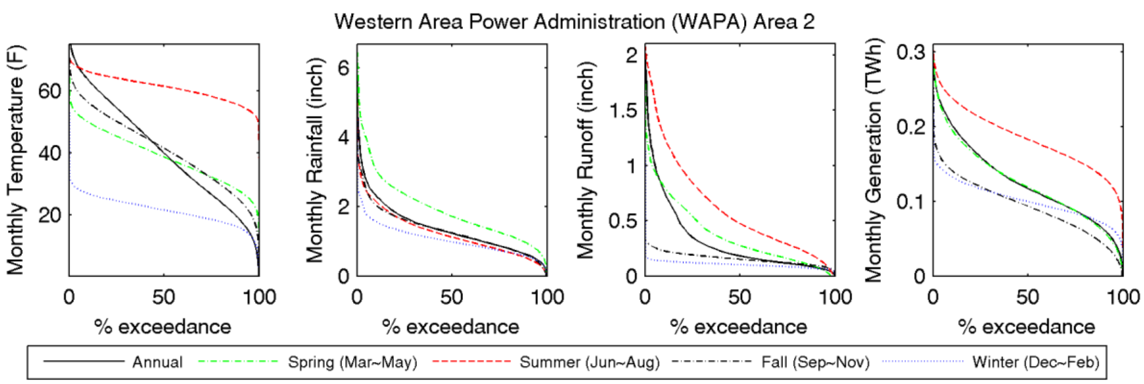


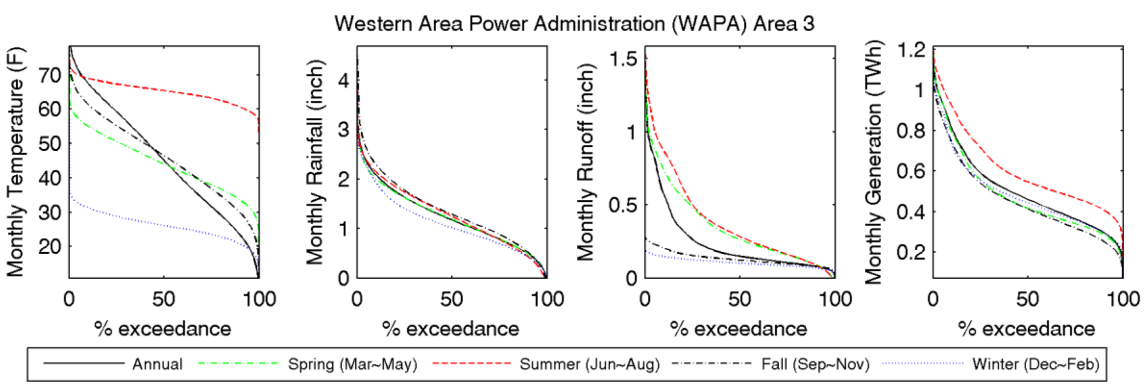


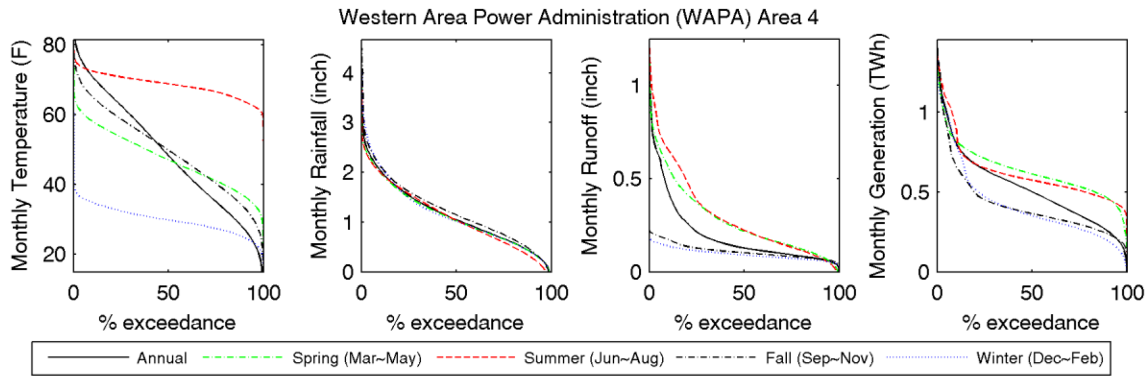


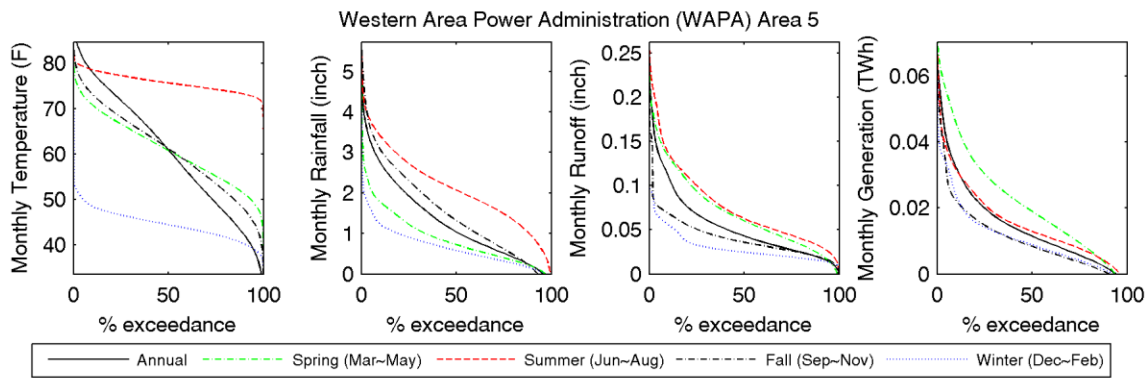

Bonneville Power Administration (BPA) Area 4
Monthly Temperature (F)
Monthly Rainfall (inch)
Monthly Runoff (inch)
Monthly Generation (TWh)
% exceedance
Annual
Spring (Mar~May)
Summer (Jun~Aug)
Fall (Sep~Nov)
Winter (Dec~Feb)

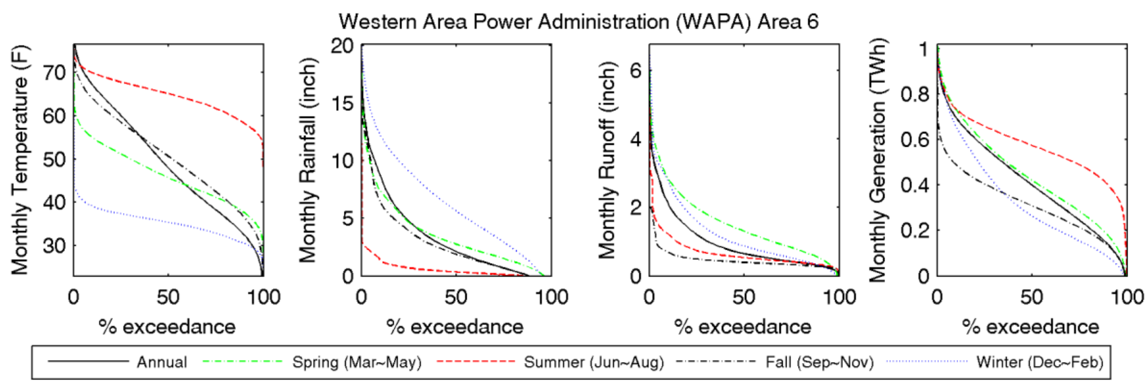

Western Area Power Administration (WAPA) Area 1
Monthly Temperature (F)
Monthly Rainfall (inch)
Monthly Runoff (inch)
Monthly Generation (TWh)
% exceedance
Annual
Spring (Mar~May)
Summer (Jun~Aug)
Fall (Sep~Nov)
Winter (Dec~Feb)

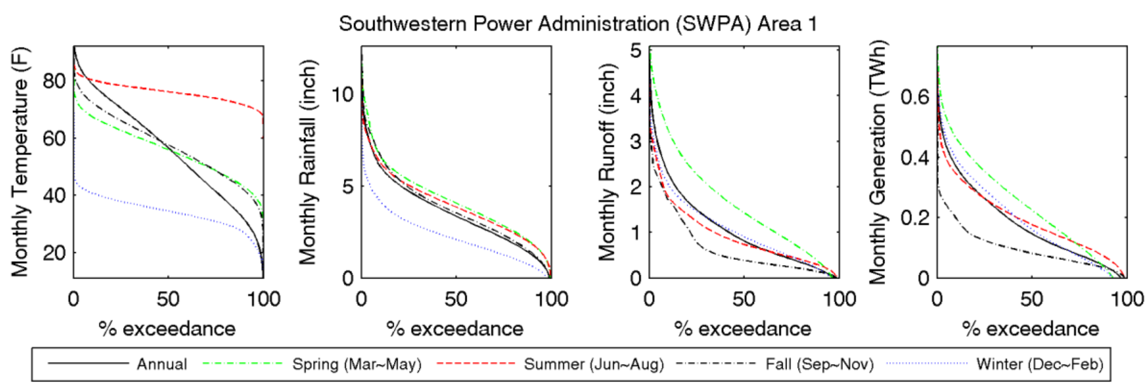

Western Area Power Administration (WAPA) Area 2
Monthly Temperature (F)
Monthly Rainfall (inch)
Monthly Runoff (inch)
Monthly Generation (TWh)
% exceedance
Annual
Spring (Mar~May)
Summer (Jun~Aug)
Fall (Sep~Nov)
Winter (Dec~Feb)


Western Area Power Administration (WAPA) Area 3
Monthly Temperature (F)
Monthly Rainfall (inch)
Monthly Runoff (inch)
Monthly Generation (TWh)
% exceedance
Annual
Spring (Mar~May)
Summer (Jun~Aug)
Fall (Sep~Nov)
Winter (Dec~Feb)

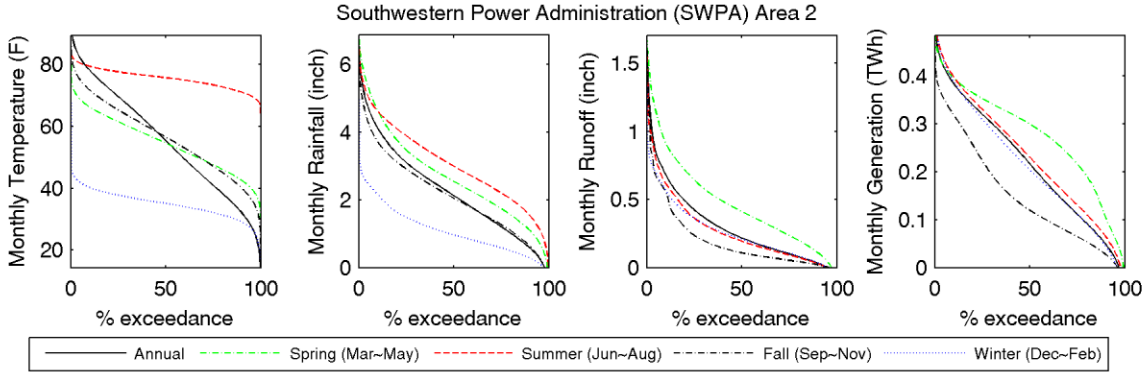

Western Area Power Administration (WAPA) Area 4
Monthly Temperature (F)
Monthly Rainfall (inch)
Monthly Runoff (inch)
Monthly Generation (TWh)
% exceedance
Annual
Spring (Mar~May)
Summer (Jun~Aug)
Fall (Sep~Nov)
Winter (Dec~Feb)


Western Area Power Administration (WAPA) Area 5
Monthly Temperature (F)
Monthly Rainfall (inch)
Monthly Runoff (inch)
Monthly Generation (TWh)
% exceedance
Annual
Spring (Mar~May)
Summer (Jun~Aug)
Fall (Sep~Nov)
Winter (Dec~Feb)

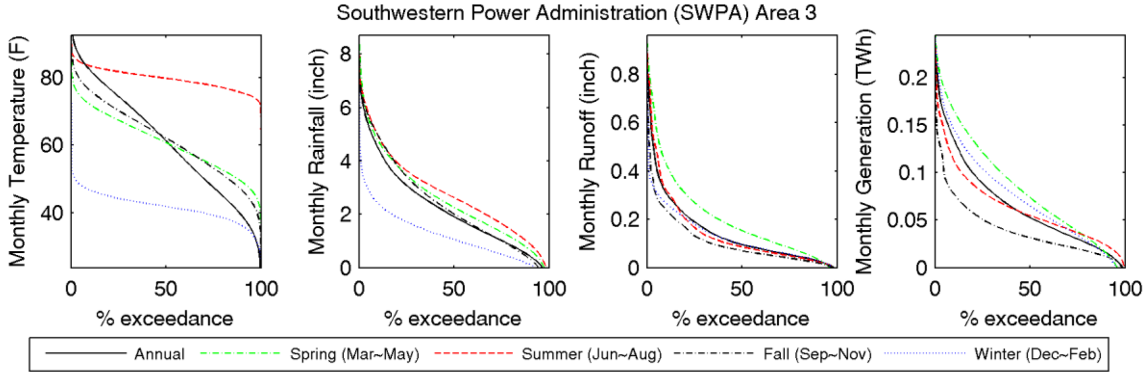

Western Area Power Administration (WAPA) Area 6
Monthly Temperature (F)
Monthly Rainfall (inch)
Monthly Runoff (inch)
Monthly Generation (TWh)
% exceedance
Annual
Spring (Mar~May)
Summer (Jun~Aug)
Fall (Sep~Nov)
Winter (Dec~Feb)


Southwestern Power Administration (SWPA) Area 1
Monthly Temperature (F)
Monthly Rainfall (inch)
Monthly Runoff (inch)
Monthly Generation (TWh)
% exceedance
Annual
Spring (Mar~May)
Summer (Jun~Aug)
Fall (Sep~Nov)
Winter (Dec~Feb)

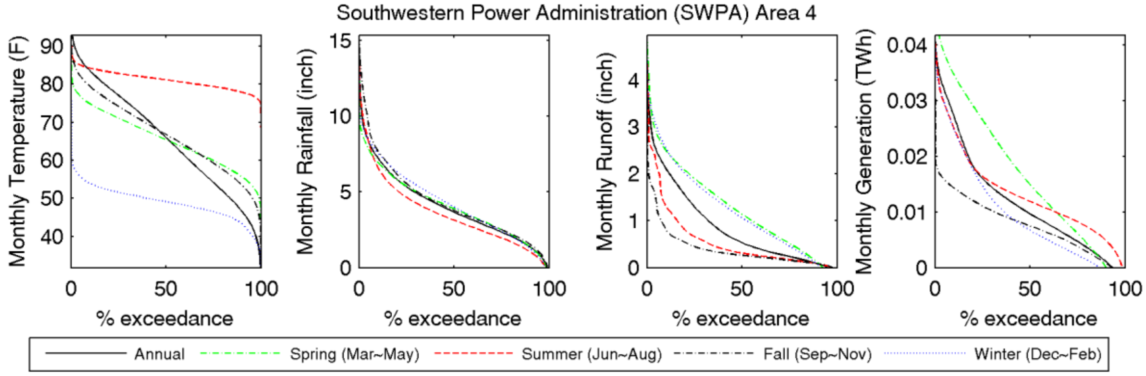
Southwestern Power Administration (SWPA) Area 2



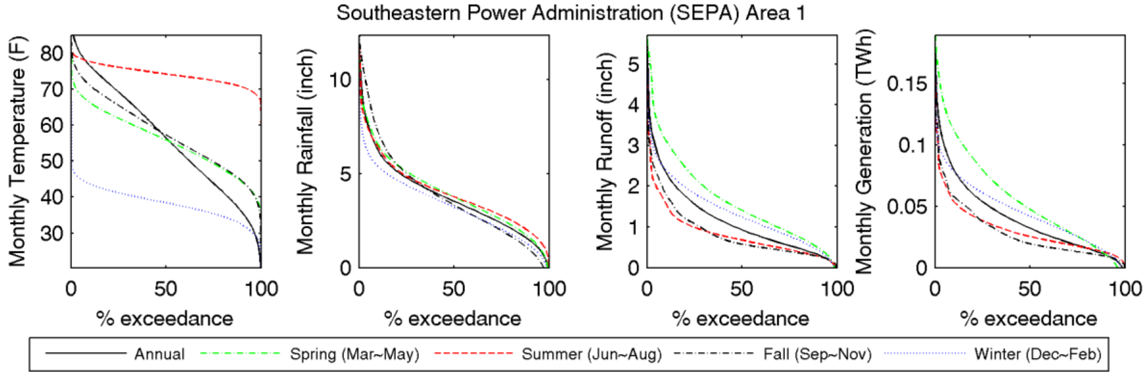
Southwestern Power Administration (SWPA) Area 3

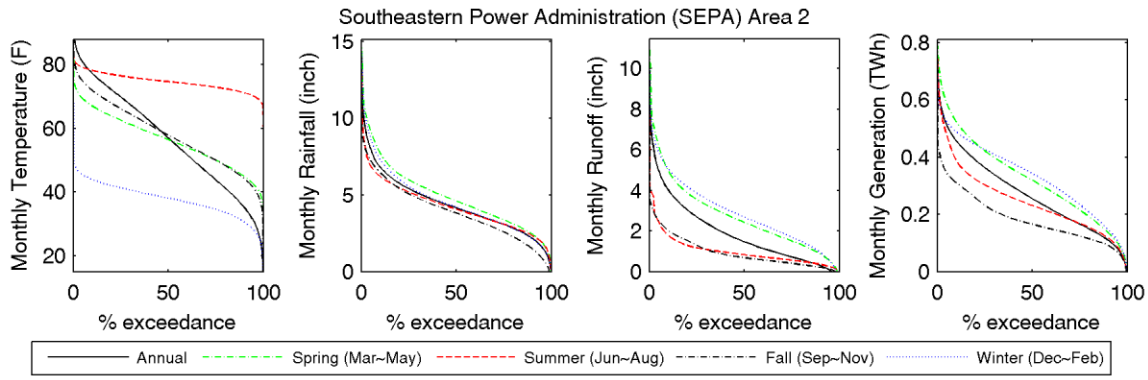


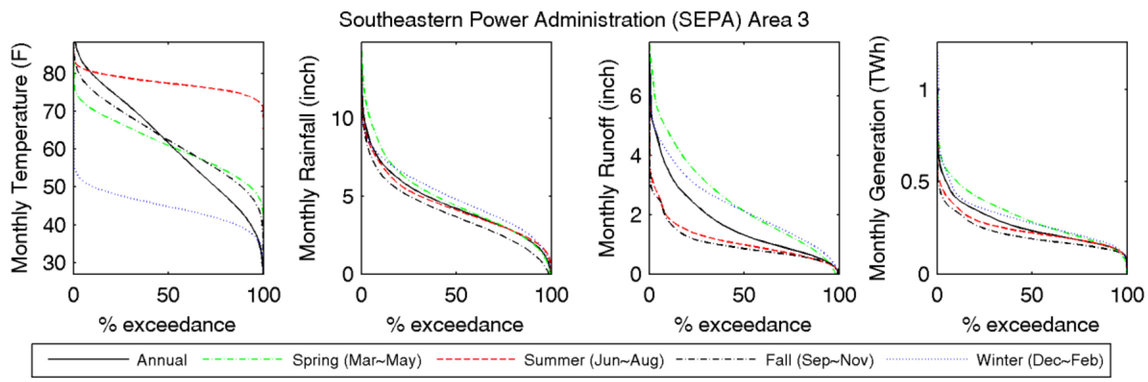
Southwestern Power Administration (SWPA) Area 4

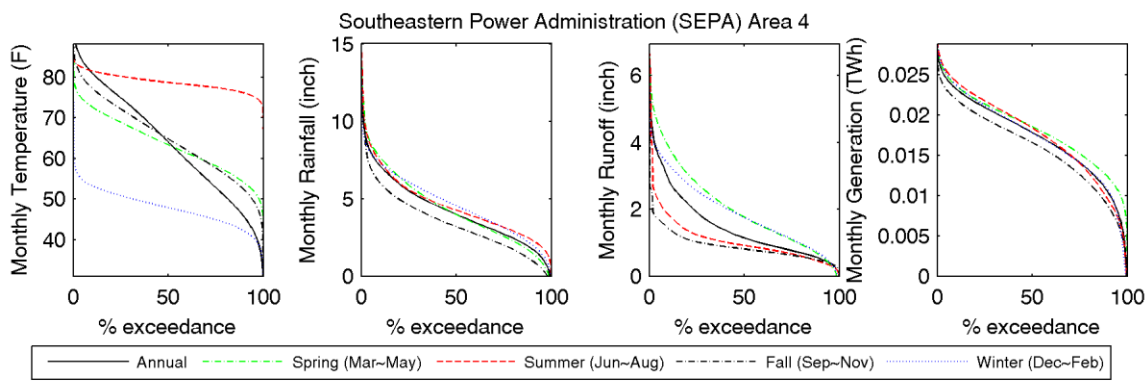


Southeastern Power Administration (SEPA) Area 1

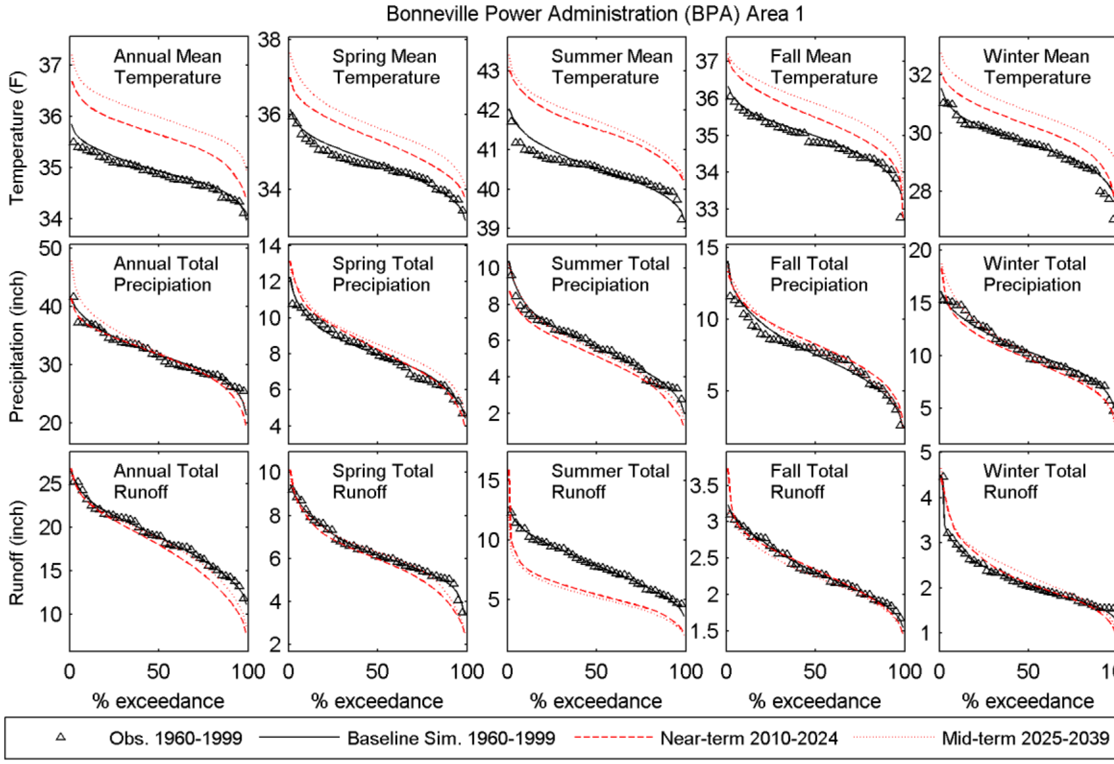


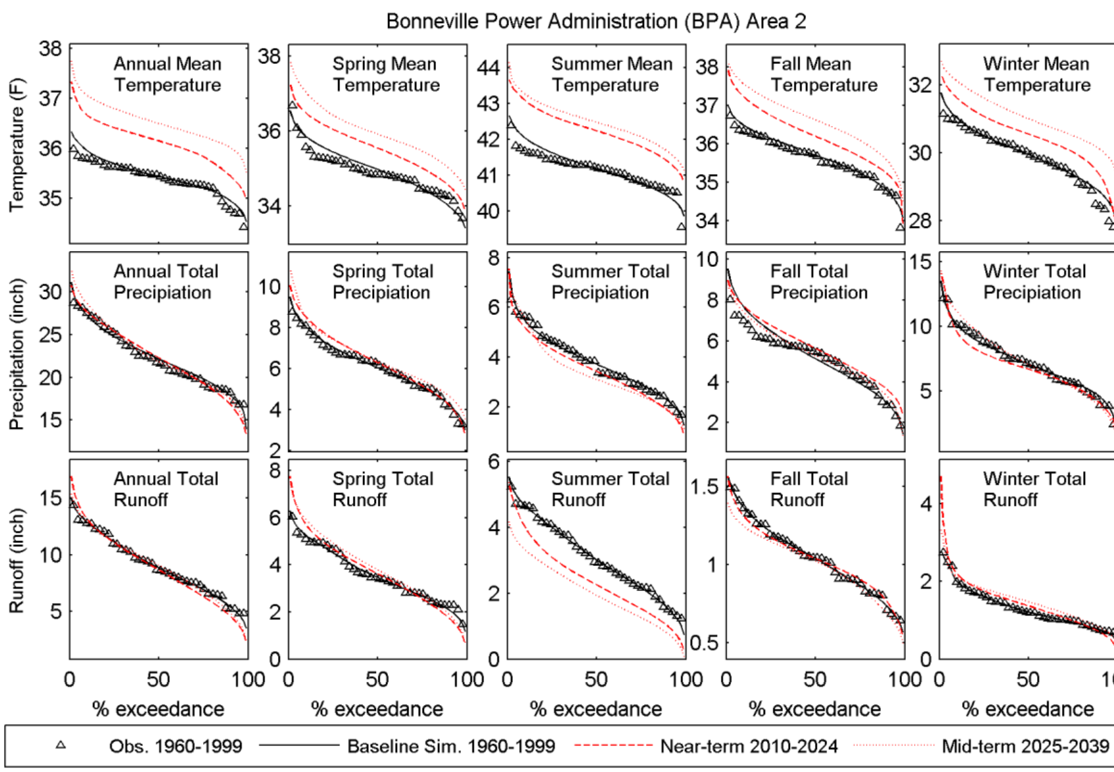

Southeastern Power Administration (SEPA) Area 2
Monthly Temperature (F)
Monthly Rainfall (inch)
Monthly Runoff (inch)
Monthly Generation (TWh)
% exceedance
Annual
Spring (Mar~May)
Summer (Jun~Aug)
Fall (Sep~Nov)
Winter (Dec~Feb)

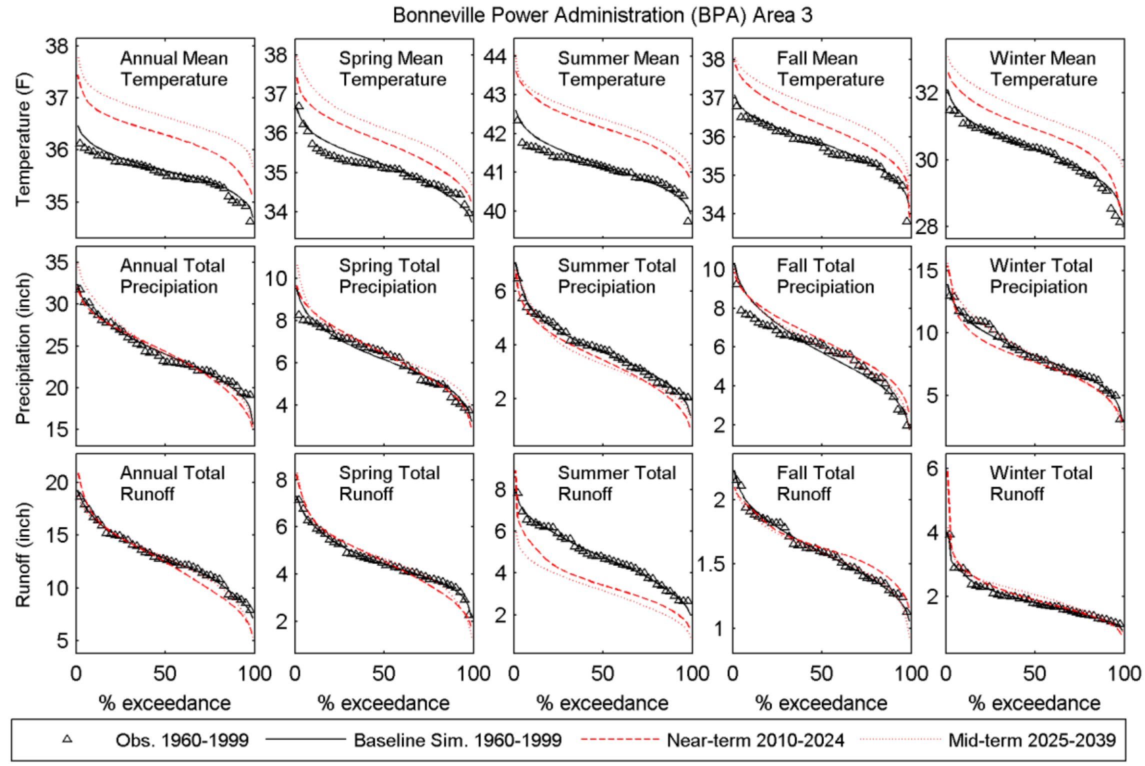

Southeastern Power Administration (SEPA) Area 3
Monthly Temperature (F)
Monthly Rainfall (inch)
Monthly Runoff (inch)
Monthly Generation (TWh)
% exceedance
Annual
Spring (Mar~May)
Summer (Jun~Aug)
Fall (Sep~Nov)
Winter (Dec~Feb)

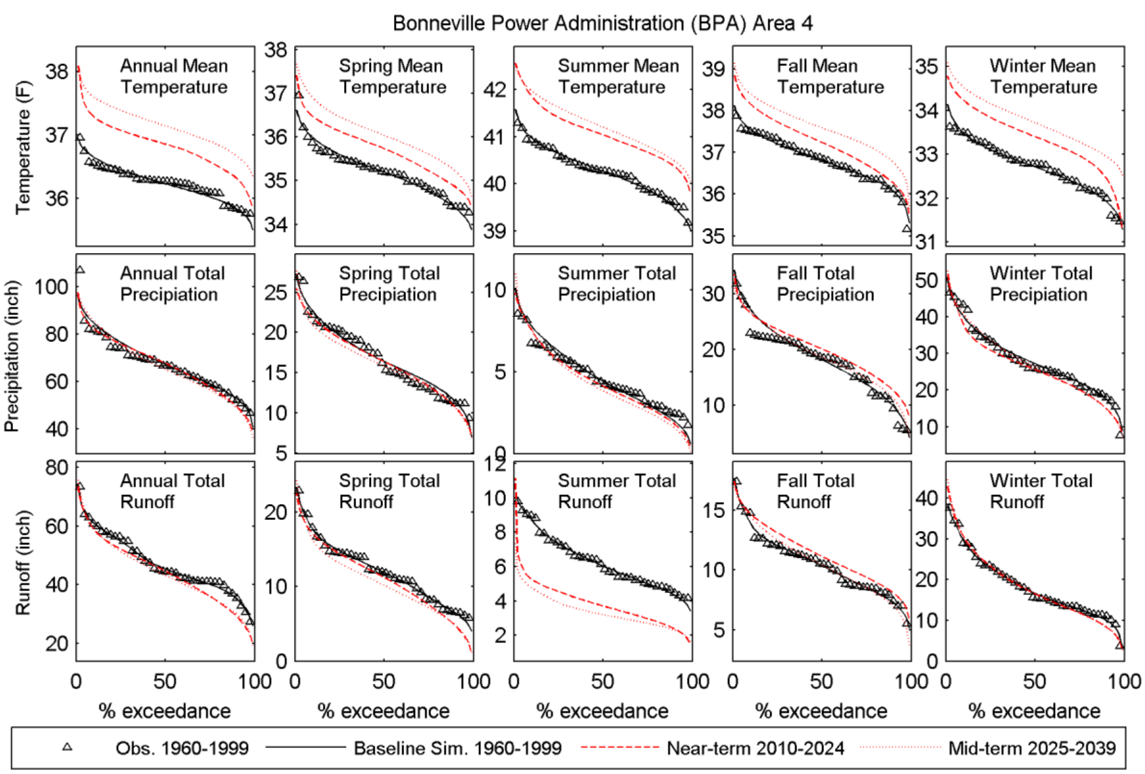

Southeastern Power Administration (SEPA) Area 4
Monthly Temperature (F)
Monthly Rainfall (inch)
Monthly Runoff (inch)
Monthly Generation (TWh)
% exceedance
Annual
Spring (Mar~May)
Summer (Jun~Aug)
Fall (Sep~Nov)
Winter (Dec~Feb)

APPENDIX E. CUMULATIVE DISTRIBUTIONS OF OBSERVED AND SIMULATED TEMPERATURE, RAINFALL, AND RUNOFF

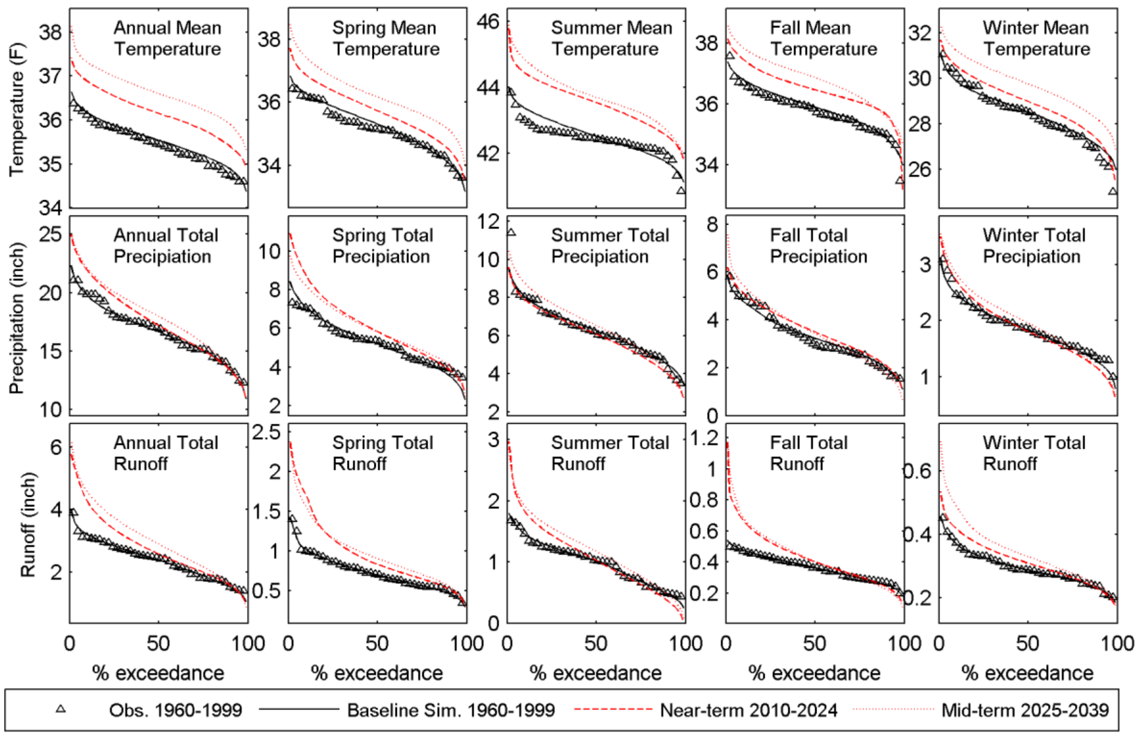




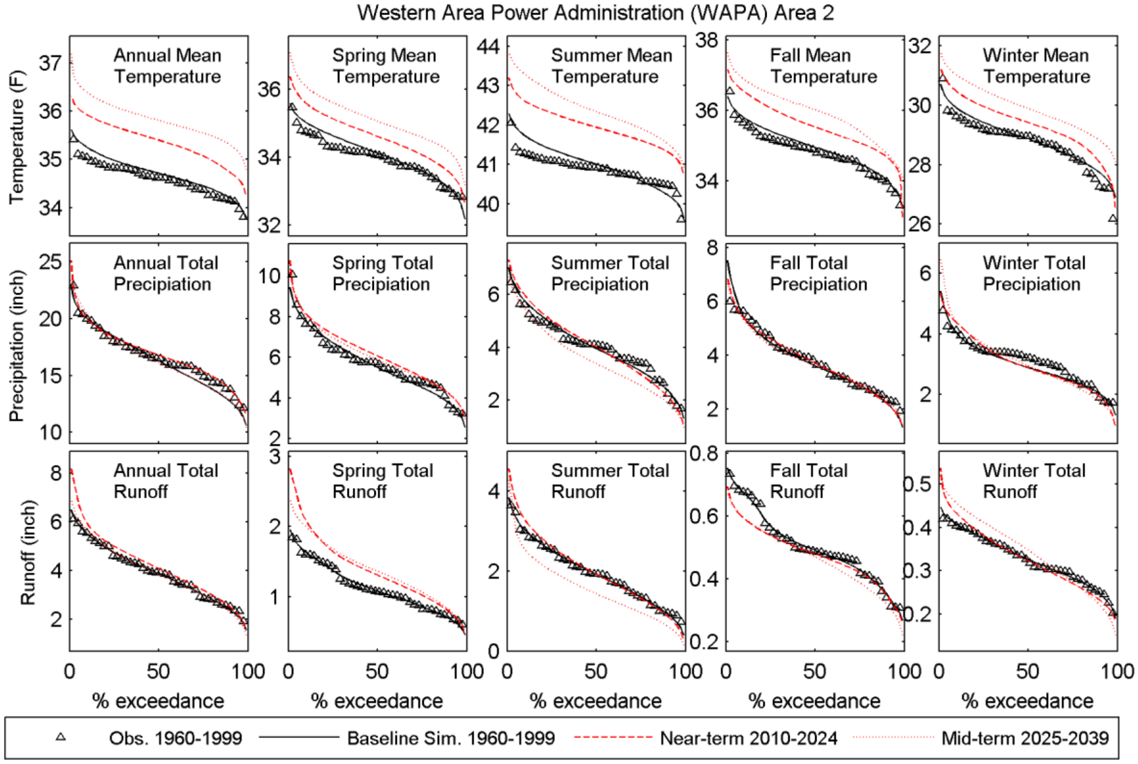

Bonneville Power Administration (BPA) Area 3
Annual Mean Temperature
Spring Mean Temperature
Summer Mean Temperature
Fall Mean Temperature
Winter Mean Temperature
Annual Total Precipitation
Spring Total Precipitation
Summer Total Precipitation
Fall Total Precipitation
Winter Total Precipitation
Annual Total Runoff
Spring Total Runoff
Summer Total Runoff
Fall Total Runoff
Winter Total Runoff
Temperature (F)
Precipitation (inch)
Runoff (inch)
% exceedance
Obs. 1960-1999
Baseline Sim. 1960-1999
Near-term 2010-2024
Mid-term 2025-2039


Bonneville Power Administration (BPA) Area 4
Annual Mean Temperature
Spring Mean Temperature
Summer Mean Temperature
Fall Mean Temperature
Winter Mean Temperature
Annual Total Precipitation
Spring Total Precipitation
Summer Total Precipitation
Fall Total Precipitation
Winter Total Precipitation
Annual Total Runoff
Spring Total Runoff
Summer Total Runoff
Fall Total Runoff
Winter Total Runoff
Temperature (F)
Precipitation (inch)
Runoff (inch)
% exceedance
Obs. 1960-1999
Baseline Sim. 1960-1999
Near-term 2010-2024
Mid-term 2025-2039

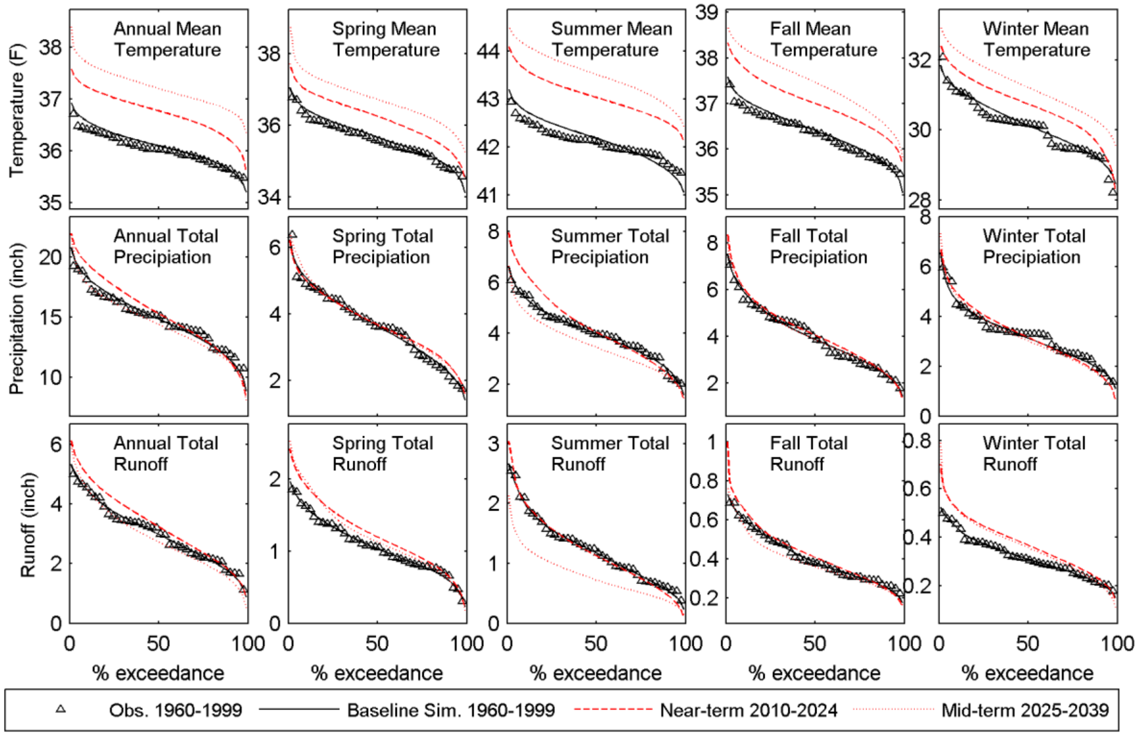
Western Area Power Administration (WAPA) Area 1



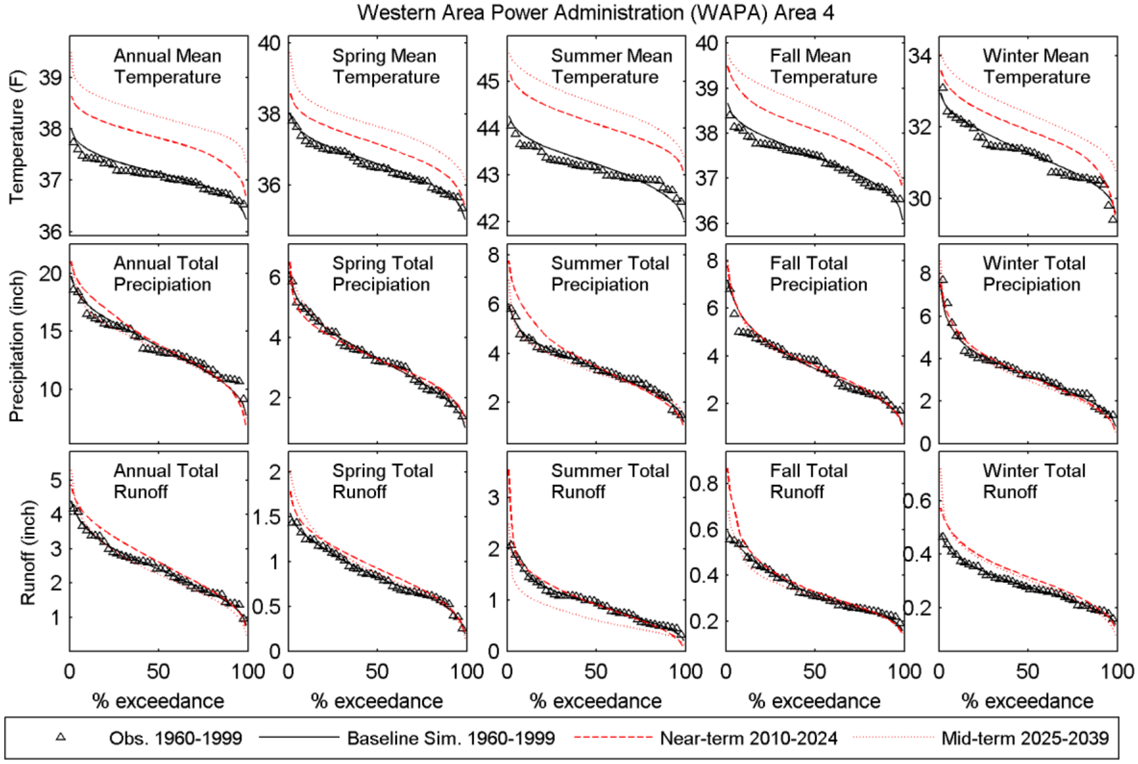
Western Area Power Administration (WAPA) Area 2

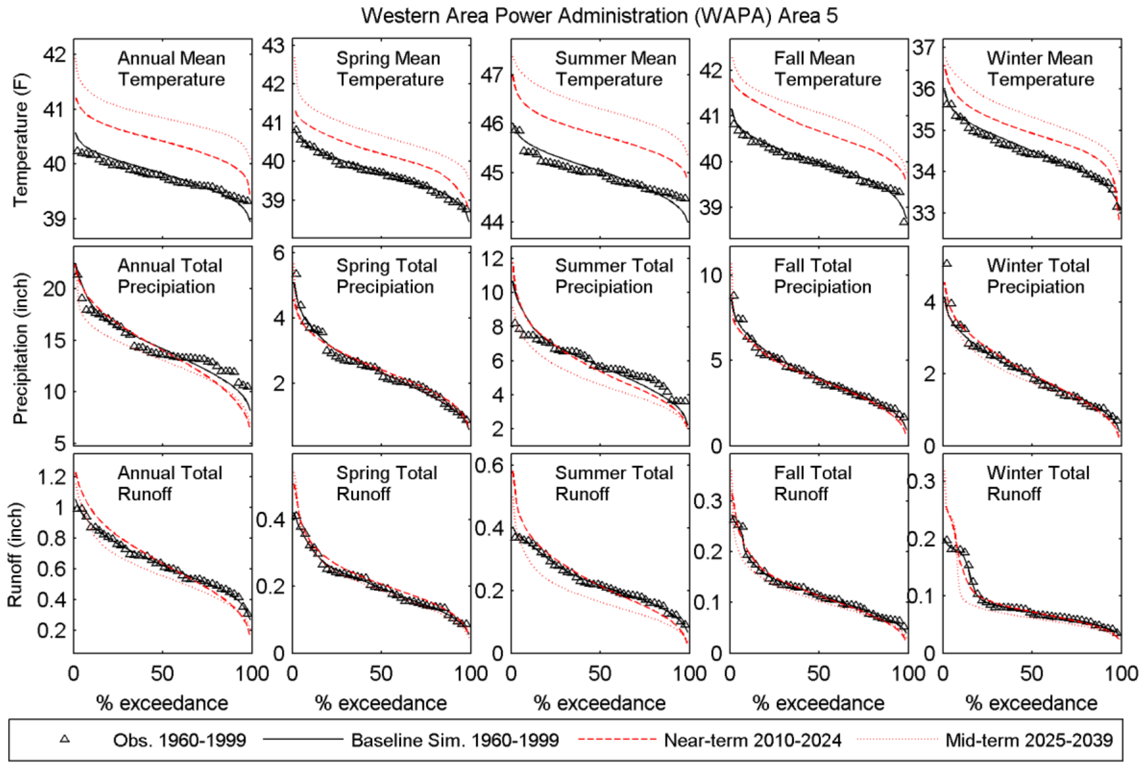


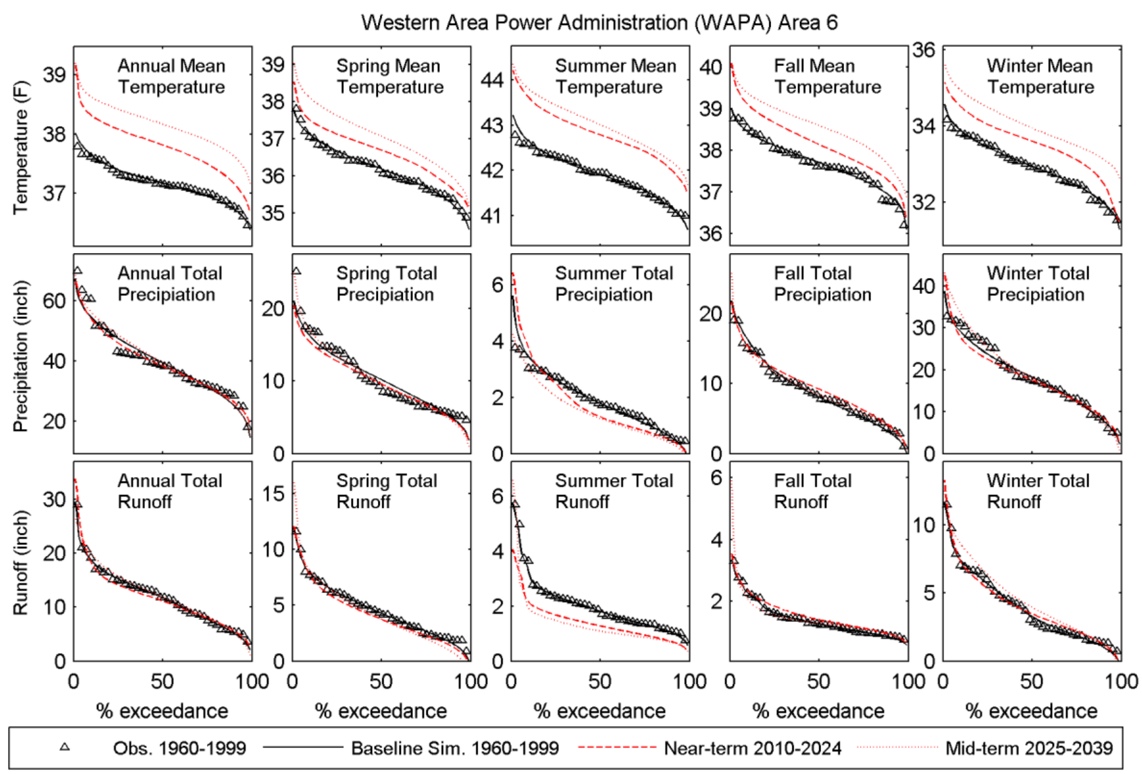
Western Area Power Administration (WAPA) Area 3

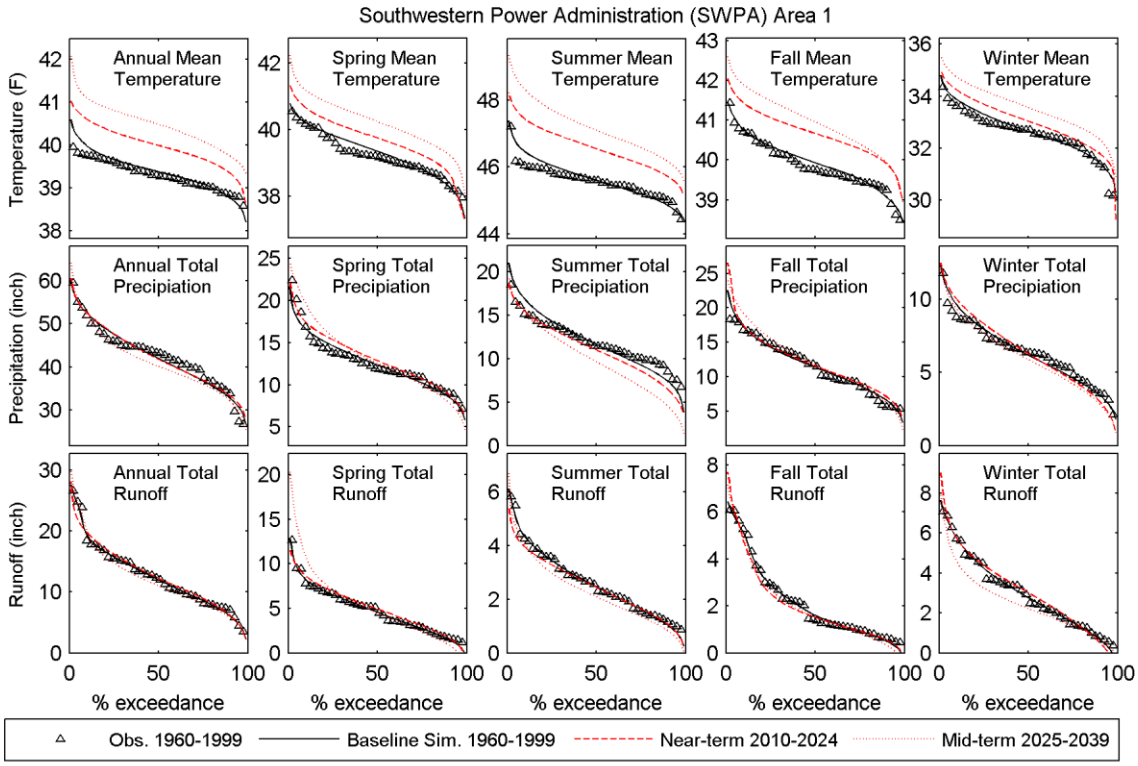


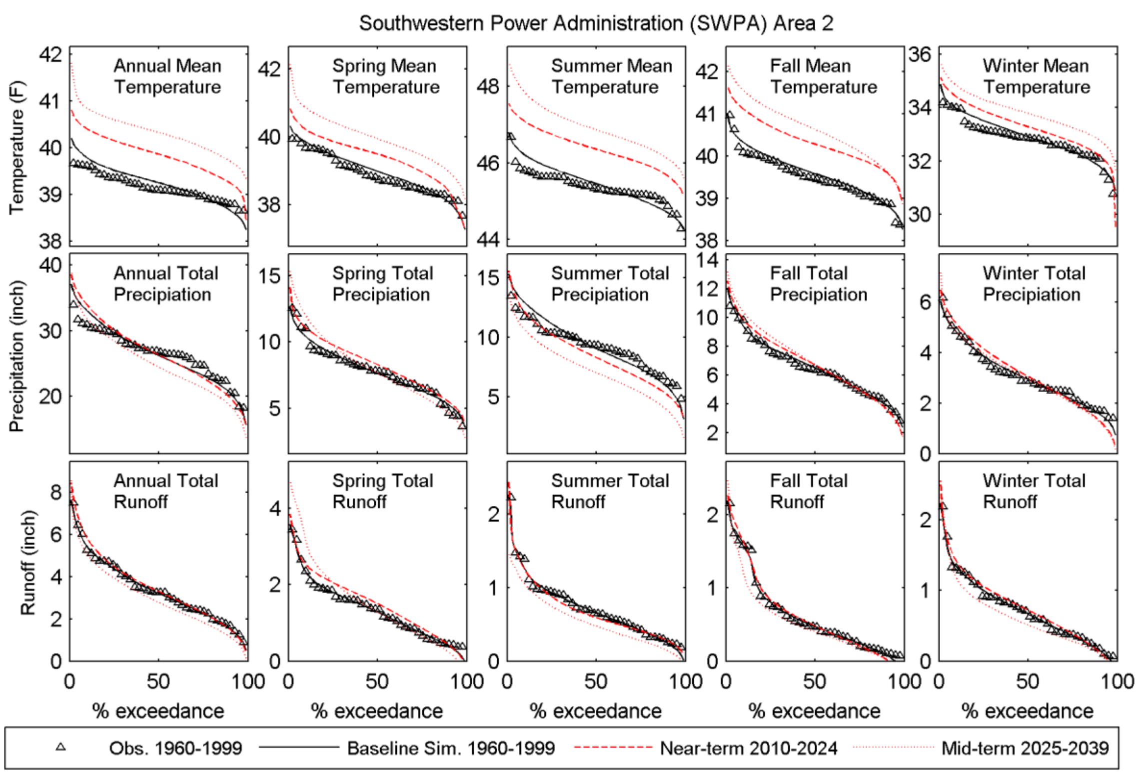
Western Area Power Administration (WAPA) Area 4

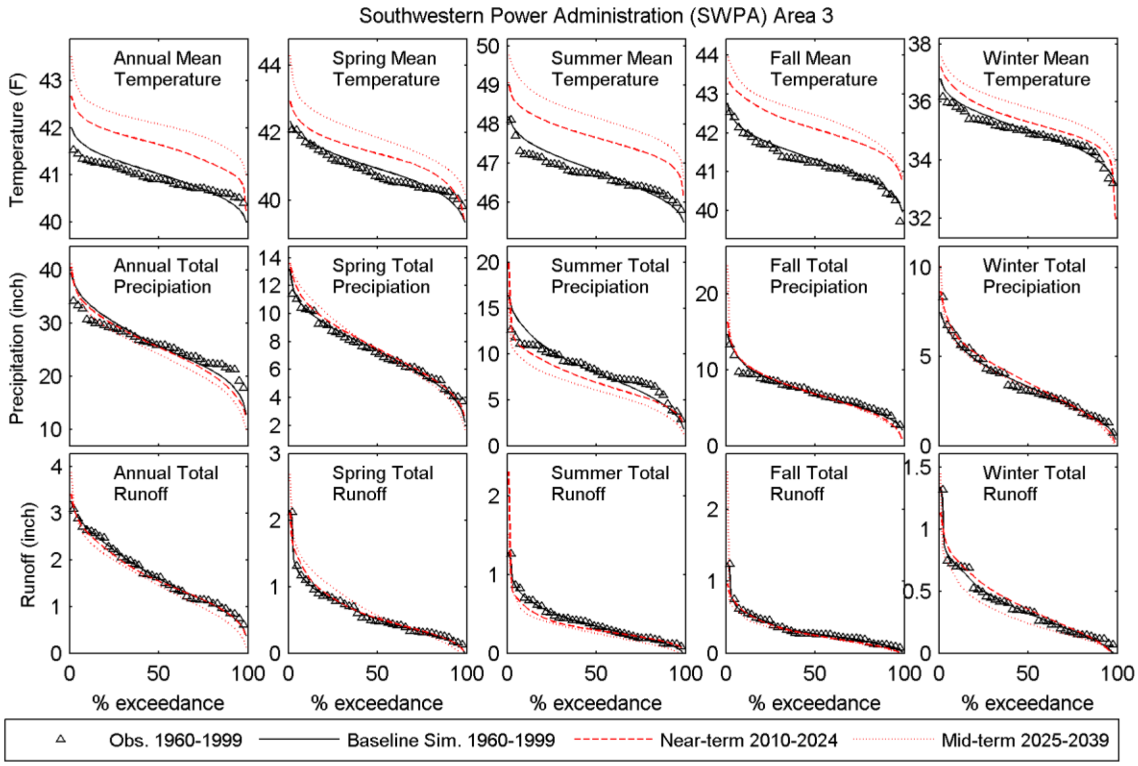


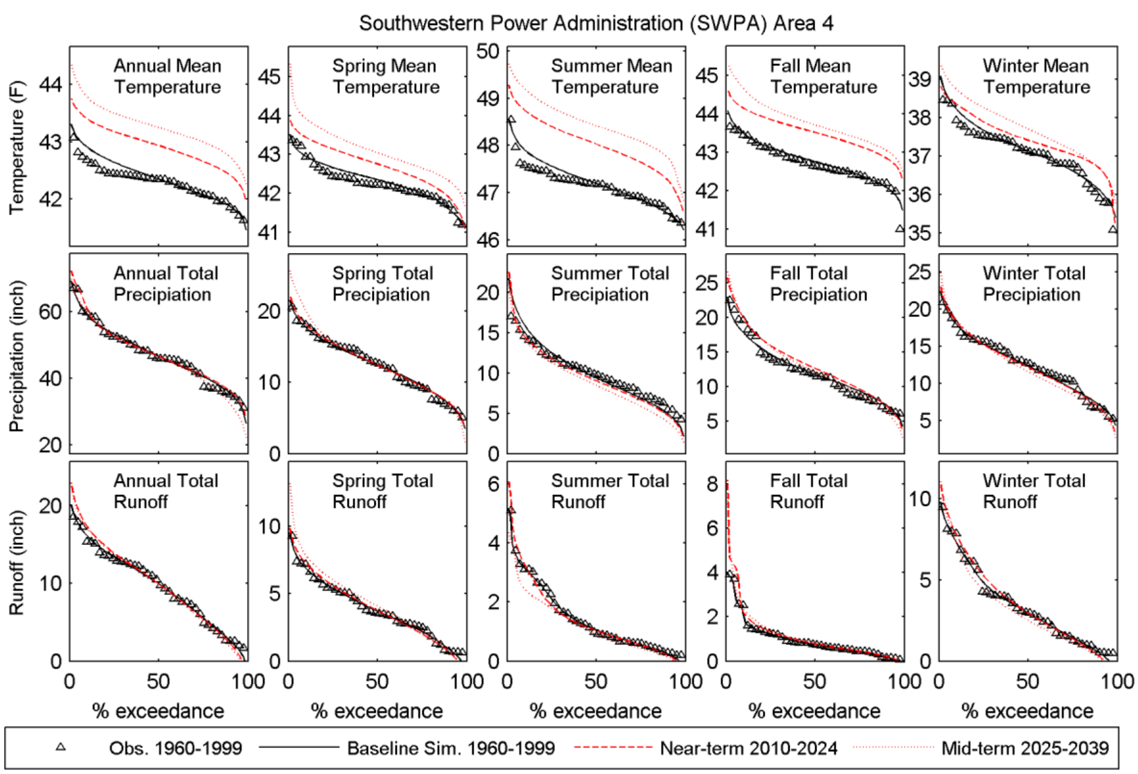

Western Area Power Administration (WAPA) Area 5
Annual Mean Temperature
Spring Mean Temperature
Summer Mean Temperature
Fall Mean Temperature
Winter Mean Temperature
Annual Total Precipitation
Spring Total Precipitation
Summer Total Precipitation
Fall Total Precipitation
Winter Total Precipitation
Annual Total Runoff
Spring Total Runoff
Summer Total Runoff
Fall Total Runoff
Winter Total Runoff
Temperature (F)
Precipitation (inch)
Runoff (inch)
% exceedance
Obs. 1960-1999
Baseline Sim. 1960-1999
Near-term 2010-2024
Mid-term 2025-2039

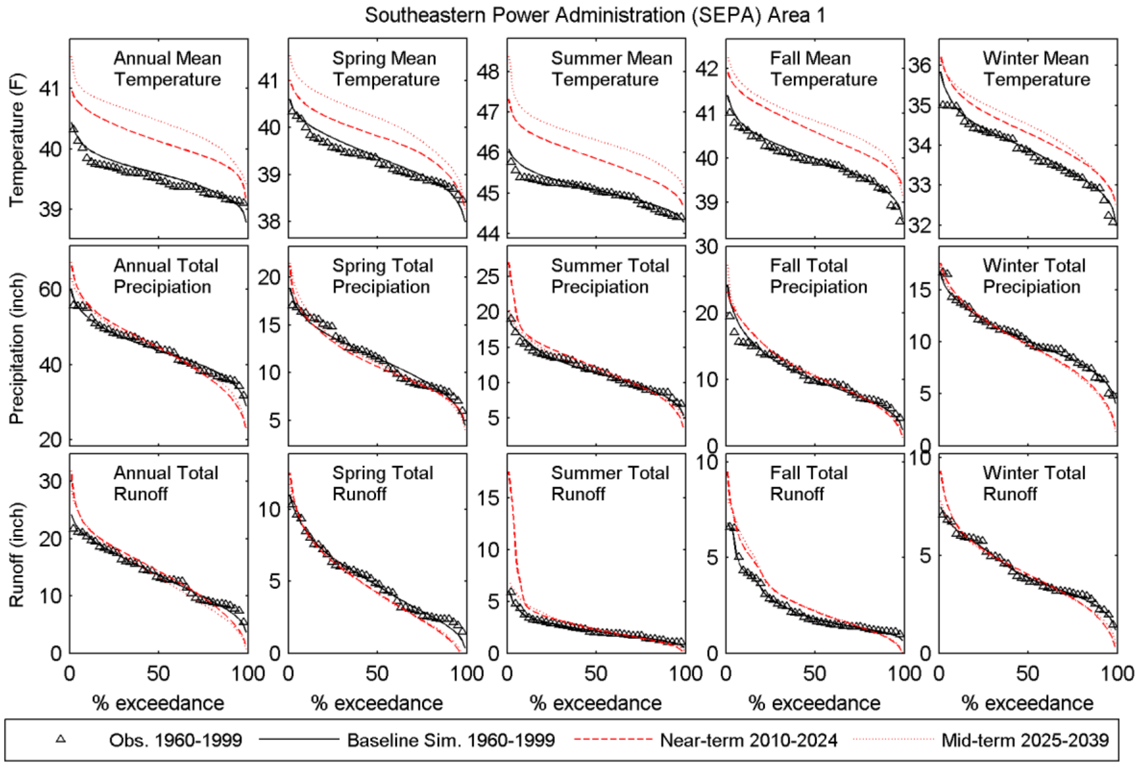

Western Area Power Administration (WAPA) Area 6
Annual Mean Temperature
Spring Mean Temperature
Summer Mean Temperature
Fall Mean Temperature
Winter Mean Temperature
Annual Total Precipitation
Spring Total Precipitation
Summer Total Precipitation
Fall Total Precipitation
Winter Total Precipitation
Annual Total Runoff
Spring Total Runoff
Summer Total Runoff
Fall Total Runoff
Winter Total Runoff
Temperature (F)
Precipitation (inch)
Runoff (inch)
% exceedance
Obs. 1960-1999
Baseline Sim. 1960-1999
Near-term 2010-2024
Mid-term 2025-2039

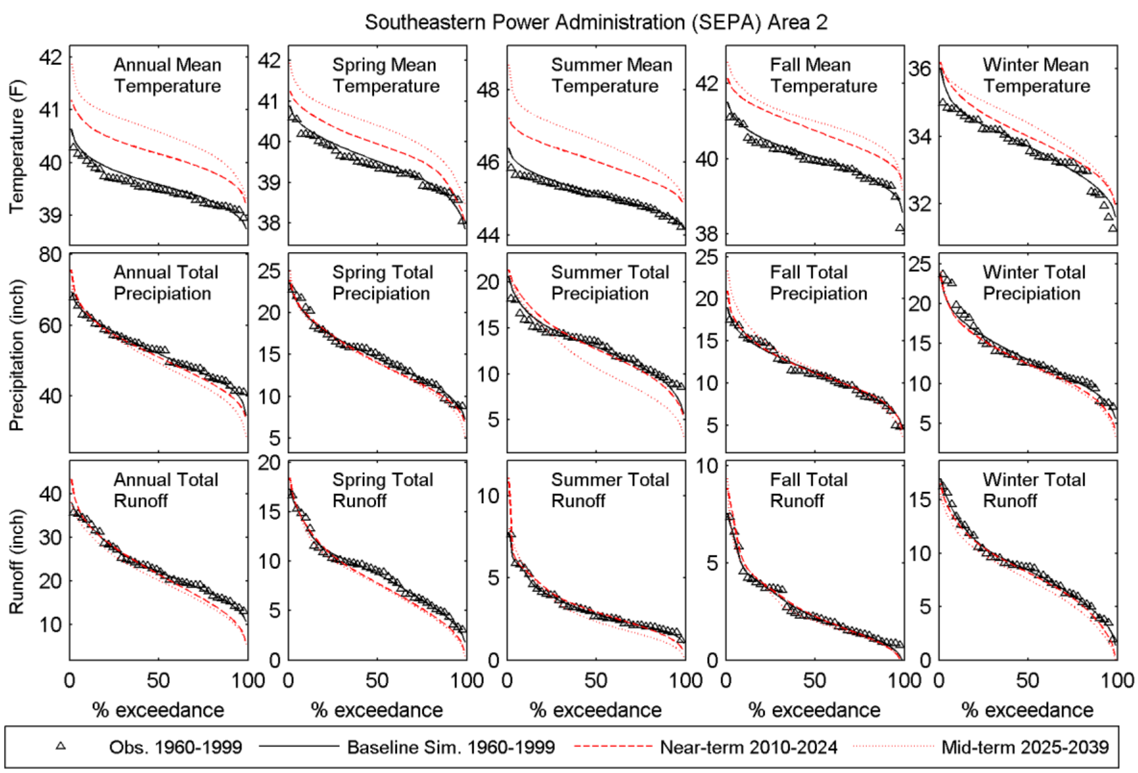

Southwestern Power Administration (SWPA) Area 1
Annual Mean Temperature
Spring Mean Temperature
Summer Mean Temperature
Fall Mean Temperature
Winter Mean Temperature
Annual Total Precipiation
Spring Total Precipiation
Summer Total Precipiation
Fall Total Precipiation
Winter Total Precipiation
Annual Total Runoff
Spring Total Runoff
Summer Total Runoff
Fall Total Runoff
Winter Total Runoff
Temperature (F)
Precipitation (inch)
Runoff (inch)
% exceedance
Obs. 1960-1999
Baseline Sim. 1960-1999
Near-term 2010-2024
Mid-term 2025-2039

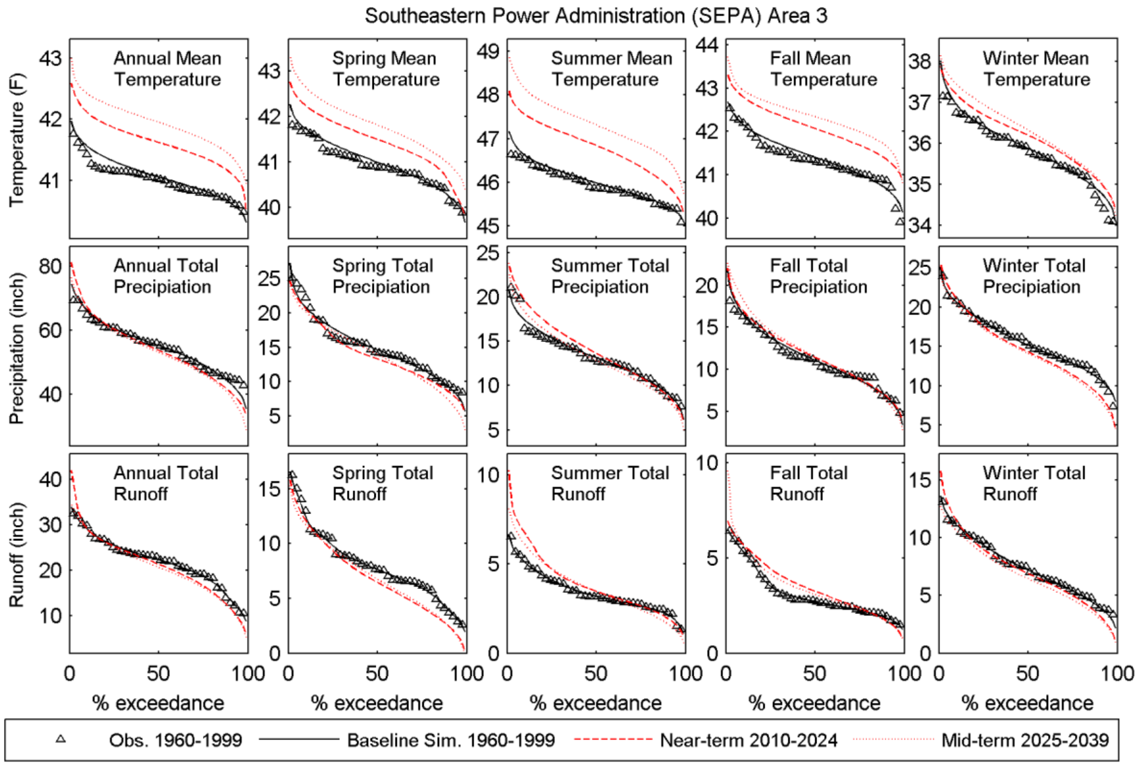

Southwestern Power Administration (SWPA) Area 2
Annual Mean Temperature
Spring Mean Temperature
Summer Mean Temperature
Fall Mean Temperature
Winter Mean Temperature
Annual Total Precipiation
Spring Total Precipiation
Summer Total Precipiation
Fall Total Precipiation
Winter Total Precipiation
Annual Total Runoff
Spring Total Runoff
Summer Total Runoff
Fall Total Runoff
Winter Total Runoff
Temperature (F)
Precipitation (inch)
Runoff (inch)
% exceedance
Obs. 1960-1999
Baseline Sim. 1960-1999
Near-term 2010-2024
Mid-term 2025-2039


Southwestern Power Administration (SWPA) Area 3
Annual Mean Temperature
Spring Mean Temperature
Summer Mean Temperature
Fall Mean Temperature
Winter Mean Temperature
Annual Total Precipiation
Spring Total Precipiation
Summer Total Precipiation
Fall Total Precipiation
Winter Total Precipiation
Annual Total Runoff
Spring Total Runoff
Summer Total Runoff
Fall Total Runoff
Winter Total Runoff
Temperature (F)
Precipitation (inch)
Runoff (inch)
% exceedance
Obs. 1960-1999
Baseline Sim. 1960-1999
Near-term 2010-2024
Mid-term 2025-2039

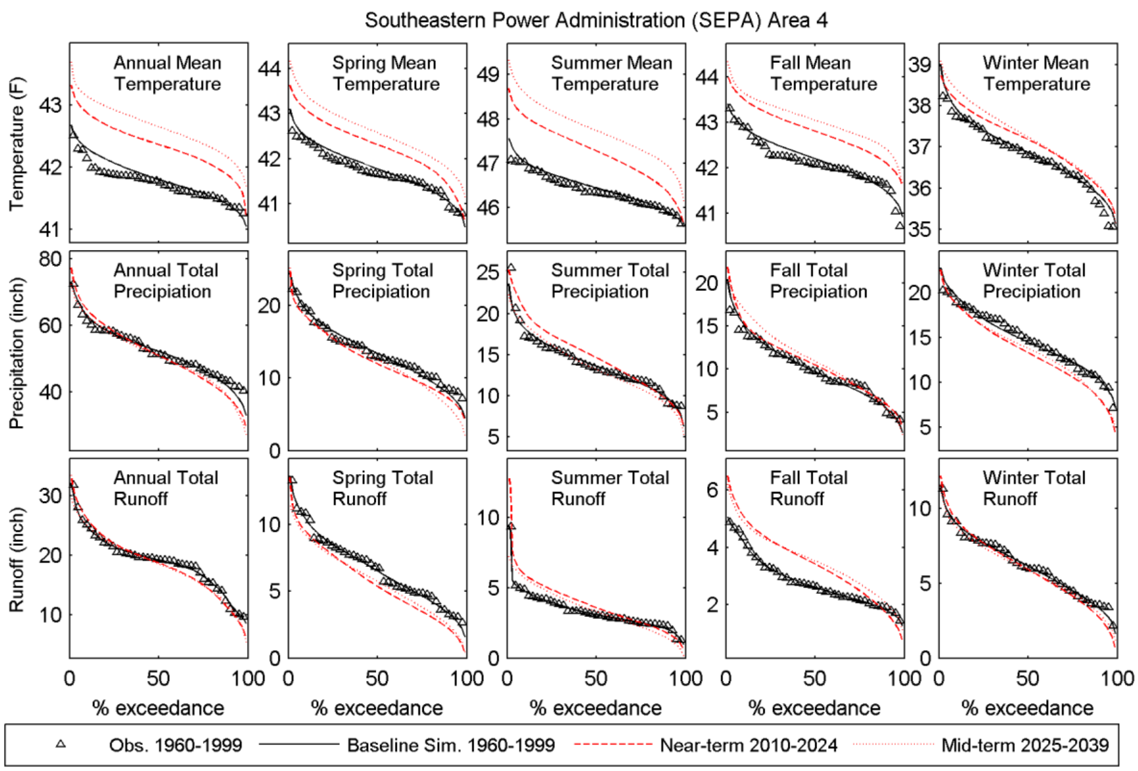

Southwestern Power Administration (SWPA) Area 4
Annual Mean Temperature
Spring Mean Temperature
Summer Mean Temperature
Fall Mean Temperature
Winter Mean Temperature
Annual Total Precipiation
Spring Total Precipiation
Summer Total Precipiation
Fall Total Precipiation
Winter Total Precipiation
Annual Total Runoff
Spring Total Runoff
Summer Total Runoff
Fall Total Runoff
Winter Total Runoff
Temperature (F)
Precipitation (inch)
Runoff (inch)
% exceedance
Obs. 1960-1999
Baseline Sim. 1960-1999
Near-term 2010-2024
Mid-term 2025-2039


Southeastern Power Administration (SEPA) Area 1
Annual Mean Temperature
Spring Mean Temperature
Summer Mean Temperature
Fall Mean Temperature
Winter Mean Temperature
Annual Total Precipitation
Spring Total Precipitation
Summer Total Precipitation
Fall Total Precipitation
Winter Total Precipitation
Annual Total Runoff
Spring Total Runoff
Summer Total Runoff
Fall Total Runoff
Winter Total Runoff
Temperature (F)
Precipitation (inch)
Runoff (inch)
% exceedance
Obs. 1960-1999
Baseline Sim. 1960-1999
Near-term 2010-2024
Mid-term 2025-2039


Southeastern Power Administration (SEPA) Area 2
Annual Mean Temperature
Spring Mean Temperature
Summer Mean Temperature
Fall Mean Temperature
Winter Mean Temperature
Annual Total Precipitation
Spring Total Precipitation
Summer Total Precipitation
Fall Total Precipitation
Winter Total Precipitation
Annual Total Runoff
Spring Total Runoff
Summer Total Runoff
Fall Total Runoff
Winter Total Runoff
Temperature (F)
Precipitation (inch)
Runoff (inch)
% exceedance
Obs. 1960-1999
Baseline Sim. 1960-1999
Near-term 2010-2024
Mid-term 2025-2039



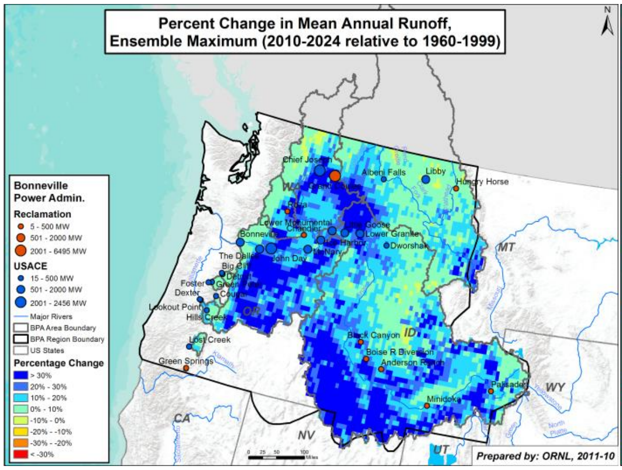
Southeastern Power Administration (SEPA) Area 3
Temperature (F)
Precipitation (inch)
Runoff (inch)
Annual Mean Temperature
Spring Mean Temperature
Summer Mean Temperature
Fall Mean Temperature
Winter Mean Temperature
Annual Total Precipitation
Spring Total Precipitation
Summer Total Precipitation
Fall Total Precipitation
Winter Total Precipitation
Annual Total Runoff
Spring Total Runoff
Summer Total Runoff
Fall Total Runoff
Winter Total Runoff
% exceedance
Obs. 1960-1999
Baseline Sim. 1960-1999
Near-term 2010-2024
Mid-term 2025-2039

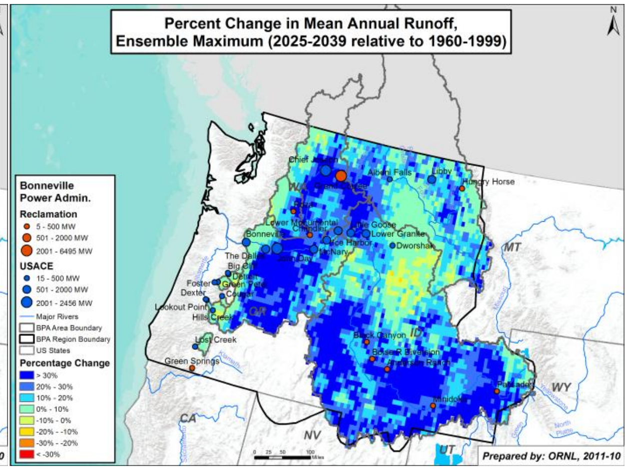


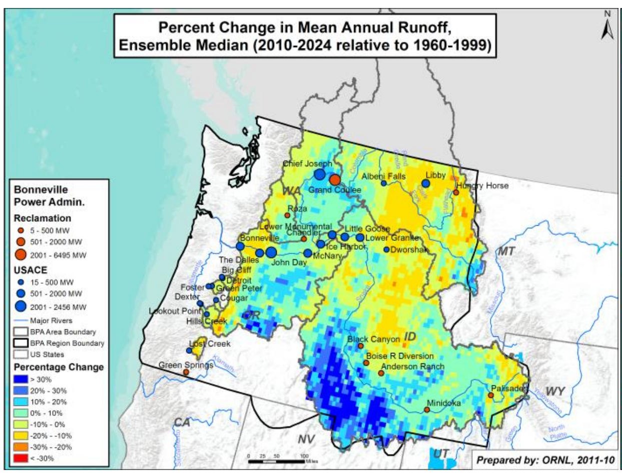
Southeastern Power Administration (SEPA) Area 4
Temperature (F)
Precipitation (inch)
Runoff (inch)
Annual Mean Temperature
Spring Mean Temperature
Summer Mean Temperature
Fall Mean Temperature
Winter Mean Temperature
Annual Total Precipitation
Spring Total Precipitation
Summer Total Precipitation
Fall Total Precipitation
Winter Total Precipitation
Annual Total Runoff
Spring Total Runoff
Summer Total Runoff
Fall Total Runoff
Winter Total Runoff
% exceedance
Obs. 1960-1999
Baseline Sim. 1960-1999
Near-term 2010-2024
Mid-term 2025-2039

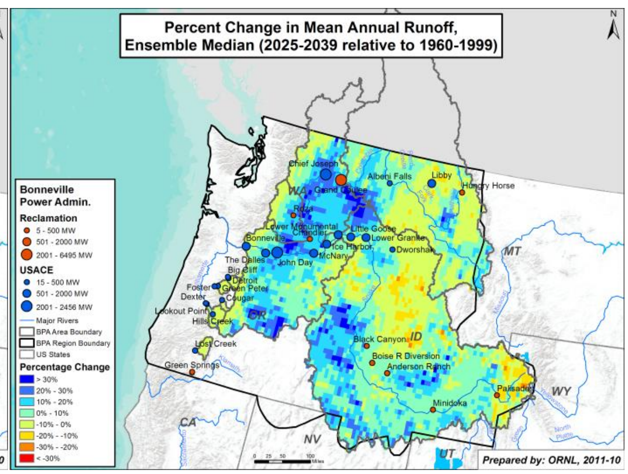
APPENDIX F. PERCENTAGE CHANGE IN MEAN ANNUAL RUNOFF

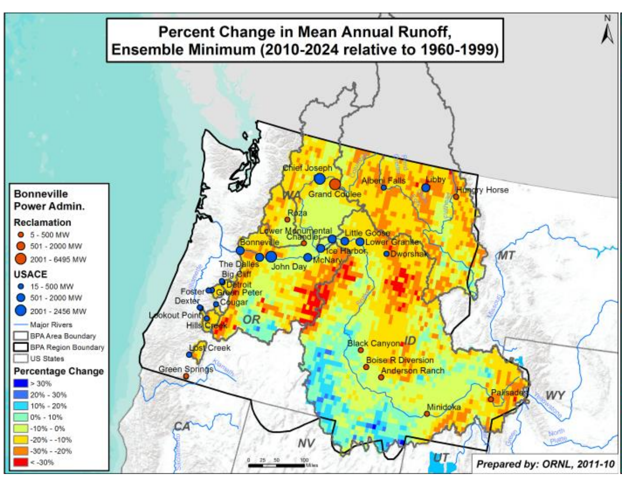
Bonneville Power Administration

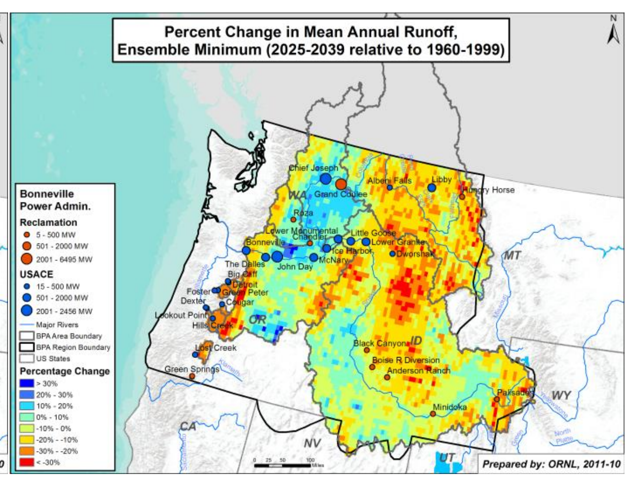




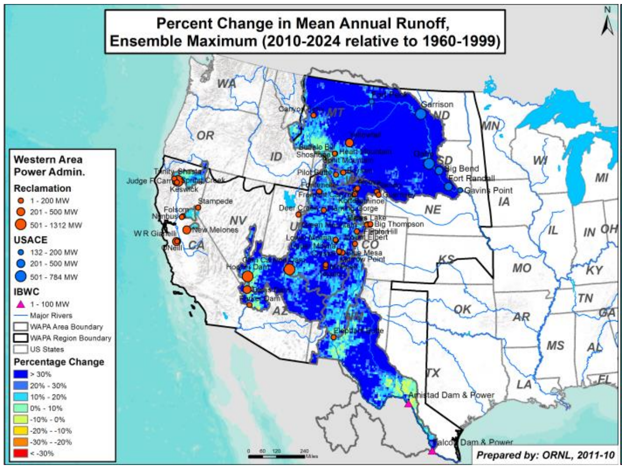


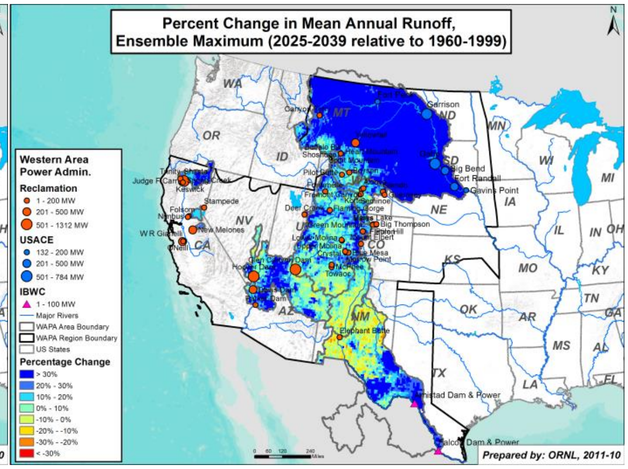


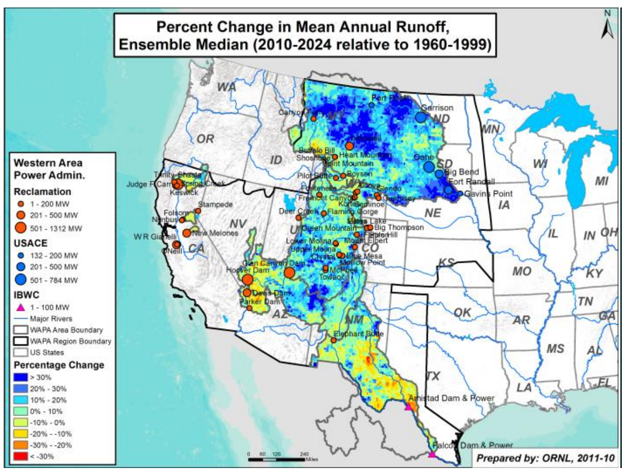


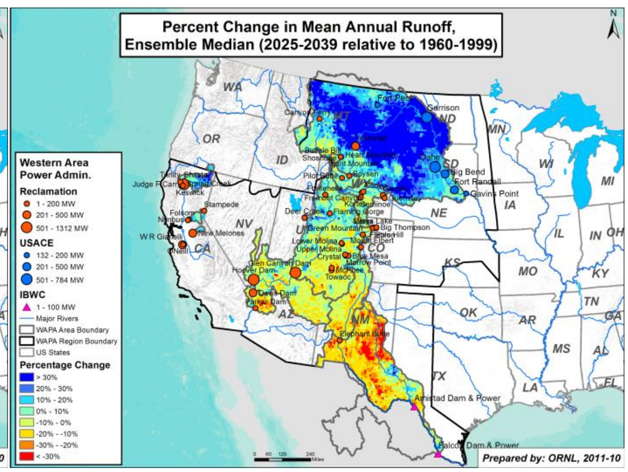


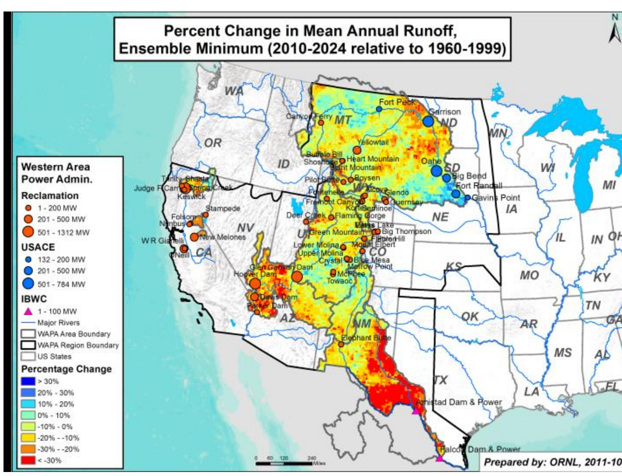
Western Power Administration

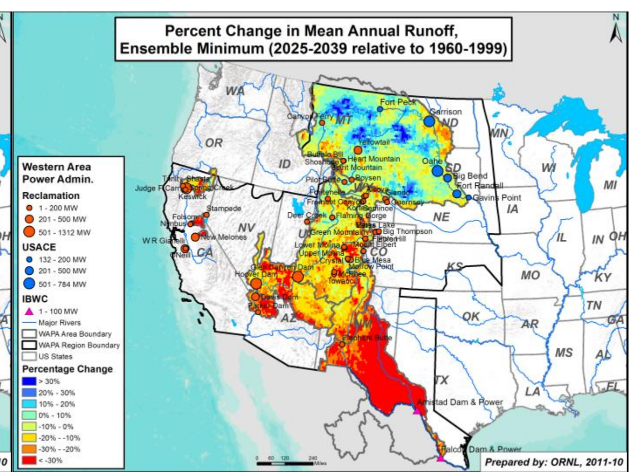




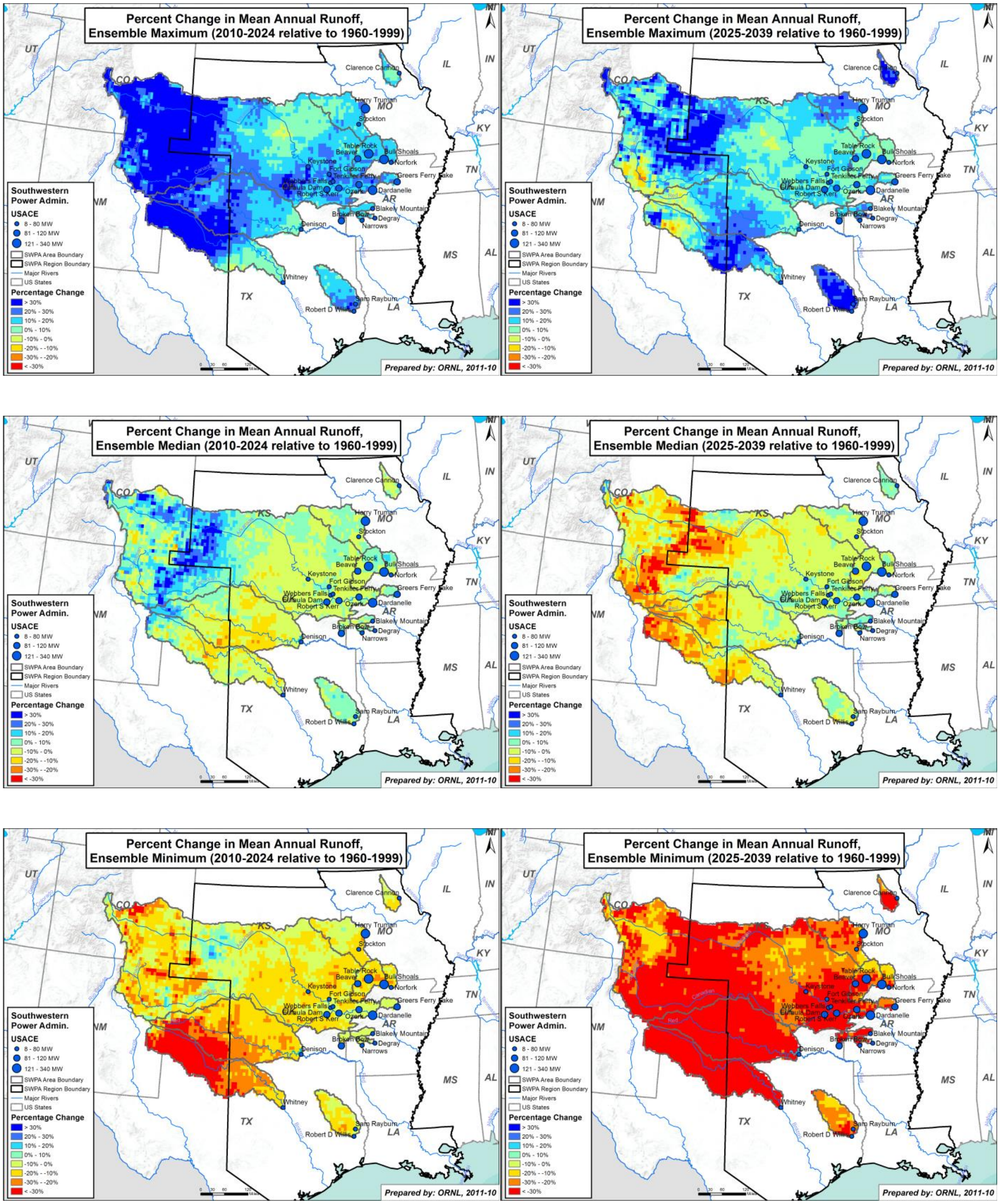


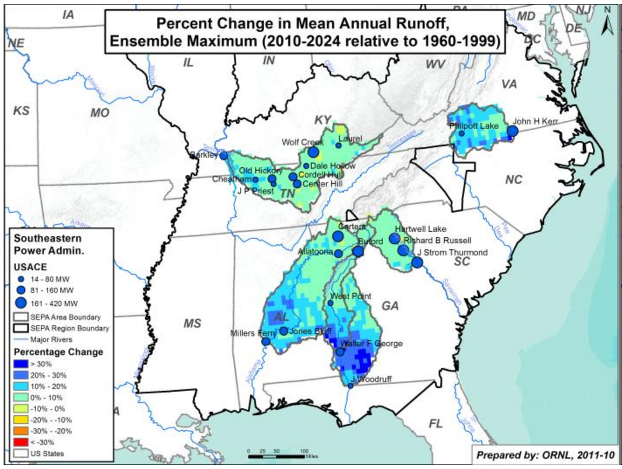


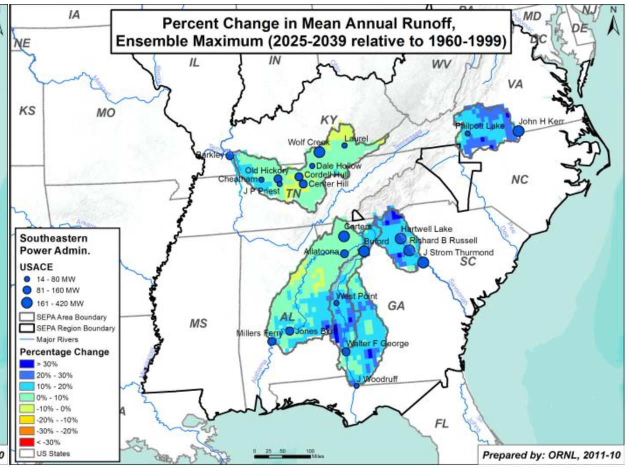


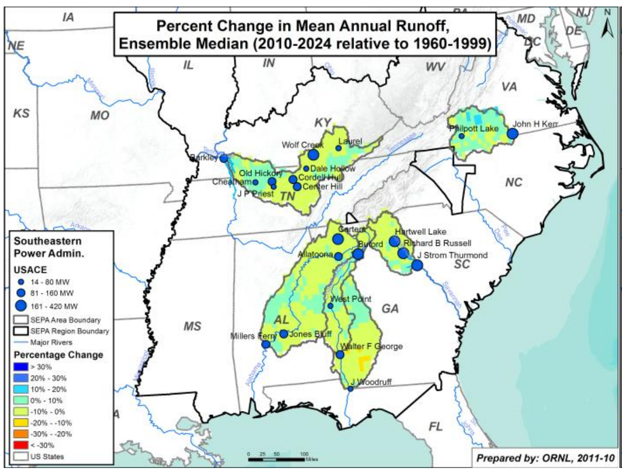


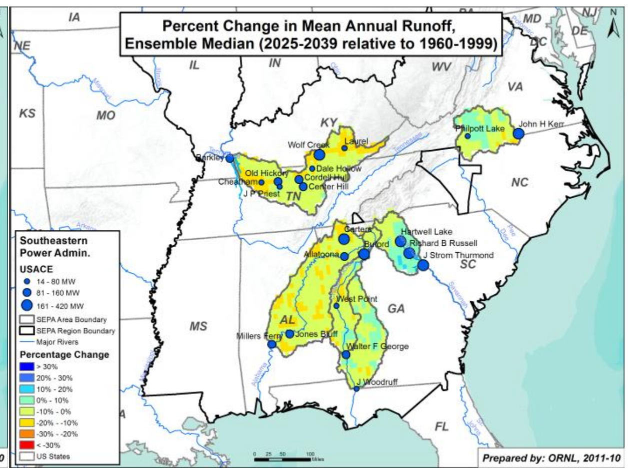
Southwestern Power Administration

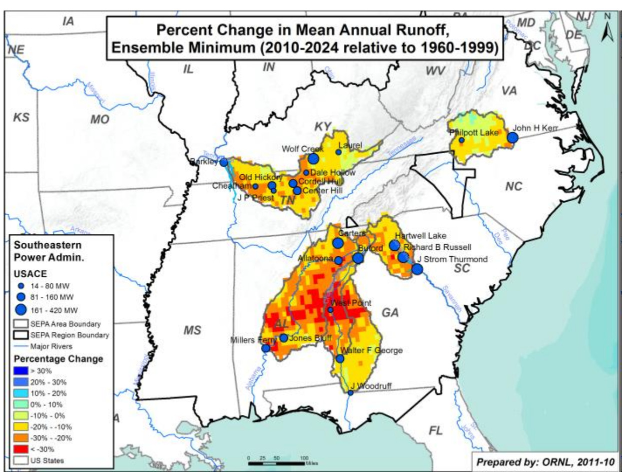


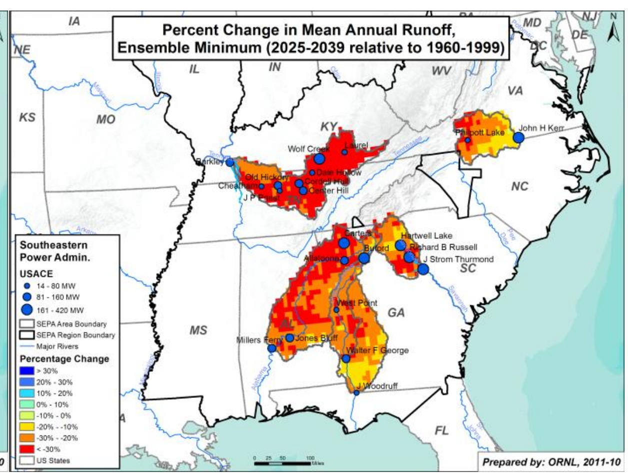

Percent Change in Mean Annual Runoff,
Ensemble Maximum (2010-2024 relative to 1960-1999)
Southeastern Power Admin.
USACE
14 - 80 MW
81 - 160 MW
161 - 420 MW
SEPA Area Boundary
SEPA Region Boundary
Major Rivers
Percentage Change
> 30%
20% - 30%
10% - 20%
0% - 10%
-10% - 0%
-20% - -10%
-30% - -20%
< -30%
US States
Prepared by: ORNL, 2011-10


Percent Change in Mean Annual Runoff,
Ensemble Maximum (2025-2039 relative to 1960-1999)
Southeastern Power Admin.
USACE
14 - 80 MW
81 - 160 MW
161 - 420 MW
SEPA Area Boundary
SEPA Region Boundary
Major Rivers
Percentage Change
> 30%
20% - 30%
10% - 20%
0% - 10%
-10% - 0%
-20% - -10%
-30% - -20%
< -30%
US States
Prepared by: ORNL, 2011-10


Percent Change in Mean Annual Runoff,
Ensemble Median (2010-2024 relative to 1960-1999)
Southeastern Power Admin.
USACE
14 - 80 MW
81 - 160 MW
161 - 420 MW
SEPA Area Boundary
SEPA Region Boundary
Major Rivers
Percentage Change
> 30%
20% - 30%
10% - 20%
0% - 10%
-10% - 0%
-20% - -10%
-30% - -20%
< -30%
US States
Prepared by: ORNL, 2011-10


Percent Change in Mean Annual Runoff,
Ensemble Median (2025-2039 relative to 1960-1999)
Southeastern Power Admin.
USACE
14 - 80 MW
81 - 160 MW
161 - 420 MW
SEPA Area Boundary
SEPA Region Boundary
Major Rivers
Percentage Change
> 30%
20% - 30%
10% - 20%
0% - 10%
-10% - 0%
-20% - -10%
-30% - -20%
< -30%
US States
Prepared by: ORNL, 2011-10


Percent Change in Mean Annual Runoff,
Ensemble Minimum (2010-2024 relative to 1960-1999)
Southeastern Power Admin.
USACE
14 - 80 MW
81 - 160 MW
161 - 420 MW
SEPA Area Boundary
SEPA Region Boundary
Major Rivers
Percentage Change
> 30%
20% - 30%
10% - 20%
0% - 10%
-10% - 0%
-20% - -10%
-30% - -20%
< -30%
US States
Prepared by: ORNL, 2011-10


Percent Change in Mean Annual Runoff,
Ensemble Minimum (2025-2039 relative to 1960-1999)
Southeastern Power Admin.
USACE
14 - 80 MW
81 - 160 MW
161 - 420 MW
SEPA Area Boundary
SEPA Region Boundary
Major Rivers
Percentage Change
> 30%
20% - 30%
10% - 20%
0% - 10%
-10% - 0%
-20% - -10%
-30% - -20%
< -30%
US States
Prepared by: ORNL, 2011-10

APPENDIX G. PROJECTED CHANGE OF WATER YEAR TYPE, BASED ON RUNOFF

PMA assessment area	Frequency of simulated water year type								
	Dry year			Normal year			Wet year		
	1960–1999 Baseline	2010–2024 Project.	2025–2039 Project.	1960–1999 Baseline	2010–2024 Project.	2025–2039 Project.	1960–1999 Baseline	2010–2024 Project.	2025–2039 Project.
BPA-1	20%	33%	23%	60%	52%	60%	20%	15%	17%
BPA-2	20%	33%	27%	60%	45%	53%	20%	21%	20%
BPA-3	20%	32%	21%	60%	51%	57%	20%	17%	21%
BPA-4	20%	31%	35%	60%	59%	51%	20%	11%	15%
WAPA-1	20%	16%	9%	60%	48%	45%	20%	36%	45%
WAPA-2	20%	11%	20%	60%	61%	61%	20%	28%	19%
WAPA-3	20%	13%	28%	60%	49%	52%	20%	37%	20%
WAPA-4	20%	13%	27%	60%	53%	55%	20%	33%	19%
WAPA-5	20%	23%	33%	60%	52%	57%	20%	25%	9%
WAPA-6	20%	21%	17%	60%	65%	63%	20%	13%	20%
SWPA-1	20%	16%	27%	60%	63%	57%	20%	21%	16%
SWPA-2	20%	21%	37%	60%	57%	52%	20%	21%	11%
SWPA-3	20%	20%	35%	60%	64%	59%	20%	16%	7%
SWPA-4	20%	19%	25%	60%	60%	52%	20%	21%	23%
SEPA-1	20%	24%	29%	60%	45%	45%	20%	31%	25%
SEPA-2	20%	35%	35%	60%	44%	49%	20%	21%	16%
SEPA-3	20%	31%	33%	60%	51%	45%	20%	19%	21%
SEPA-4	20%	28%	29%	60%	49%	53%	20%	23%	17%

Note: Wet/dry years are defined by the 20% and 80% quantiles of annual runoff in the baseline (1960–1999) simulation period.

APPENDIX H. PROJECTION OF HYDROPOWER GENERATION

Part A. Projected change of mean 15 year hydropower generation compared with the mean of simulated 1960–1999 annual hydropower generation across five ensemble members

PMA assessment area	Baseline 1960–1999 simulated generation (TWh/year)	Projected 2010–2024 change of generation (billion kWh/year)			Projected 2025–2039 change of generation (billion kWh/year)		
		Min. scenario	Med. scenario	Max. scenario	Min. scenario	Med. scenario	Max. scenario
PMA total	124.407	−4.656	−2.022	9.494	−9.614	−1.394	9.402
BPA total	80.631	−5.118	−3.869	4.144	−6.465	−0.044	2.233
BPA-1	25.177	−2.499	−1.779	1.695	−2.487	−0.105	0.595
BPA-2	12.901	−0.736	−0.633	0.744	−0.987	−0.293	1.177
BPA-3	40.747	−1.903	−1.401	1.666	−2.769	−0.092	1.187
BPA-4	1.806	−0.135	−0.083	0.038	−0.222	−0.026	0.026
WAPA total	29.874	0.548	3.482	5.022	−1.162	1.141	7.276
WAPA-1	10.614	−0.302	1.715	3.590	0.772	2.542	5.745
WAPA-2	1.478	−0.087	0.041	0.259	−0.101	0.011	0.111
WAPA-3	6.283	−0.323	0.750	1.028	−1.031	−0.374	0.587
WAPA-4	6.499	−0.452	0.555	0.848	−0.843	−0.190	0.505
WAPA-5	0.185	−0.028	0.012	0.026	−0.053	−0.011	0.013
WAPA-6	4.752	−0.429	0.088	0.285	−0.485	0.345	0.380
SWPA total	5.662	−0.180	−0.103	0.590	−1.287	0.037	0.171
SWPA-1	2.191	−0.080	−0.050	0.272	−0.564	−0.019	0.253
SWPA-2	2.640	−0.038	−0.001	0.200	−0.479	−0.069	0.092
SWPA-3	0.681	−0.092	−0.050	0.106	−0.223	−0.019	0.053
SWPA-4	0.149	−0.010	0.001	0.012	−0.020	−0.001	0.038
SEPA total	7.920	−0.824	0.044	0.336	−1.734	−0.045	0.175
SEPA-1	0.478	−0.032	0.022	0.066	−0.114	−0.008	0.099
SEPA-2	3.278	−0.392	0.049	0.159	−0.898	−0.209	0.048
SEPA-3	3.956	−0.504	−0.048	0.159	−0.708	−0.093	0.165
SEPA-4	0.208	−0.011	−0.004	0.010	−0.014	−0.003	0.008

Note: Min., med., and max. refer to the minimum, median, and maximum values from all members of the 9505 ensemble.

Part B. Projected change of mean 15 year hydropower generation compared with the observed 1989–2008 annual hydropower generation

PMA assessment area	Observed 1989–2008 annual generation (TWh/year)	Projected 2010–2024 change of generation (billion kWh/year)			Projected 2025–2039 change of generation (billion kWh/year)		
		Min. scenario	Med. scenario	Max. scenario	Min. scenario	Med. scenario	Max. scenario
PMA total	117.250	2.502	5.135	16.652	−2.457	5.764	16.560
BPA total	77.104	−1.591	−0.342	7.671	−2.938	3.483	5.760
BPA-1	24.373	−1.695	−0.975	2.499	−1.683	0.699	1.399
BPA-2	11.735	0.430	0.533	1.909	0.179	0.873	2.343
BPA-3	39.235	−0.391	0.111	3.178	−1.257	1.420	2.700
BPA-4	1.761	−0.090	−0.038	0.083	−0.177	0.019	0.071
WAPA total	26.795	3.628	6.562	8.102	1.917	4.221	10.356
WAPA-1	9.108	1.204	3.220	5.096	2.278	4.047	7.251
WAPA-2	1.380	0.010	0.139	0.357	−0.004	0.109	0.209
WAPA-3	5.558	0.402	1.475	1.753	−0.306	0.351	1.312
WAPA-4	5.972	0.075	1.083	1.376	−0.316	0.337	1.033
WAPA-5	0.179	−0.023	0.018	0.031	−0.048	−0.005	0.019
WAPA-6	4.598	−0.275	0.242	0.439	−0.331	0.500	0.534
SWPA total	5.862	−0.380	−0.303	0.390	−1.487	−0.163	−0.029
SWPA-1	2.191	−0.080	−0.050	0.272	−0.564	−0.019	0.253
SWPA-2	2.710	−0.107	−0.071	0.131	−0.549	−0.139	0.023
SWPA-3	0.794	−0.205	−0.164	−0.007	−0.336	−0.132	−0.060
SWPA-4	0.167	−0.028	−0.017	−0.005	−0.038	−0.019	0.021
SEPA total	7.489	−0.393	0.476	0.767	−1.303	0.386	0.607
SEPA-1	0.467	−0.021	0.033	0.077	−0.103	0.003	0.110
SEPA-2	3.189	−0.303	0.138	0.248	−0.809	−0.120	0.137
SEPA-3	3.634	−0.182	0.274	0.482	−0.386	0.229	0.487
SEPA-4	0.199	−0.002	0.005	0.019	−0.005	0.006	0.016

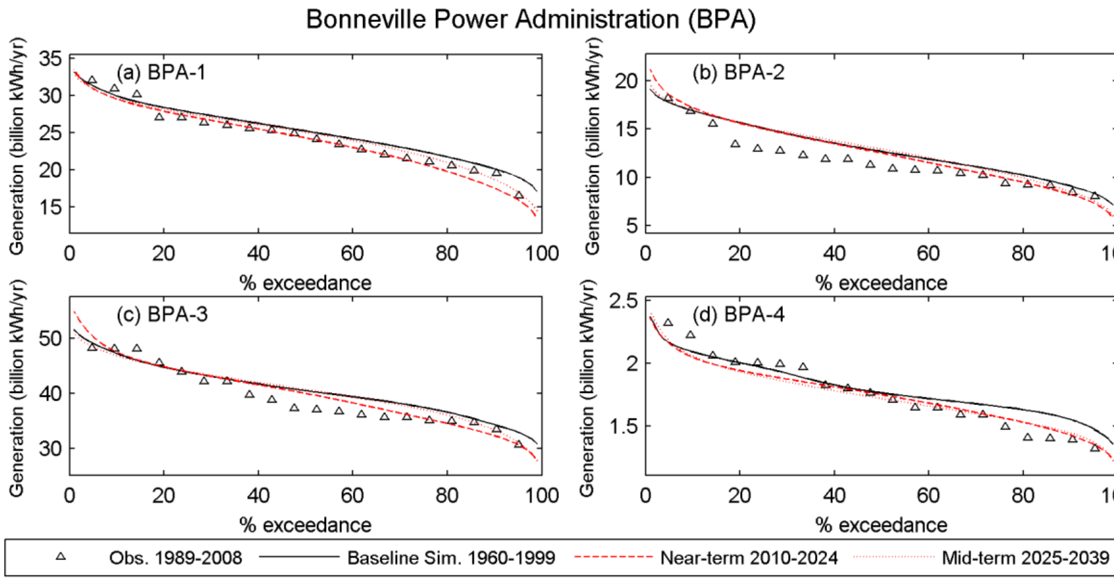
Note: Min., med., and max. refer to the minimum, median, and maximum values from all members of the 9505 ensemble.

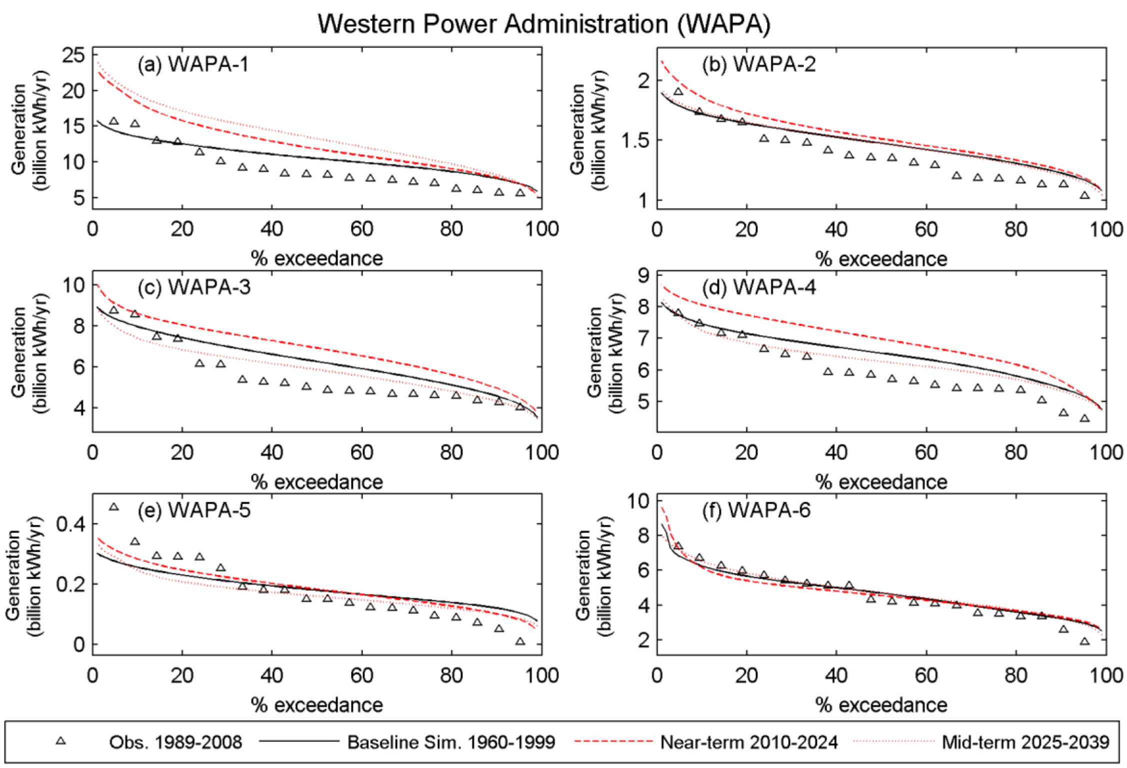
Part C. Projected change of 20 year minimum/maximum (or statistically equivalent 5% and 95% quantiles) annual hydropower generation

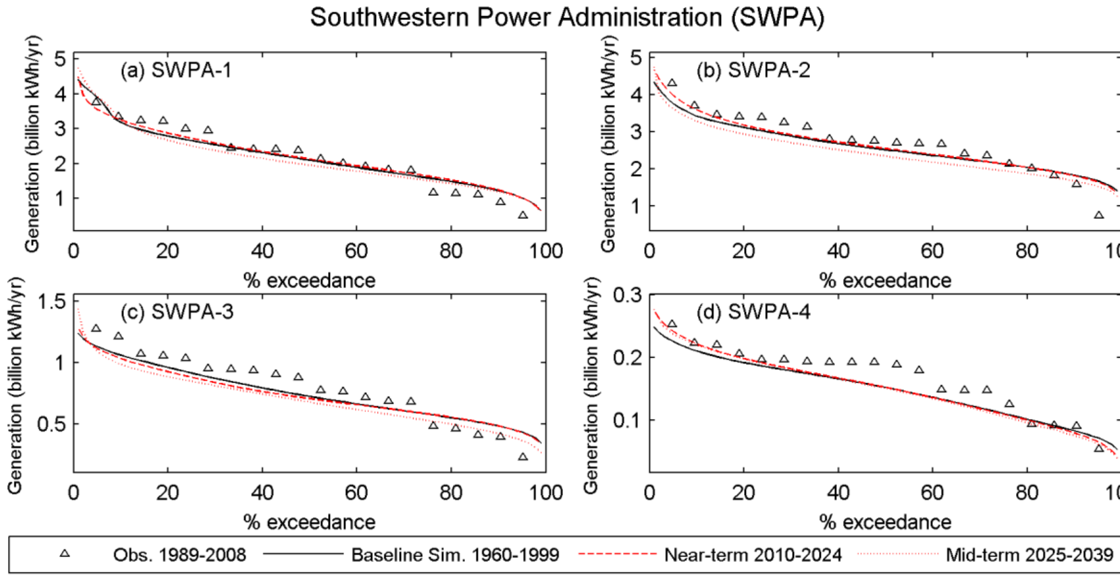
PMA assessment area	Annual hydropower generation (billion kWh/year)							
	Minimum or 5% quantile annual generation				Maximum or 95% quantile annual generation			
	1989–2008 Observation	1960–1999 Simulation	2010–2024 Projection	2025–2039 Projection	1989–2008 Observation	1960–1999 Simulation	2010–2024 Projection	2025–2039 Projection
BPA-1	16.59	19.66	16.86	17.08	32.04	31.37	29.82	30.65
BPA-2	8.03	8.69	8.08	7.96	18.20	17.10	17.94	17.42
BPA-3	30.65	33.55	31.76	31.40	48.23	48.99	49.74	48.08
BPA-4	1.32	1.48	1.38	1.43	2.32	2.15	2.15	2.15
WAPA-1	5.62	7.10	8.06	7.95	15.63	14.17	20.34	20.94
WAPA-2	1.04	1.19	1.24	1.19	1.90	1.75	1.97	1.79
WAPA-3	4.04	4.32	4.57	4.19	8.75	8.20	8.86	8.03
WAPA-4	4.45	5.31	5.20	5.15	7.80	7.67	8.06	7.63
WAPA-5	0.01	0.11	0.10	0.09	0.46	0.28	0.30	0.29
WAPA-6	1.90	3.21	3.27	3.11	7.37	6.75	7.15	7.19
SWPA-1	0.51	1.09	1.13	1.21	3.77	3.94	3.34	3.88
SWPA-2	0.74	1.79	1.84	1.74	4.30	3.81	4.05	3.61
SWPA-3	0.23	0.42	0.41	0.35	1.28	1.01	1.02	1.00
SWPA-4	0.05	0.08	0.08	0.07	0.25	0.22	0.23	0.23
SEPA-1	0.12	0.25	0.15	0.19	0.89	0.75	0.86	0.84
SEPA-2	1.66	2.32	2.10	1.93	4.24	4.56	4.46	4.33
SEPA-3	2.24	2.71	2.41	2.48	5.36	5.05	5.16	5.01
SEPA-4	0.07	0.17	0.17	0.17	0.24	0.24	0.24	0.24

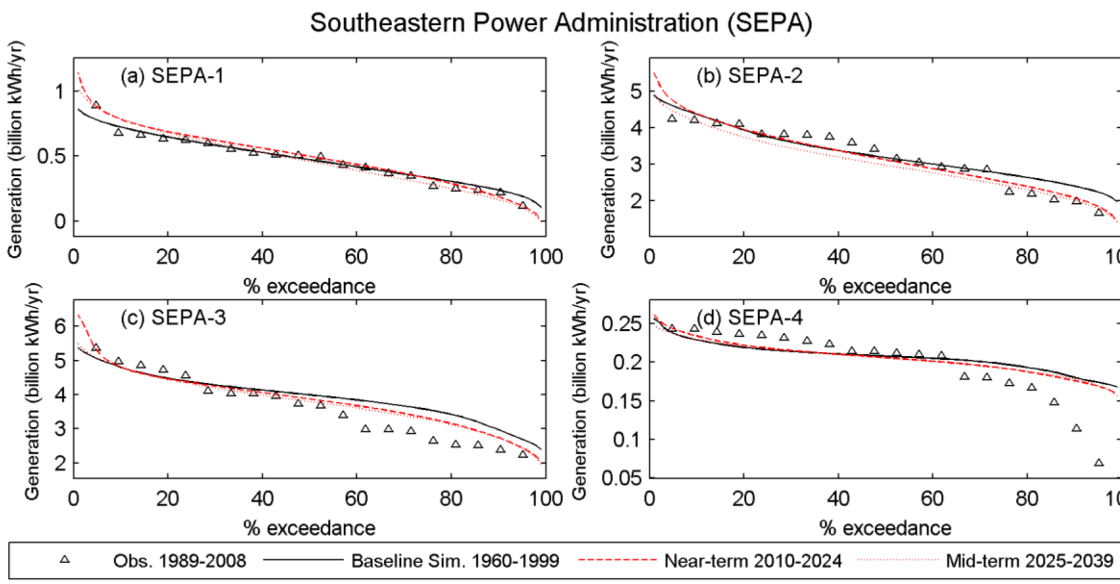
Note: Minimum/maximum are computed for the 20 year 1989–2008 observation; 5% and 95% quantiles are computed for 1960–1999, 2010–2024, and 2025–2039 simulations.

APPENDIX I. CUMULATIVE DISTRIBUTIONS OF OBSERVED AND SIMULATED ANNUAL HYDROPOWER GENERATION






Southwestern Power Administration (SWPA)
(a) SWPA-1
(b) SWPA-2
(c) SWPA-3
(d) SWPA-4
Generation (billion kWh/yr)
% exceedance
Obs. 1989-2008
Baseline Sim. 1960-1999
Near-term 2010-2024
Mid-term 2025-2039


Southeastern Power Administration (SEPA)
(a) SEPA-1
(b) SEPA-2
(c) SEPA-3
(d) SEPA-4
Generation (billion kWh/yr)
% exceedance
Obs. 1989-2008
Baseline Sim. 1960-1999
Near-term 2010-2024
Mid-term 2025-2039

APPENDIX J. SUMMARY OF RESPONSE TO KEY REVIEW COMMENTS

Technical reviewers of the draft 9505 Assessment were asked to provide general comments as well as detailed comments. The responses to the general comments are provided in the listing in this appendix, and responses to specific comments are on file at ORNL. In the listing below, the reviewers' areas of expertise or perspective are identified, but not the names or specific agencies. Statements in italics are the reviewer comments; they are followed by a description of revisions made to the final report, if any were required. Where there is no response listed, it was deemed that no change was required.

Reviewer A—federal water resources manager

A.1 Report represents an excellent first national level assessment of future hydropower in a changing climate. Lots of very good information. Suggest technical editor and focus on language to make it read clearer and more straight forward.

- Numerous changes have been made to clarify wording, and technical editor was used again for the final editing.

A.2 In general Chapter 2 could benefit from describing the approach in general before getting into the variables and methods. In general when reading that you are using PRISM for example, I am left wondering why do they need prism, the framework has not been developed that requires precipitation.

- Additional explanation has been added to Chapter 2.

Reviewer B—federal water resources manager and climate scientist

B.1 This initial, national-scale, comprehensive evaluation of the effects of climate change on federal hydropower is a needed and useful document, and I congratulate the authors on their study design and reporting, especially in light of the fact that there is no established procedure or method for doing so. My review comments relate to the study as conducted and with the assumptions described in Section 7.2.1.

B.2 Trends (third moment, if you will) vs. changes (second moment): Looking for trends in the data can obscure changes. It is the potential changes over time that will heavily impact hydrology and hence hydropower production. Moving the Figures in Appendix F and the table in Appendix G up to Chapter 2 to really highlight the potential changes up front. This is a recommended step before the report is finalized.

- Both the trend analysis method and presentation have been revised following reviewers' suggestions. In the final report, trend analysis is performed only on the entire 80-year (1960—2039) simulated data to help identify whether if a simulated trend if statistically significant, and the results are moved to the Conclusion section. The discussion of climate projection is now mainly based on changes (second moment) as suggested by the reviewer.

B.3 In this first application of these methods, and production of these relationships on national scale, the choice of GCMs, RCMs, and scenario is as good as most others. However, future editions of the 9505 report would be stronger with a sophisticated sampling strategy from the distribution of climate model results (at all scales).

- Additional reference to new climate modeling has been added to the final recommendations.

B.4 The report is in general heavy on the hydropower marketing and light on the hydrology. Since hydrology is the driving force, the next iteration ought to spend more time on projected hydrology and how it impacts hydropower production. It should also include changes in potential power usage due to socio-economic changes (e.g., conservation) and potential marked changes that might shift the pricing structure.

- More discussion has been added in the hydrology sections when appropriate. The power marketing sections have also been simplified to gain a better balance. A paragraph has been added in subsection 7.2.3 that mentions the value of conservation and demand response programs to manage climate change risk.

B.5 The finding that the multi-year runoff approach improves correlations in WAPA, particularly WAPA-4, is a significant finding and should be highlighted here and in the Executive summary, not simply within this regional discussion. This finding could be very useful to others examining climate impacts to hydropower at nonfederal locations, and represents an unanticipated benefit to the public and to the private sector from this study. Publishing this finding in a peer-reviewed journal is encouraged.

- The assessment reported has been revised accordingly.

B.6 Section 7.3, Preparing for future hydropower assessments, might include information on TVA power to provide a more complete assessment of Federal hydropower, along with some level of reporting about non-Federal hydropower installations at Federal facilities, as this category is growing and represents additional benefits at Federal projects.

- Section 7.3 has been revised accordingly.

Reviewer C—international climate change expert

C.1 *This is a very comprehensive analysis, very professionally done, by leading national experts. My only critical observation would be that its scope is rather narrow, and this weakens its bottom-line conclusions. For example, its treatment of climate change projections tends to miss such issues as variance and extremes, as contrasted with averages (e.g., prospects for seasonal droughts in the Southeast), and it tends to overlook issues related to climate change impacts on regional water demand over this period, which should be cross-matched against impacts on regional water supply in order to assess net water scarcity.*

- The scope of the 9505 report was defined by Congress as being narrowly focused on climate and hydropower. Consideration of non-hydropower issues is more in the scope of the 9503 report, so more cross-referencing was added to the final report. Recommendations were strengthened, calling for more board, integrated assessment in future efforts such as this.

Reviewer D—academic hydrologist and climate scientist

D.1 Despite the many limitations of the current report, the general study approach and the core of the analysis are defensible, and the results will be a valuable guide to some important elements of future impacts to annual hydropower production, and some of the future management challenges that are likely to be encountered.

D.2 Although the core of the annual hydropower analysis and the resulting report findings are basically sound, the current report is in great need of editorial attention, and the findings of the study need to be put in clearer context with the much more profound 21st century impacts to water management and hydropower resources that are projected in more detailed studies looking over longer time periods. In particular these relatively short-term impacts need to be placed in the context of a long-term trajectory that includes much larger impacts and the need for more profound changes in water management systems to cope with them. As it is now, the study paints a picture of climate change as a relatively minor source of impacts to hydropower systems. In the short-term this may be true, but the long-term impacts are very different. The concern is that policy makers will interpret this as a call to inaction, when in fact there is a pressing need to begin the arduous task of preparing for a world that is very different from the one we manage now.

- The longer-term effects of climate change to hydropower systems are certainly important, and there was no intention of saying otherwise. However, those longer term effects are much too difficult to predict at this time, when we do not know what types of hydropower systems we will have at that time. This first 9505 Assessment was scoped to concentrate on potential effects to the systems we have now. Additional explanation of this point has been added to the Conclusion section of the final report.

D.3 These systems are not entirely independent of each other, and the distribution of power is another important aspect of this problem. That this element is not evaluated should be discussed, and might also inform future study needs.

- Section 7.3 has been revised to address this comment.

D.4 Other elements of system response that are not included should be mentioned. In particular the role of potentially reduced head at storage projects due to drier (or hydrologic conditions displaying more persistence--Hurst phenomenon). Regression equations assume these factors do not change.

- It is true that head is not an independent variable in the R v G regressions, but we disagree that it is not accounted for in these empirical models. Variations in head are indirectly included in the observed generation data on which those regressions were develop. The effects of head are one of the sources of model error implicit in the regressions and associated statistics. We do agree that more detailed modeling could and should be done to more fully explain shorter-term and more project-specific variability in generation, but those types of analyses were outside the feasible scope of this first 9505 Assessment. Recommendations have been strengthened in final report to call for such expanded studies in the future, if resources allow.

D.5 Too much aggregation in the Western Region in the reporting of results?

- The decisions about areas of analysis were made jointly with the PMAs and not changed in the final report.

D.6 The frequent differences between the trends in observations and the baseline BCSD highlights the fact that decadal scale variability and/or limitations of the models will play a very important role in determining outcomes in any particular decade of the future.

- We agree with this comment. Given the current limitation of GCM and the way that a baseline GCM experiment is usually conducted (i.e., continuous simulation starting from the late 19^{th} century without interruption and without exhaustive regional calibration), the trend at a specific baseline decade will hardly be comparable to the observed ones. Therefore, as suggested by several reviewers, we now only focus on the relative change (future versus current) instead of trend. The results should be more defensible from methodological point of view.

D.7 Sections 2.2.1, 2.2.2, 2.2.3, 2.2.4 need to be rewritten with greater clarity and should be simplified to eliminate extraneous technical detail. I'm very familiar with all these methods, so I know what is being referred to, but those who are not already familiar with these details would be completely lost, I suspect. I've given specific editorial suggestions for several sections below, but have run out of time for editing at this level of detail. There are also frequent copy editing and ESL issues (such as missing articles) in these sections, which should be carefully reviewed and corrected. These sections seem to be particularly bad in this regard for some reason, but these errors are common throughout the report (see detailed comments below).

- We appreciate for the valuable suggestions. The report has been revised with the help from a technical editor.

D.8 The use of five scenarios from a single GCM greatly compresses the range of uncertainty examined. This is briefly mentioned in the discussion of the RMJOC analysis for the BPA regions, which used a bracketing approach, but needs to be mentioned earlier and brought into perspective for the entire study region. In general, ensembles from a single model tend to look more like each other than simulations from another model. I think this study limitation of the current study should inform the recommendations for future studies as well.

- We agree that five ensemble members from a single GCM may not seem sufficient to capture the multi-model uncertainty and it should be improved in the future studies. However, these five simulations are obtained from computationally-intensive dynamical downscaling and they can hopefully provide different insights than other studies such as Reclamation (2011c) and RMJOC (2010). As discussed in the revised Section 2.5, dynamical downscaling can naturally provide daily-scale meteorological outputs (required for VIC modeling) and hence the additional daily weather synthesizing will no longer be required. Sections 2 and 7 have been revised to address this issue.

D.9 SEPA Area 4 seems unnecessary and I think it should be combined with the other ACT ACF locations. I didn't find the explanation that the power was marketed differently to be that compelling.

- The decisions about areas of analysis were made jointly with the PMAs and not changed in the final report. Since that area is so small, it has little effect on any of the analyses or conclusions.

D.10 Slightly modified versions of the statement: "Although there could be more dry years as suggested by the simulations, the long-term change should be similar to what Southeastern encountered in the past twenty years." are used throughout the report. I think this reporting strategy is both vague and potentially misleading because it suggests that the next several decades will be a repeat of the last 20 years. This is not even a good assumption under conditions of observed natural variability. What is meant, I think, is that there is not a statistically meaningful difference in the ensemble means for the two time periods. Showing CDFs would help give a sense of the change in mean and variance of the ensemble that would quantify this better.

- Considered but not fully changed. In all cases, this type of statement is made in the hydropower subsections, not in talking about runoff. Annual generation integrates the full hydrograph for a year, including water storage, and will tend to be damped more than shorter-term changes in hydrology. Some clarification added to text, but general type of statement remains in the hydropower sections.

D.11 Figure 3-5 and its cousins throughout the paper would be greatly improved by showing inset CDFs based on the annual data (historical vs. future) similar to what is done in the appendices for the observed period.

- New plots of CDFs for all variables and seasons have been added to the final report. The reason they were not in the Review Draft was because that was originally thought to be a Report to Congress and therefore needed to be kept relatively simple.

D.12 An overarching conclusion from the study results is that the interannual variability (variance) of hydropower production is projected increase in the future. This suggests a possible decrease in the capacity to manage the resource, via increased forecast errors, limited storage, and competition (especially on the low flow side) with other management objectives. Such changes, although they have not been attributed directly to climate change have already been experienced in the late 20th century in the west, so there are historical analogues for these projections with which managers already have "on-the-ground" experience.

D.13 The response to climate change impacts to other system objectives (flood control and instream flow augmentation) will likely produce indirect impacts to hydropower systems that are not captured by this analysis. This is discussed briefly in the summary and conclusions (4296-4304), but should be brought into the discussion earlier.

- Additional references to these challenges have been added to the abstract and executive summary, and the discussion in the conclusions was expanded.

D.14 The role of decadal variability needs to be brought into the discussion of important impact pathways. Although future variability may express itself differently, 20th century patterns of relatively wet and dry periods have spanned several decades at a time (e.g. 1945-1975 vs. 1976-present. From the perspective of water resources management these impacts are essentially "permanent", in the sense that they span a water manager's career. At the same time, changes at longer time scales need to address the fact that the system will return to relatively wet or dry conditions, and the capacity to manage both situations needs to be considered. This aspect of system operation are frequently overlooked. In the early 1980s for example, the water resources management community in the Colorado Basin was focused entirely on short-term issues related to unusually high flows and managing full reservoirs. This short-sighted management focus ultimately led to a management system that was unprepared for the severe and extended drought that followed. The same issues are present in preparing for climate change.

D.15 An important shortcoming of this study as a supporting document for policy development is that it may have the unintended outcome of encouraging short-term thinking by limiting the scope of the analysis to a few decades into the future. Short term projections are needed, but need to be put into the context of a longer term trajectory that includes much larger changes. By focusing only on the short-term, the report may foster complacency and inaction in the management community which will increase vulnerability later. This problem is briefly alluded to in the summary and conclusions section, but should be brought forward into the introductory sections as a limitation of the current approach.

- Additional references to these challenges have been added to the abstract and executive summary, and the discussion in the conclusions was expanded.

D.16 A consistent level of technical detail and scientific background would greatly improve the introductory sections of the report. Later sections of the report are more homogeneous in this regard. The early sections of the report are very different, and are often clearly written by different authors with different backgrounds.

- We attempted to make Section 2 more clear in the final report with additional references and details on methods.

D.17 As noted above the report is, in general, in great need of editorial attention, and considerable work will need to be done to bring this material to an acceptable final product. I have identified some of the specific issues with the methods sections (which stand out in this regard), and I have also identified a number of details below, but I would suggest bringing a technical writer/editor on board to deal with the whole of the report.

- A technical editor has been consulted for the final editing.

Reviewer E—state agency hydrologist

E.1 Well organized document for high-level review of issue. More detailed studies would be needed at each facility to determine more specific impacts

- The need for more detailed, follow-up studies is highlighted in the conclusions.

E.2 While methods employed are standard of practice for climate change studies to date, water supply and water availability for hydropower uses is dependent to some extent on extreme events. I do not think these events are well represented in current methodologies and may need further study or acknowledgement of limitations

- We agree with this comment. Given the regional assessment approach, the short-duration extreme event (flood) and its impact on operation and water management cannot be characterized at each facility. Similar challenge exists for drought events where the non-hydropower water usage at each facility needs to be considered jointly. These will be listed as future challenges for the next 9505 Assessment report.

E.3 The document would benefit from someone editing the whole document for coherence in presentation. Right now it is very easy to tell it was written by multiple parties with different language capabilities and writing styles.

- A technical editor has been consulted for the final editing.

E.4 The conclusions and recommendations from the report are sensible relative to the level of study undertaken

Reviewer F—federal climate scientist

F1 I have a general concern with the approach and subsequent emphasis of the trend analysis as a primary data source for the assessment of risk. Mote et al August 2, 2011, EOS article on Climate Scenarios caution that one should "4) Obtain climate projections based on as many simulations, representing as many models and emissions scenarios, as possible". The approach in 9505 is monoculture using one emission scenario (A1B), one climate model (CCSM3), one regional model (RegCM3), and one hydrologic model (VIC). The trend analysis summary as described on page XIV in Note 3 of table ES-2 seems sophomoric. [Reference] P. Mote, L. Brekke, P. B. Duffy, and E. Maurer. Guidelines for Constructing Climate Scenarios, EOS, TRANSACTIONS AMERICAN GEOPHYSICAL UNION, VOL. 92, NO. 31, P. 257, 2011 doi:10.1029/2011EO310001

- The contents of trend analysis have been revised following reviewers' suggestions. We now only perform it on the entire 80-year (1960-2039) simulated data to help identify whether if a simulated trend if statistically significant. As stated in the revised report, our main purpose is to investigate on how to utilize the existing GCM climate projection to inform risk assessment of future water availability for hydropower generation instead of on the climate change itself. Therefore, we can only allocate the limited resources for the most reasonable usage. In addition, our 9505 simulation is based on dynamical downscaling instead of statistical ones adopted by several other recent climate assessment (e.g., Reclamation [2011c] and RMJOC [2010]), which may provide further insights for the uncertainty caused by different downscaling approaches.

F.2 Application of the methodology for the four PMA is propagates the overall concerns I raise for the 9505 Assessment approach when assessing the impact of changes in climate on hydropower production.

- DOE required that one consistent assessment approach be used across all the PMA to enable more consistent comparisons.

Reviewer G—federal hydrologist

G.1 We have reviewed the subject report, per your request. We focused primarily on Section 2, which describes the Assessment Approach as that provides the rationale for everything else that was done. Although we are not convinced that the use of downscaled GCM output provides the only meaningful basis for assessing hydropower requirements decades into the future, we do appreciate that DOE had to select this approach in responding to the requirements of the SECURE Water Act. Generally speaking, the material on global modeling in section 2.2.1 provides a reasonable insight into the limitations and uncertainty associated with such model projections of future climate. In that regard, the authors were honest in their characterization of the realism of such projections. USGS has other general suggestions to offer. Editorial and minor technical comments are enclosed in the attached .pdf file.

Reviewer H—water resource manager

H.1 I focused on the West in general and Texas in specific with an emphasis on water. I found the writing and graphics methodical, clear, and concise. The abstract doesn't state anything about the results of the study. I state this recognizing that this may be the required format for DOE; however, without a "real" abstract or an executive summary, readers, particularly policy-driven readers, will have to work to understand the overall conclusions of the study.

- The report style is to keep the abstract short and include results summaries in the Executive Summary.

H.2 The word "will" is used a lot in this report, especially in the Summary and Conclusions section. For example, "drier water years will be substantially more frequent". Given that these are modeled predictions with a fair amount of uncertainty to them, it would be far better to use the words "are projected" instead of "will". More awkward, but more accurate.

- The report has been modified based on this review comment.

H.3 The results on temperature, rainfall, and runoff projections are consistent with what I've seen elsewhere.

Reviewer I – federal power manager

I.1 Ensure consistent spacing after periods at the end of a sentence (sometimes none, sometimes one, sometimes two)

- It has been checked and changed in the revised report.

I.2 Several wording changes that were made in the body of the report, per comments/feedback, were not also made in the Executive Summary. It appears the Executive Summary was written prior to receiving the PMA feedback (as the Executive Summary was not provided for PMA review), or at least it was not resolved with changes made in the body. Suggest making the same changes provided by the PMAs in the Executive Summary as were made in the body of the report.

- The Executive Summary has been largely revised for clarity.

I.3 In reviewing the Executive Summary section on the Southwestern Region, it became apparent that the written discussion is not entirely supported by the table provided (Table ES-4). Neither is wrong, but presenting only Table ES-4 and not any of the other Figures/Tables that are provided in the body of the report, the written discussion is not fully supported. In particular, take the statement on page xvi, lines 573-574: "There was also an indication that this region may experience less precipitation in the summer with a possible increase in precipitation in the spring." While this statement is correct, it is not visible or supported by Table ES-4. Especially the part about possible increase in precipitation in the spring – in the body of the report, between the written discussion and Figure 5-4 this becomes apparent, but viewing only Table ES-4 (or Table 5-4 in the main body), it appears contradictory. I assume this is possibly the case for the other PMAs that may also have written discussion that appears contradictory to the respective Table provided in the Executive Summary. These Tables are quite large and detailed for an Executive Summary and do not support the entire analysis for each PMA region (by not including the other supporting Figures). As there is not one Table or Figure that tells the whole analysis story, suggest removing the Tables ES-2, ES-3, ES-4, and ES-5 in the Executive Summary and provide only the written discussion.

- The contents of trend analysis have been revised following reviewers' suggestions. We now only perform it on the entire 80-year (1960–2039) simulated data to help identify whether if a simulated trend if statistically significant. The Execute Summary is also large revised.

Reviewer J—federal water resources analyst

J.1 The Executive Summary is long - I know you are trying to get all the pertinent details in. While the Conclusions in the Executive Summary do discuss the need to integrate your climate change impact findings with the other impacts to federal hydropower generation, I suggest two things. 1) The Executive Summary needs to make it very clear that this report ONLY looks at the impacts of climate change and 2) That the executive summary list the other uses of the water to make sure Congress understands the issues - population growth, agriculture, conservation, recreation etc. - not just "water resource management decisions".

- The Executive Summary has been largely revised for clarity. Unfortunately, that just made it longer.

Reviewer K—Laboratory water resources modeler
K.1 Overall this is a good report. I know the availability of data is difficult but you have done well with what you have. This provides a nice first look at climate and hydropower production at a large scale

Reviewer L—academic hydrologist and climate scientist
L.1 Extremely well organized and written. Excellent graphs and figures that clearly convey results. This is very useful information for stakeholders.

Reviewer M—federal environmental analyst
M.1 We appreciate the balanced assessment of the complications due to competing pressures and demand for water use - including for ecosystems. Those parts of the report I reviewed are lucidly written and the tone is almost perfectly neutral which makes it accessible to a wide audience. There is a tendency in parts of the report to assume the reader knows what the author knows, or will otherwise be able to infer the correct meaning

- Additional references were added for background in the revised report.

M.2 Consider beginning each Region with a punch line e.g., … is projected to see no significant change albeit some projections lean toward minor temp increase

- Such summary statements will be in the Report to Congress.

M.3 Consider building a table showing key stats by project e.g., average age, runoff to precip %, tot megawatts, …

- Some key statistics are summarized in Appendix B and each PMA section.

M.4 Can we (and would it be useful to) show the projected change in runoff as a % of precip?

- We appreciate this suggestion but decided not to show the change of runoff in terms of percentage of precipitation. The change of runoff is determined both by precipitation and temperature (through evaporation), so it may be somewhat misleading to summarize runoff only in terms of precipitation.